Final Report

An Integrated Partnership to Create and Lead the Solar Codes and Standards Working Group

With Complete Summary of
STATEMENT OF PROJECT OBJECTIVES

Submitted By:
New Mexico State University

Report Submitted for Cooperative Agreement DE-FC36-07GO17034

Executive Summary

The DOE grant, "An Integrated Partnership to Create and Lead the Solar Codes and Standards Working Group," to New Mexico State University created the Solar America Board for Codes and Standards (Solar ABCs). From 2007 – 2013 with funding from this grant, Solar ABCs identified current issues, established a dialogue among key stakeholders, and catalyzed appropriate activities to support the development of codes and standards that facilitated the installation of high quality, safe photovoltaic systems. Solar ABCs brought the following resources to the PV stakeholder community:

1. Formal coordination in the planning or revision of interrelated codes and standards removing "stove pipes" that have only roofing experts working on roofing codes, PV experts on PV codes, fire enforcement experts working on fire codes, etc.
2. A conduit through which all interested stakeholders were able to see the steps being taken in the development or modification of codes and standards and participate directly in the processes.
3. A central clearing house for new documents, standards, proposed standards, analytical studies, and recommendations of best practices available to the PV community.
4. A forum of experts that invites and welcomes all interested parties into the process of performing studies, evaluating results, and building consensus on standards and code-related topics that affect all aspects of the market.
5. A biennial gap analysis to formally survey the PV community to identify needs that are unmet and inhibiting the market and necessary technical developments.

Solar ABCs Organization

Through 2013, Solar ABCs was a partnership of eleven organizations, who all received funding through this grant. In addition to New Mexico State University, the partners included Arizona State University, BEW Engineering (later DNV-GL), Brooks Engineering, Florida Solar Energy Center, Interstate Renewable Energy Council, North Carolina Solar Center, PowerMark, Sherwood Associates, Sunset Technologies, and Underwriter Laboratories.

At the beginning of the grant, the partners developed a Charter, which described how the different partners and constituencies would work together to accomplish program objectives and provided a common understanding of how the project would be managed. The credibility and authority of the Solar ABCs decisions and work products derived from cooperative efforts and consideration of a wide range of concerns and perspectives and the charter ensured a fair and open decision-making process.

The Charter created a Steering Committee, which was responsible for all decision-making including setting strategic priorities and approving policies and reports.

The Steering Committee also provided direction for the Project Administrator. The Steering Committee membership included the eleven partner organizations plus representatives from DOE, National Renewable Energy Laboratory, Sandia National Laboratories and the Advisory Committee. The Steering Committee met monthly for the duration of the grant.

The Charter also created an Advisory Committee, composed of a balance of stakeholders such as industry, utilities, trade organizations, advocacy groups, individuals and states. The Advisory Committee provided recommendations to the Steering Committee and provided support to Solar ABCs in the completion of deliverables. The Advisory Committee met quarterly.

Larry Sherwood of Sherwood Associates was the Project Administrator and was responsible for the operation of Solar ABCs.

Communications

The number of Solar ABCs Stakeholders grew consistently and steadily throughout the grant period showing strong interest in Solar ABCs events and products. The stakeholders numbered over 2,000 at the end of the grant. Solar ABCs distributed a quarterly newsletter to stakeholders to provide an update of recent Solar ABCs reports, activities, and discussion of other related PV codes and standards activities.

The Solar ABCs website was originally launched in 2007 and redesigned in 2011. The site is a centralized source of information regarding PV codes and standards and provides information on each Solar ABCs report, upcoming events, current codes and standards issues and information on important codes and standards development organizations.

The Solar ABCs held annual meetings to provide all interested PV stakeholders with an update and review of all major Solar ABCs projects and other activities undertaken in the preceding year. The Solar ABCs scheduled this meeting to coincide with the annual Solar Power International conference as the best way to attract and increase attendance. Between 100 and 200 people attended each year.

The Solar ABCs issued press releases and conducted other outreach announcing key study reports to a list of targeted media and stakeholders in order to increase visibility and ultimately increase access to Solar ABCs' work products by stakeholders.

Gap Analysis

Solar ABCs conducted three Gap Analyses, which determined the Solar ABCs priorities so it could respond to the needs of solar stakeholders in an effective and optimal way. Each gap analysis received input from solar stakeholders, the Advisory Committee and Steering Committee. The Gap Analyses allowed Solar ABCs

to be nimble and respond to important new issues and were not anticipated when the grant was awarded.

Code and Standards Development and Education

International Electrotechnical Commission (IEC)

Solar ABCs funded the IEC Technical Committee 82 Secretariat, the U.S. Technical Advisory Group (USTAG) and one of the working group chairs. Through the grant period the number of members of the USTAG increased to a record high and was the largest TAG in the U.S. The IEC Technical Committee and its Workings Groups met throughout the grant period and developed and published many standards.

With the adoption of IEC 61853, good module performance data is now being collected as manufacturers comply with this standard. However, the standard did not require manufacturers to make this data publicly available and therefore it is not available as inputs to performance models. Solar ABCs proposed an amendment to IEC 61853 addressing this issue.

Solar ABCs funded validation studies for module power ratings according to IEC 61853-1 and 61853-2.

National Electrical Code

Solar ABCs, in conjunction with the PV Industry Forum, facilitated a forum for proposals, discussion, and develop of recommendations for the revisions to the National Electrical Code for both the 2011 and 2014 revision cycles. For each cycle, Solar ABCs hosted several in-person stakeholder meetings that resulted in submission of dozens of proposals. Solar ABCS also funded Bill Brooks participation as a member of Code Making Panel 4 and several NFPA appointed Task Forces.

Solar ABCs funded or partially funded many trainings for code and fire officials around the U.S.

UL Standards

UL safety standards are critical to the deployment of PV and related technologies. Through Solar ABCs, UL and others worked to solve problems related to exiting standards, harmonize U.S. National Standards with international standards, and create new standards. Work included Arc Fault Circuit Interupters (UL 1699B), UL 1703, UL 1741, and other existing and new standards.

International Building Code

The adoption of the 2012 International Building Code and the International Residential Code provided challenges to the PV industry on fire classification rating based on Solar ABCs research described elsewhere in this report. Solar ABCs worked with diverse stakeholders to develop and publish a white paper on the

impacts of the 2012 code changes with a detailed emphasis on fire classification rating.

Fire Codes

Solar ABCs published a report providing the context and background information for the California Department of Forestry and Fire Protection's (CAL FIRE's) Solar Photovoltaic Installation Guideline (Guideline), which was released on April 22, 2008. In May 2010, the International Code Council (ICC) approved a revised version of the Guideline for inclusion in the 2012 version of the International Fire Code (IFC).

Standard Development

Solar ABCs developed a recommendation on PV module power rating tolerances. With input from stakeholders, Solar ABCs developed a draft standard for power rating tolerances and recommended that UL adopt this standard.

Solar ABCS developed standard language for supply chain prequalification specifications. SEMI used this proposal to write a standard for procurement of solar cells.

Code and Standard Issues

Fire Classification Rating

Solar ABCs and UL investigated with research experiments whether and how the presence of stand-off mounted PV arrays may affect the fire class rating of common roof covering materials. In particular, these tests were initiated in response to questions from stakeholders about the language in the UL Guide Card that stated that PV modules may or may not reduce the fire class rating of roof coverings when modules of a lower rating are installed above a roof covering with a higher rating. All tests were conducted by UL in Northbrook, IL, and the results published in eight UL Research Reports.

Early research results demonstrated that the fire class rating of the PV module alone (determined according to American National Standards Institute [ANSI]/UL 1703-2012) may not accurately predict the fire resistance properties of the system composed of PV array, mounting structure, and roof covering. Based on these results, stakeholders recognized the need to develop a new fire classification test for the PV module, mounting hardware, and roof assembly as one system. Over the next two years, the underlying principles of the new test were refined and a new PV system flammability test regime was developed. In July 2013, the UL 1703 Standards Technical Panel (STP) adopted the new fire classification test into the standard. Solar ABCs organized and facilitated over a dozen stakeholder meetings to provide stakeholder input into the development of this new controversial test.

Solar ABCs published two reports to explain the issues and describe the new test.

Ground-Fault Protection to Prevent Fires
Photovoltaic systems have caused fires on at least two large buildings. The fires have been traced to a detection blind spot that causes the ground fault system to be ineffective. To address this problem, Solar ABCs first published a white paper that provides a basic explanation of the cause of these fires, followed by an outline of a limited research plan designed to develop solutions.

Then, Solar ABCs conducted research to determine the conditions where existing ground-fault protection is inadequate. This research included both engineering analysis and field evaluations of existing installations. Solar ABCs engaged stakeholders throughout the project who developed a matrix of possible mitigation measures. Solar ABCs published a report that contains portions of a Sandia National Laboratories (Sandia) technical report that investigated ground fault detection deficiencies associated with faults occurring on the grounded current-carrying conductor (CCC) of a photovoltaic (PV) power system. The Sandia work analyzed the effectiveness of PV system fault detection methods for a range of ground fault fuse sizes to determine the optimal fuse size for improving ground fault detection sensitivity.

Finally, Solar ABCs published a final report that includes results of field research conducted to characterize basic array wiring impedance properties and their effects on ground fault detection, circuit modeling, and analyses of high and low impedance faults that may occur throughout the array. The report includes major mitigation strategies and equipment retrofit options.

Grounding
Grounding consistently placed near the top of the Solar ABCs gap analysis priority lists.

Solar ABCs published three reports on ground of PV modules and systems. The first focused on the existing state of affairs associated with module/system grounding, problems experienced in the field, issues with existing standards, and proposals floated to date to improve the existing standards. The second includes results from substantive testing performed by UL on accelerated aging of grounding components via corrosion mechanisms. The second report also documents recommendations for changes to current testing requirements for grounding equipment, based on conclusions developed by the UL 1703 STP subcommittee focusing on module frame grounding. The third report recommends adopting PV module corrosion test protocols published by the IEC TC82, which better address module-specific issues than the more general ASTM and IEC standards.

Solar ABCs published a report addressing the requirements for electrical grounding of photovoltaic (PV) systems in the United States. The report explains what grounding is and defines different types of grounding. It also describes existing National Electrical Code® (NEC®) grounding requirements in some detail, explains

the basic System Grounding of grounding PV equipment and systems, and notes the U.S. organizations responsible for developing and publishing grounding and safety standards.

Local Regulations
Solar ABCs examined deployment barriers posed by cumbersome or ambiguous local permitting fees and processes. In response to this analysis, Solar ABCs developed two study reports. The first is a review of solar access law and provides model statutes for use by state and local governments.

The second is a recommended expedited permit process for small photovoltaic systems. The expedited permit process simplifies the structural and electrical review of a small PV system project and minimizes the need for detailed engineering studies and unnecessary delays. In addition to the report, Solar ABCs published fill-in forms for use by local jurisdictions. The Solar ABCs process has been adopted in full or part by many jurisdictions across the country and is the basis for recent work across the country to streamline PV permitting.

Wind Load Calculations
Solar ABCs developed an approach for application of American Society of Civil Engineers (ASCE/SEI) Standard 7-05 "Minimum Design Loads for Buildings and Other Structures" to PV array installation.

Maintenance and Inspection
Solar ABCs published a preliminary O&M guide is intended to help qualified individuals safely maintain and inspect PV systems. It identified the recognized major safety requirements during PV servicing and repair and provides details for a number of O&M tasks. This report serves as an introduction to O&M for PV installations. This introductory report is intended as a bridge until a more comprehensive guide is published and includes practical guidelines for PV system maintenance and options for inspection practices for grounded PV systems.

Accelerated Lifetime Testing
Solar ABCs published a literature review and associated analysis of photovoltaic (PV) field failures, degradation mechanisms and statistics, and available accelerated testing (AT) methodologies. In addition, Solar ABCs published a report detailing a comprehensive long-term multi-step effort required to develop and validate both current and new durability tests and introduces a roadmap to the development of a service life prediction methodology.

Interconnection Standards
Solar ABCs published two study reports on interconnection standards. One examines the four leading small generation interconnection standards that regulators consider when developing state and local procedures. The other examines the external utility disconnect switch and recommends eliminating the requirement for its use.

Net Metering and Interconnection Issues
Solar ABCs published a report discussing the important differences between retail and wholesale photovoltaic (PV) markets and provides examples of policies that have been implemented in the United States in both of these markets.

Solar ABCs conducted a thorough examination of the impact of net-metered solar facilities on non-participating customers' utility rates. The published report puts forward a methodology for the valuation of net energy metering (NEM) focused on best practices. Information in this report will assist state policy makers, utility planners, utility regulators, and all other stakeholders who must evaluate the potential rate impacts of NEM in their states.

Solar ABCs recommended updates to the Federal Energy Regulatory Commission (FERC) Small Generator Interconnection Procedures (SGIP) fast track technical screens. Many stakeholders and subject matter experts contributed to the analysis and helped develop the recommendations.

Solar ABCs supported the activities of state and local offices responsible for, but often unprepared for, the development and execution of statutory regulation governing PV deployment. Solar ABCs representatives spoke at many regulatory, utility, and government meetings.

Advanced Metering Infrastructure
Solar ABCs published a white paper to create awareness of the advancement of automated metering infrastructure (AMI) and how it will affect small distributed generation across the United States.

An Integrated Partnership to Create and Lead the Solar Codes and Standards Working Group

INTRODUCTION

This report describes the multitude of tasks, studies and reports conducted by the working group organized under the DOE Cooperative Agreement DE-FC36-07GO17034. This group and its work came to be known as 'Solar ABCs', and during the progress of this award, Solar ABCs is frequently referenced by others. A website was established to keep the public informed of progress, and as a place to find reports addressing solar codes and standards.

This report documents the tasks undertaken and the reports completed. These are listed as Deliverables under each section. The publications and reports are included as an Appendix to the report.

TASKS PERFORMED

Tasks for this project are organized by group and by project category: *steering committee, project administrator, study areas*, *coordination activities*, *and implementation activities*.

TASK AREA 1: *STEERING COMMITTEE*

The *Steering Committee* will develop the strategic plans that will guide the Solar ABCs. One representative from each project partner plus DOE and the two national laboratories will be represented.

Task 1.1: *Planning Activities*

Objective: The *Steering Committee* will determine the priorities of the Solar ABCs that will guide it through its five-year operation to respond to the needs of the U.S. solar stakeholders in an effective and optimal way.
Task Description: During the first year, the *Steering Committee* will develop a comprehensive Gap Analysis of the current state of the major codes and standards for solar. This will be based on the activities of the working panels and the reports from the one-year study areas. Prioritized guidelines will be generated based on the findings of the Gap Analysis.

Year 1 Gap Analysis

The Gap Analysis was a major project for the Solar ABCs Steering Committee during the first year of the project. Stakeholders provided topics for consideration, the Advisory Committee and Steering Committee refined and prioritized the list of topics, and the Steering Committee developed the final list of high priority Gap Analysis topics.

Solar ABCs was launched with a stakeholder meeting on September 27, 2007 in Long Beach, California. Over 200 people attended this meeting including representatives from the solar industry, utilities, suppliers, and other interested stakeholders. During that meeting, participants learned about the first year activities of Solar ABCs. In addition, stakeholders were asked for their input on gaps or items that need improvement in the codes and

standards processes related to photovoltaics. These suggested topics became the start of the Solar ABCs Gap Analysis Topic List.

Solar ABCs panels held Stakeholder Meetings in December 2007 and January 2008 and received additional suggestions for topics. As the Solar ABCs became known, additional stakeholders submitted proposed topics directly to the Project Administrator.

The Project Administrator compiled the list and sent it to both the Steering Committee and the Advisory Committee for review and discussion. These discussions led to combining topics, adding topics, and reorganizing the way the topics were presented in order to facilitate better review and prioritization

The Advisory Committee and Steering Committee each reviewed and prioritized the Gap Analysis list. Finally, the Steering Committee conducted a day and a half meeting to prioritize the Gap Analysis topics.

The final high priority topics included:

- Standardization of module power rating
- System Energy Performance Standard
- Standards to certify the accuracy of inverter meters
- Accelerated life testing for safety, reliability and durability of modules and the components used in modules
- PV Module frame grounding issues
- Roof-top PV module-specific fire research, testing and ratings systems
- National Fire Safety Guidelines for roof-top PV systems
- Revise building codes to address PV specifically
- Review and suggest updates to FERC interconnection screens
- Rate Impact of Net Metering

Year 3 Gap Analysis

The second Gap Analysis, conducted in Year 3 of the Grant, followed a similar process to the Year 1 Gap Analysis.

This list of potential topics or gaps began with topics suggested during the first Gap Analysis process, but not given a high priority. Also high priority topics identified in the first process, but for which, work as not begun were also added to the list. The final category of topics included topics suggested to the Solar ABCs Project Administrator since the completion of the first Gap Analysis. In the September 2009 Newsletter and at the annual Solar ABCs Stakeholder meeting on October 29, 2009, Solar ABCs requested and received Gap Analysis input from stakeholders.

The Advisory Committee and Steering Committee each reviewed and prioritized the Gap Analysis list. Finally, the Steering Committee conducted a day and a half meeting to prioritize the Gap Analysis topics.

From topics suggested by stakeholders, the Solar ABCs Steering Committee identified the following high priority topics to be addressed.

Highest Priority Topic

- Follow-up Research on Flammability Issues

Second Highest Priority Topics

- Ground Fault Protection Improvements to Prevent Fires
- Standards for PV and Storage
- Connection of PV to the Smart Grid
- Guidelines for Utility Inspections

Third Highest Priority Topics

- Training for Installers and Fire Officials
- Develop operation and maintenance best practice guidelines including periodic safety-targeted inspection programs for Bypass-Diode Failures National Model Fire Guidelines
- Model Building Codes (ICC)
- Extend Expedited Permitting Guidelines to More Small Systems
- Develop Permit Guidelines for Large Systems
- Accuracy of Electro-Mechanical Meters
- Time-of-use Rate Structures

These topics are high priority, but any Solar ABCs will defer any work on the topics until research or work at national labs is complete:

- Inverter Qualification Standard
- Standards for Power Conditioning and DC-DC- Converters
- Standards for High Penetration Solar

Solar ABCs recommends that DOE fund someone to conduct the following task as this task requires more resources than Solar ABCs has available.

- Web-based Code Official Training

The following topics are high priority, but others are already working on the tasks:

- Testing for Firefighter Safety (Underwriters Laboratories)
- Large Generator Interconnection Standards (Federal Energy Regulator Commission)

Year 4 Gap Analysis Update

In 2011, Solar ABCs revised the Year 3 Gap Priority list based on changes in the field since the Year 3 work. The revised priority list follows:

Highest Priority

- Follow-up Research on Fire Rating Issues

Second Highest Priority Topics

- Ground Fault Protection Improvements to Prevent Fires
- Standards for PV and Storage
- Connection of PV to the Smart Grid
- Guidelines for Utility Inspections

Third Highest Priority Topics

- Training for Installers and Fire Officials
- Bypass-Diode Failures/Safety-Targeted Periodic Inspection Programs
- National Model Fire Guidelines
- Model Building Codes (ICC)
- Extend Expedited Permitting Guidelines to More Small Systems
- Develop Permit Guidelines for Large Systems
- Accuracy of Electro-Mechanical Meters (through base funding, no new resources)
- Residential Rate Structures

New Advisory Committee Recommendations

- Universal PV Interface Standards
- PV Connector Standard
- White Paper on the Use of Modules with Embedded Electronics
- Maintenance and Inspection Guidebook

The following topics are recognized as being high priority, but Solar ABCs will defer any work on these topics until research or work at national labs is complete:

- Inverter Qualification Standard
- Standards for Power Conditioning and DC-DC- Converters
- Standards for Installation and Operation
- Standards for High Penetration Solar

Solar ABCs recommends that, if possible, DOE fund the following tasks outside of Solar ABCs as this task requires more resources than Solar ABCs has available:

- Web-based Code Official Training
- Initiative to standardize and streamline permitting

The following topics are recognized as high priority, but other organizations are working on these tasks:

- Testing for Firefighter Safety (UL)
- Large Generator Interconnection Standards (FERC)

Deliverables:
Year 1 Gap Analysis Report
Year 3 Gap Analysis Report
Year 4 Gap Analysis Update

Task 1.2: *Coordination Activities*

Objective: The *Steering Committee* will have responsibility for all decision-making within the Solar ABCs.
Task Description: The *Steering Committee* will set priorities for the Solar ABCs, approve the layout and specification of the Solar ABCs Web page, approve schedules and agendas for regular meetings, provide guidance to the Project Administrator.

The *Steering Committee* started with thirteen voting members and the Project Administrator, who is a non-voting member. The thirteen voting members include one representative from DOE, NREL, and Sandia, one representative from each of the project partners (NMSU, FSEC, IREC, NCSU, BEW, ASU, PowerMark, UL, Brooks Engineering, Sunset

Technologies). Through the grant period first one and then two members from the Advisory Committee were added to the Steering Committee.

Solar ABCs developed a Charter that describes how Solar ABCs and the Steering Committee operate. The goal was to work by unanimous consensus of Steering Committee members. When unanimous consensus was not possible, the chapter defines those items that require two-thirds favorable vote to pass and those that require a majority vote. The Steering Committee adopted the first Solar ABCs charter on July 17, 2007. The chapter was amended four times during the grant period.

The Steering Committee met monthly throughout the grant period. In most years, two of the meetings were in person meetings and the remaining meetings were by conference call. The Steering Committee meetings addressed the following issues:

- Approval of work plans and finals drafts of all Solar ABCs Reports
- Appointment of Advisory Committee members
- Development and prioritization of Gap Analysis Topics
- Reviewed and prioritized new issues as they developed
- Briefings on high priority codes and standards topics
- Review of changes under consideration to PV related codes and standards

In addition, the Steering Committee took the following actions:

- Designated Underwriters Laboratories as Standard Development Organization for *Standard on Nameplate*, *Datasheet and Sampling Requirements of Photovoltaic Modules*
- Approved Solar ABCs recommendations for changes to IEC 61853-1

In response to Stakeholder interest at the first Stakeholder meeting in 2007, the Steering Committee amended the Charter to create an Advisory Committee. The Chair of the Advisory Committee (and later one additional Advisory Committee member) will serve on the Steering Committee. Nominations were solicited though an announcement on the Solar ABCs website, the Solar ABCs Newsletter and e-mail to Stakeholders. For the first election, Solar ABCs received 31 nominations and elected the following 11 people to the Advisory Committee:

Jim Baak, Pacific Gas & Electric (also representing Solar Electric Power Association)
Suzanne Borek, New Jersey Department of Community Affairs
Nick Chaset, California Public Utilities Commission
Adam Detrick, SunPower Corp.
Mark Dougherty, Long Island Power Authority
Smita Gupta, California Energy Commission
Edwin Iracki, DuPont
Tom McCalmont, ReGrid Power
Rhone Resch, Solar Energy Industries Association
Peter Varadi, Consultant
Donald Warfield, BP Solar

The Advisory Committee met quarterly throughout the grant period. The Advisory Committee:

- Reviewed work on high priority topics

- Provided input to Gap Analysis work
- Made recommendations on Solar ABCs projects

In 2009, the Advisory Committee recommended that Solar ABCs address issues with Nationally Recognized Testing Laboratories. This led to a special meeting after the October 2009 Stakeholder Meeting in Anaheim, California. NRTL representatives and industry discussed problems and potential solutions.

Deliverables:
Solar ABCs Charter
Minutes of Steering Committee meetings
Web site functioned throughout project period (provide stats on web site use)
List of Advisory Committee Members
Notes of Advisory Committee meetings

TASK AREA 2: *PROJECT ADMINISTRATOR*
The *Project Administrator* will be responsible for the regular operation of the Solar ABCs and be its primary point of contact to DOE and to solar stakeholders wanting to participate in the activities of the Solar ABCs.

Task 2.1 Coordination *Activities*
Objective: The *Project Administrator* will serve as spokesperson for the Solar ABCs and lead all organized outreach efforts to DOE and stakeholders.
Task Description: The *Project Administrator* will serve as spokesperson for the Solar ABCs. The *Project Administrator* will coordinate with the *Steering Committee* to develop agendas and facilitate SCSWG regular meetings. The *Project Administrator* will coordinate the preparation and delivery of the Gap Analysis to DOE. The *Project Administrator* will prepare quarterly newsletters and distribute these electronically and via the Solar ABCs web page.

The Project Administrator coordinated all aspects of Solar ABCs work including the following items discussed elsewhere in this report:
- Prepared agendas and facilitated discussion at all Steering and Advisory Committee meetings
- Organized and facilitated all Stakeholder meetings
- Organized and facilitated all Solar ABCs webinars
- Produced and distributed all Newsletters and other stakeholder communications
- Coordinated technical review and production steps for all Solar ABCs reports

In addition, the Project Administrator served as spokesperson and contact person for many Solar ABCs liaison activities, including the following:
- Organized Solar ABCs Session at DOE's Solar America Cities 2009 Annual Meeting and Solar ABCs Forum at American Solar Energy Society's Solar 2009 Conference
- Participated in meeting on expedited permitting called by Nick Chaset of the California Public Utilities Commission.
- Participated in ASTM Meeting on June 16, 2009 on their priority standards projects. Their list includes several items also on the Solar ABCs priority list
- Gave presentation on Building Inspector and First Responder Issues and Training at SEPA Utility Solar Conference on July 29, 2009

- Gave presentation on Solar ABCs at International Photovoltaics Reliability Workshop on July 31, 2009
- Participated in ASTM Accelerated Testing meeting on July 23, 2009 and August 4, 2009 and ASTM Grounding meeting on July 28, 2009
- Participated in ASTM Accelerated Testing meeting on August 4
- Met with NREL and Sandia representatives on many occasions to discuss lab coordination with Solar ABCs on various projects
- Participated in September 2, 2009 Market Transformation meeting in Washington, DC
- Participated in several meetings of SEIA Environment Health and Safety Committee
- Developed Solar ABCs session on fire issues for 2009 Solar Power International and invited speakers
- Coordinated issues with California Solar Energy Industries Association and Solar Energy Industries Association
- Organized and facilitated session on Permitting at SolarTech Solar Summit on April 21, 2010
- Assisted with High Penetration Solar Standards Meeting on May 20, 2010 including giving a short presentation on Solar ABCs, chairing a session, and assisting with discussion sessions throughout the meeting
- Developed Solar ABCs session on fire issues for Solar Power International and invited speakers
- Met with consultant for NIST on their solar code plans
- Coordinated various issues many different UL representatives
- Participated in 2011 SolarTech webinar on balance of system issues
- Discussed and reviewed SunRun permitting report with Rob Cahill, SunRun.
- Discussed solar lighting standards with Moneer Azzam
- Discussed permitting issues in western Pennsylvania with Penn Future
- Discussed potential collaboration with Joan Cook of Roofing Industry Committee on Weather Issues (RICOWI)
- Reviewed code and standard abstracts for 2011, 2012 and 2013 Solar Power Conferences
- Gave presentation on Solar ABCs at Interstate Renewable Energy Council Annual Meeting on October 17, 2011
- Attended meeting of UL 1703 Standard Technical Panel on October 25-26, 2011
- Attended meeting of 62109 Harmonization Committee on October 27, 2011
- Gave presentation on Solar ABCs to the Solar Instructor Training Network on January 25, 2012
- Gave presentation on Solar ABCs and code issues Photon Magazine Safety Conference on February 1, 2012 in San Francisco
- Prepared poster on Solar ABCs activities for SunShot Forum.
- Interviewed by Dan Haugen for article in Midwest Magazine
- Gave presentation at World Energy Forum session on wind load issues
- Discussed international codes with representative of IRENA
- Participated in ICC Solar Task Force Meetings
- Reviewed proposals for Fire Protection Research Foundation PV Hazard project
- Discussed local PV regulations with researchers from Virginia Tech University
- Attended meetings with PV Manufacturing Consortium on PV codes and standards issues

- Met with Roger Hill, Bill Brooks, Steve Dwyer, and Andy Rosenthal regarding Sandia work to conduct structural tests to validate structural requirements in expedited permitting processes.
- Gave presentation at PV America East Conference on Solar ABCs activities
- Part of panel interview on codes and standards issues at Solar Central hosted by Renewable Energy World at PV America East Conference
- Prepared and presented poster on Solar ABCs activities at NREL Reliability Workshop
- Met with Mike Whitson, PSG Solar regarding need for O&M standard
- Met with J. Berdner regarding IEEE standard for utilities with high penetration of solar
- Coordinated briefing for Clean States Energy Alliance on June 25, 2010 on PV Module Policy Recommendation.

Deliverables complete:
Quarterly reports on Project Administrator Activities
Quarterly Solar ABCs Newsletter

Task 2.1.1: Subtask 1 – Communications

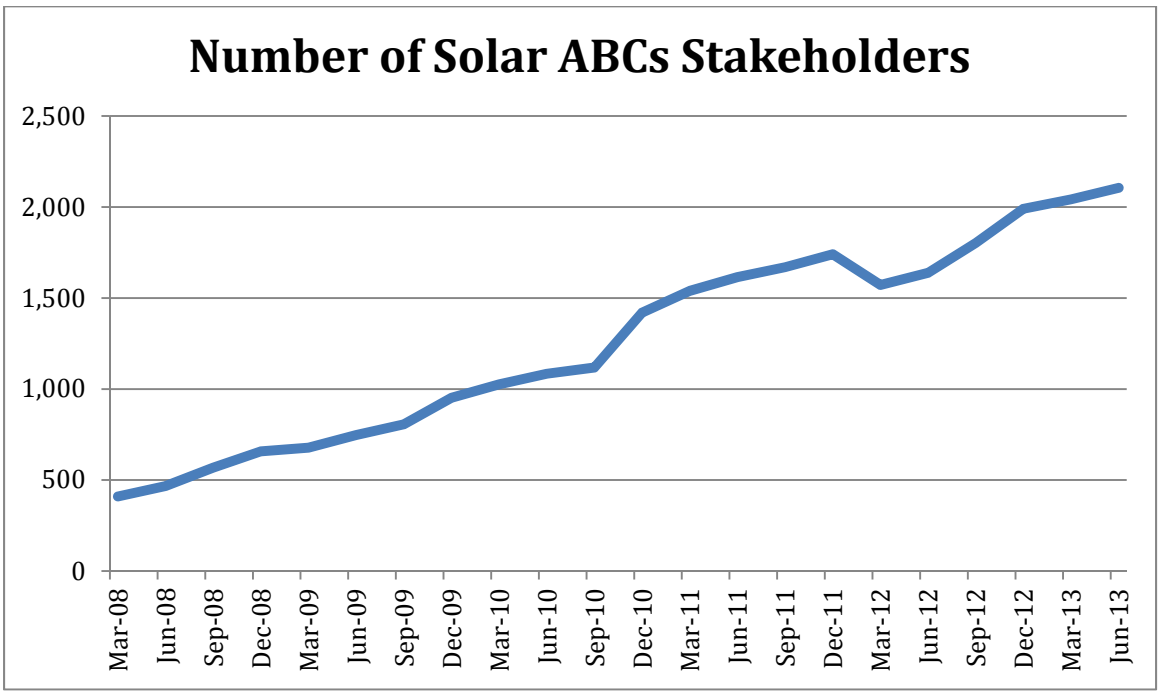
Effective communication of all products and publications of the Solar ABCs is essential to provide stakeholders with the access to the information needed. The communication activities provided by the Solar ABCs will be increased in response to requests from stakeholders and regulators. Solar ABCs will contract with a new communications specialist to lead in disseminating the important information developed under both the existing Solar ABCs contract and this contract modification. Over the performance period, Solar ABC will:

1. Develop a Solar ABCs "brand," easily recognizable for policy makers and other stakeholders to recognize as their first source of information on solar codes and standards issues.
2. Develop and implement communications plans for each product as it is developed.
3. Continue to improve the Solar ABCs website
4. Developing and implementing a plan to increase the number of stakeholder participants from target audiences.

- Developed communications workplan with input from NREL.
- Developed boilerplate language to include in all Solar ABCs publications
- Developed consistent look for all Solar ABCs publications.
- Conducted benchmark study for Solar ABCs web site and developed new architecture and content for site
- In 2011, Solar ABCs launched redesigned web site (Structural and textual changes were made to provide easier navigation, adjusted color of header so that it blends into the background of the page, making the site appear wider without having to reconfigure the pages to be physically wider, and added photos to the About and Codes & Standards sections, new copy added on status of various codes and standards).
- As each report was published, Solar ABCs developed a communications plan tailored to the audience for the report.
- Developed communications strategy and stand-by press release on Flammability Testing Draft White Paper.

Solar ABCs Stakeholders and Quarterly Newsletter

The number of Solar ABCs Stakeholders grew consistently and steadily throughout the grant period showing strong interest in Solar ABCs events and products. Throughout the grant period, Solar ABCs distributed a quarterly newsletter to stakeholders to provide an update of recent Solar ABCs reports, activities, and discussion of other related PV codes and standards activities.



Solar ABCs Annual Stakeholder Meetings

The Solar ABCs held annual meetings to provide all interested PV stakeholders with an update and review of all major Solar ABCs projects and other activities undertaken in the preceding year. The Solar ABCs scheduled its annual stakeholder meeting to coincide with the annual Solar Power International conference as the best way to attract and increase attendance. The Solar ABCs promoted these annual stakeholder meetings through email campaigns which included several "Save the Date" and "Register Now" emails. Annual stakeholder meetings were also promoted through feature stories posted on the Solar ABCs website and the Solar ABCs Quarterly newsletter. Below is a chart with the attendance numbers for the annual Solar ABCs stakeholder meetings. The meeting agendas and presentation slides were reported to DOE in quarterly reports.

Year	Date	Location	Attendance
2007	September 27	Long Beach, CA	192
2008	October 17	San Diego, CA	113
2009	October 30	Anaheim, CA	117
2010	October 15	Los Angeles, CA	155
2011	October 21	Dallas, TX	121
2012	September 14	Orlando, FL	116
2013	July 11	San Francisco, CA	120

Media Outreach Activities and Results

This section provides the results of media outreach activities conducted by Solar ABCs. The Solar ABCs issued press releases announcing key study reports to a list of targeted media in order to increase visibility and ultimately increase access to Solar ABCs' work products by stakeholders. Below is a list of some of the organizations that published articles or other information received and distributed through the Solar ABCs press releases:

- AltEnergy Mag
- City of Cape Coral, FL
- City of Lancaster, CA
- City of Seattle
- CNBC
- DSIRE Solar Portal
- EDC Magazine
- EERE News
- Energy Efficiency & Technology
- Energy EnvirFinland
- The Free Library
- Heritage Solar
- InterPV
- IREC
- Kansas Corporation Commission
- Midwest Energy News
- Mira Costa College
- National Roofing Contractors Association
- Network for New Energy Choices
- New Energy Choices
- New Mexico Energy
- The New York Times
- NRCA
- NREL's NCPV Hotline
- Power outlet
- Renewable Energy World
- Quality Insider
- SEIA
- Solar America Cities
- SPEER – South-central Partnership for Energy Efficiency as a Resource
- States Advancing Solar
- Sustainable Facility eNews
- University of Illinois
- Vote Solar Initiative

It is important to note that these press releases were developed to specifically to increase stakeholders awareness of available Solar ABCs reports and the success of this effort is reflected in the overall newsletter, website and the annual stakeholder meeting statistics.

Website Activity and Statistics

The original 2007 Solar ABCs website was redesigned and launched in October 2011. Therefore the website traffic statistics for this report will include data from October 1, 2011

through March 31, 2013. The Solar ABCs uses Google Analytics for website data collection, which are collected from tagged pages on the Solar ABCs website.

The Solar ABCs created a publication webpage for each study report, press release, stakeholder webinar, or other PV current issues to provide a centralized source of information regarding PV codes and standards and ultimately increase stakeholder access. The Solar ABCs website traffic increased by 35% from 2011 to 2012. Below is a summary of the website statistics:

Total Website Traffic (average unique page views per month)
2011: 1,988
2012: 2,694
2013: 3,139

Website Views of Solar ABCs Reports by Year

Report	**2011**	**2012**	**2013**	**Total**
Expedited Permit Process	16,029	32,714	32,349	81,092
Grounding PV Module Reports	1,072	2,811	1,472	5,355
Wind Load Calculations	2,516	1,829	948	5,293
Comparison of Four Leading Small Generator Interconnection Procedures	1,508	1,710	1,213	4,432
Impacts on PV Installations of Changes to the 2012 International Codes	930	1,978	1,221	4,129
Solar Access Law	1,468	1,039	630	3,137
Ground-Fault Protection Blind Spot Reports		1,606	1,197	2,803
Understanding the CAL FIRE PV Installation Guideline	977	847	469	2,293
A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering		1,403	496	1,899
Utility External Disconnect Switch	933	568	395	1,896
PV Module Power Rating per IEC 61853-1		933	893	1,826
Flammability Testing: Interim Report	953	462	216	1,631
Policy Recommendation: PV Module Power Rating Requirements	710	459	187	1,356
A Proposed Standard for: Nameplate, Datasheet, and Sampling Requirements		888	321	1,209
Recommended Standards for PV Modules	594	341	168	1,103
Updated Recommendations for FERC SGIP Screens	684	271	126	1,081
Sustainable, Multi-Segment Market Design for Distributed Solar Photovoltaics	590	223	128	941
PV System Grounding			895	895
Potential Impacts of Advanced Metering Infrastructure	559	162	137	858
Validation of Draft IEC 61853-2 Standard: Angle of Incidence Effect on PV Modules			548	548
Accelerated Lifetime Testing of PV Modules			83	83

Validating PV Module Durability Tests			75	75
PV System Operations and Maintenance Fundamentals			29	29

Deliverables:
Brand Report
Report communication plans with results – sample included

TASK AREA 3: *STUDY AREAS*

The study areas and related activities are described in Task 3. The study areas provide detailed analysis of issues important to developing PV codes and standards. All results will be delivered as study area reports and will also be used to develop the Gap Analysis that is also due at the end of year 1. Study areas shall be coordinated with panel areas in Coordination and Implementation areas stated below (Task Areas 4 and 5) to the extent that redundancies can be prevented and work product leveraged.

Task 3.1: *The Interconnection Standards Study Area and Panel*

Objective: The *Interconnection Standards Study Panel* will perform a one-year examination of critical interconnection issues. The annual report will be delivered to the *Project Administrator* and its results will figure into the Gap Analysis process.
Task Description: The study panel will examine existing utility interconnection screens (institutional forms and processes that allow approval of interconnect requests) adopted by local jurisdictions and the perceived roles that these screens have played in facilitating PV deployments. This panel will also determine the usefulness of the external utility disconnect switch that is often required by local jurisdictions but equally often described as superfluous and unneeded.

Solar ABCs held two Stakeholder Meetings (on December 14, 2007 and March 24, 2008) to obtain input for the interconnection study reports. Solar ABCs published the following two interconnection study reports.

Comparison of the Four Leading Small Generation Interconnection Procedures
Authors: Jason Keyes and Kevin Fox, Interstate Renewable Energy Council
The report reviews four sets of interconnection procedures (FERC's Small Generator Interconnection Procedure, California Rule 21, MADRI and IREC) that regulators often consider when developing state and local procedures. As a framework for review, the report uses the grading criteria developed by the Network for New Energy Choices. The report concludes that each of the four sets of procedures present a suitable framework for effective regulations, through the authors find that the Interstate Renewable Energy Council's Procedures provide the most comprehensive model.

Utility External Disconnect Switch: Practical, Legal, and Technical Reasons to Eliminate the Requirement
Author: Michael Sheehan, Interstate Renewable Energy Council
The report documents the safe operation of photovoltaic systems without a utility external disconnect switch in several large jurisdictions. It explains the rationale for eliminating the switch.

Deliverable complete:
Study Report: Comparison of the Four Leading Small Generator Interconnection Procedures Report
Study Report: Utility External Disconnect Switch
Created narrated PowerPoint presentation on Utility External Disconnect Switch Report

Task 3.2: ***The Net Metering Study Area and Panel***

Objective: The *Net Metering Study Panel* will perform a one-year examination of critical net metering issues. The annual report will be delivered to the *Project Administrator* and its results will figure into the Gap Analysis process.
Task Description: The study panel will perform a comprehensive study of the economics of net metering in competitive economic markets. The benefits of net metered PV for utilities will be explored. The study will assess how current methods of allocating distribution costs for ratemaking purposes impact the deployment of net metered PV. The study will also investigate the levels of PV penetration that may be reached without impacting grid stability. Lastly, the study will examine the relationship between demand charges and demand ratchets and how net metering may help large industrial customers reduce demand charges.

Solar ABCs published the following report:

Impact of Advanced Metering Infrastructure on Small Distributed Generation
This white paper's intent is to create awareness of the advancement of automated metering infrastructure (AMI) and how it will affect small distributed generation across the United States. The white paper will identify issues on this topic. Addressing known issues now, while AMI is in its early stages of adoption and deployment, will give legislators, regulators, and utility personnel time to revise current policies and establish new ones.

Deliverable:
Study Report: Potential Impacts of Advanced Metering Infrastructure on Renewable Energy Policy

Task 3.3: ***The Local Codes and Standards Study Area and Panel***

Objective: The *Local Codes and Standards Study Panel* will perform a one-year examination of many deployment barriers posed by cumbersome or ambiguous local permitting fees and processes. The annual report will be delivered to the *Project Administrator* and its results will figure into the Gap Analysis process.
Task Description: The study panel will perform a comprehensive study of the permitting requirements found in several jurisdictions that have been successful in promoting solar (including both PV and water heaters) while requiring low or no fees, concise procedures, and short timeframes. In addition, the study panel will develop model building codes that promote the installation of PV in new or existing buildings. Lastly, the study panel will develop lists of restrictive covenants that have been adopted by local governments that inhibit PV deployments and propose resolutions to these restrictive regulations.

The panel held Stakeholder meetings on December 17, 2007 and March 25, 2008 to receive input for the reports under development. Solar ABCs publish three reports related to this task.

A Comprehensive Review of Solar Access Law in the United State: Suggested Standards for a Model Statute and Ordinance
Author: Colleen Kettles, Florida Solar Energy Center
The report documents legal issues for solar access and solar rights, and provides model statutes for use by state and local governments.

Expedited Permit Process for Small Photovoltaic Systems
Author: Bill Brooks, Brooks Engineering
This report presents an Expedited Permit Process for small PV systems. The term "expedited permit process" refers to an organized permitting process by which a majority of small PV systems can be permitted quickly and easily. It is not intended to apply to all types of PV systems. The expedited permit process is intended to simplify the structural and electrical review of a small PV system project and minimize the need for detailed engineering studies and unnecessary delays.

An update to the report was published in 2011. This revision updated ASHRAE temperature tables with newly available data and created an introductory page to the mapping tool used with the Expedited Permit Process and made some minor changes to the mapping tool itself. The revision also added a sample electrical diagram for microinverters and ac modules.

Hosted stakeholder webinar on revised report on September 25 attended by 159 stakeholders.

***Wind Load Calculations for PV Arrays*.**
Authors: Colleen O'Brien, BEW Engineering and Stephen Barkaszi, Florida Solar Energy Center
The report describes an approach for application of American Society of Civil Engineers (ASCE/SEI) Standard 7-05 "Minimum Design Loads for Buildings and Other Structures" to PV array installation.

Deliverables complete:
Study Report: Expedited Permit Process for PV Systems (and Revisions 1 and 2)
Study Report: A Comprehensive Review of Solar Access Law in the United States
Study Report: Wind Load Calculations for PV Arrays
Participated in meeting with SolarTech on December 3, 2009 on ways to improve permitting for solar installations
Created narrated PowerPoint presentation on Solar Access Report

Task 3.4: *The Product Standards Study Area and Panel*

Objective: The *Product Standards Study Panel* will perform a one-year, comprehensive examination of two major technology areas, PV cell performance standards and concentrating PV safety standards. The annual report will be delivered to the *Project Administrator* and its results will figure into the Gap Analysis process.
Task Description: The study panel will develop a cell performance standard that can pre-qualify PV cells to make them available as alternative components in PV modules qualified for construction with other cells. The new standard will support the present IEC guideline, *IEC 61215/61646, Retesting Guideline* for required testing of cells when they are changed

within existing qualified module designs. This study panel will also investigate the issues related to recommended standards for PV modules and systems.

Crystalline Silicon Terrestrial Photovoltaic Cells: Supply Chain Prequalification Specification.
Author: Govindasamy TamizhMani, Arizona State University
The report provides background and recommends standard language for supply chain prequalification specifications.

SEMI convened a meeting to write a standard for procurement of solar cells based on the Solar ABCs report (May 13 at Arizona State University)

Photovoltaic Module Power Rating per IEC 61853 (Draft) Standard: A measurement repeatability study under natural sunlight
Author: Govindasamy TamizhMani, Arizona State University

In 2008, the Concentrator PV standards committee of IEC (IEC/TC82/WG7) initiated a large international effort to develop "Concentrating PV Safety" standard. Because of this activity, a Solar ABCs report on this subject would have been of marginal value. Instead the second report above was done instead.

Deliverables:
Study Report: Crystalline Silicon Terrestrial Photovoltaic Cells – Supply Chain Procurement Specification Guideline Report
Solar ABCs Policy Recommendation: Recommended Standards for PV Modules and Systems

TASK AREA 4: *COORDINATION ACTIVITES*

Tasks for the *Coordination Activities* are designated for the five *Coordination Activity Working Panels*. All activities and tasks are designed to enable communication and planning across the different codes and standards setting processes addressed by each panel. All of these activities and tasks are designed to be implemented in a regular way throughout the full five year project period. This sustained effort will support the timely introduction of new technologies as they occur and the overall growth of PV deployment to new sectors of the energy market.

Task 4.1: *The Building Electrical Codes Working Panel*

Objective: The *Building Electrical Codes Working Panel* centers its activities and deliverables around Article 690 of the National Electrical Code (*NEC*). Improved coordination and outreach of topics related to this important code were achieved through the actions of this working panel than were available prior to Solar ABCs implementation. The panel included representation from the building community and from the DOE Buildings Program. The bulk of the work of this panel was implemented under the task description National Electrical Code Development (below).

National Electrical Code Development

Solar ABCs, in conjunction with the PV Industry Forum, provided a forum for proposals, discussion, and develop of recommendations for the revisions to the National Electrical Code.

For the 2011 NEC code cycle, Solar ABCs:

- Developed 6 drafts of proposed code changes. The drafts were circulated via e-mail to the PV Industry Forum and interested Solar ABCs stakeholders were also posted on the Solar ABCs web site for comment.
- The Building Electrical Code Panel held a Stakeholder Meeting on September 24-25, 2008 in Albuquerque, NM. The Stakeholders discussed Draft 6 of the NEC Proposals. The results of the discussion will be reflected in the Near Final Draft of the proposals to be released in the next quarter.
- In January 2009, Brooks Engineering was invited to participate in an NEC meeting as the alternate voting member to Ward Bower, the Solar Energy Industries Association (SEIA) appointed voting member of the National Electrical Code®, Code-Making Panel 4 (CMP4). CMP4, which oversees Article 690 of the NEC, held the meeting January 12-14, 2009, in Hilton Head, South Carolina.

- Bill Brooks of Brooks Engineering was appointed to the National Electrical Code, Code Making Panel 4, by the Solar Energy Industries Association in the fall of 2008. As part of the responsibilities of that group, Brooks Engineering participated in three days of meetings in Redondo Beach, California to review and discuss the comments on proposals submitted during the public comment period. During the 3-day meeting, Brooks Engineering developed a detailed powerpoint presentation detailing an important proposal for the PV industry that had been rejected in the first round of reviews in January of 2009. The Code Making Panel was receptive to the material but elected to hold action on the proposal until the next code cycle. A task group will be formed in 2011 to review the proposal in detail and bring a formal recommendation for the 2014 code cycle. Other proposal important to the PV industry were guided to approval by Ward Bower of Sandia National Labs and Brooks Engineering.

2014 NEC Code Cycle

- Brooks participated in the 2014 National Electrical Code (NEC) PV industry task group meeting held on September 8-9, 2011 and hosted by New Mexico State University in Las Cruces, New Mexico.
- Brooks finalized the development of proposals to the 2014 NEC on behalf of the NFPA task force on firefighter safety in PV systems. These proposals were submitted to NFPA for the 2014 NEC code cycle.
- Brooks attended the NFPA Report On Proposals meetings on January16-21, 2012 in Hilton Head, South Carolina
- Brooks began to outline the implications of the 2014 NFPA Report On Proposals for the National Electrical Code due to be produced by the end of the second quarter.

- Organized stakeholder meeting on August 27, 2012 to review the Report on Proposals and identify needed comments on the 2014 National Electrical Code. Meeting attended by 33 people on-site and up-to 52 additional people on webex. Resulted in xx task forces to develop responses to proposals in the NEC.

4Q12

- Brooks organized and facilitated several meetings with SEIA representatives, PV industry representatives, and the NFPA CMP4 Task Force on Firefighter Safety.
- Brooks submitted comments to the National Electrical Code in October to address concerns by the solar industry about various proposal actions by the Code Making Panel 4 (CMP4) on key issues to the industry. Among these concerns are issues related to the newly proposed 690.12 on Emergency Shutdown of PV circuits.
- Participated in meeting of CMP 4 Task Force on 690.12 and organized meeting for stakeholders to develop final comment language on 690.12

1. SWTDI engineers participated in the post-fire analysis of two large PV system fires during this reporting period. In one case, the Bakersfield fire, identification of the events which led to this fire may indicate that a revision is necessary to the NEC. The fire, which by most accounts was initiated by damage resulting from workmanship problems, spread because strings had been bussed and then the bussed cables fused in accordance with the NEC. Unfortunately, fault current from a failed string was then insufficient to blow this large fuse. An internal study will be undertaken to determine if the code should require individual strings to be fused differently in order to prevent this situation. (2008-2009?)

Presentations and Workshops

- 4Q10: NMSU provided technical workshops covering issues of PV and the NEC specifically written for electrical inspectors in three venues during the quarter: Arizona Building Officials Conference (Phoenix, 165 attendees), Pennsylvania building officials meeting (Lancaster, 85 attendees), Arizona building officials (2 separate workshops in Phoenix, 65 attendees for the first, 75 attendees for the second).
- 2Q11: NMSU provided technical workshops covering issues of PV and the NEC specifically written for electrical inspectors in three venues during the quarter: Arizona Building Officials Conference (Phoenix, 165 attendees), Pennsylvania electrical inspectors meeting (Lancaster, 85 attendees), Arizona electrical inspectors and utility engineers (2 separate workshops in Phoenix, 65 attendees for the first, 75 attendees for the second).
- Brooks represented Solar ABCs and presented at the NFPA NEC Alternative Energy Symposium in Atlanta, Georgia on December 6, 2011. The presentation focused on activities of the NFPA task force on firefighter safety in PV systems that Brooks is chairing.
- Brooks represented Solar ABCs and present at the Photon International conferences on PV Safety and Inverters on February 1-2, 2012
- Brooks participated in two working group meetings after PV America that were hosted by SolarTech on March 22. The first meeting discussed ways to improve the

codes and standards for microinverters and the second meeting discussed similar issues related to string inverters.

- 2Q12: PV/NEC presentations were made in Hartford CT, Boston MA and Phoenix AZ Average attendance was about 55 people per presentation

2. NMSU engineers provided critical review of the bonding and grounding suggested revisions to the UL1703 standard that will be discussed at the UL 1703 STP meeting in November
3. NMSU engineers also consulted with UL and SNL on proposed revisions and standard harmonization related to modules and use of polymers.

4Q10

4. NMSU engineers participated in the UL1703 standard technical panel meeting in December. John Wiles (NMSU) was placed in charge of an STP working group tasked with comparing the specifications of the NEC to those of UL 1703 for the purpose of identifying potential conflicts between the two. A report from this working group will be delivered at the end of January 2011.
5. NMSU hosted the annual meeting of the NABCEP exam committee. The committee designs and produces a new NABCEP exam each year for use throughout the country in certifying PV installers.

2Q11

6. NMSU engineers participated in the UL1703 Standards Technical Panel (STP) meeting in December. John Wiles (NMSU) was placed in charge of an STP working group tasked with comparing the specifications of the NEC to those of UL 1703 for the purpose of identifying potential conflicts between the two. Proposals for modifying UL 1703 from this working group were submitted to the STP in June 2011.
7. NMSU engineers participated in the UL 1741 Standards Technical Panel STP) meeting held in April 2011. John Wiles (NMSU) was placed in charge of an STP working group tasked with comparing the specifications of the NEC to those of UL 1741 for the purpose of identifying potential conflicts between the two. Proposals for modifying UL 1741 from this working group will be submitted to the STP in August-September 2011.
8. NMSU engineers are also participating in UL Standards Technical Panels for DC PV Arc Fault Circuit Interrupters, PV module racking systems, and PC Cables
9. NMSU hosted a meeting of the NABCEP exam committee. The committee designs and produces two new NABCEP exams each year for use throughout the country in certifying PV installers.

2Q12

10. Substantial changes that were proposed by SWTDI engineers for UL 1703 were approved and published on 8 May 2012 These changes clarify the required content with respect to mounting, grounding and subsequent NEC calculations of the PV module installation manual and require that the NRTLs listing PV modules to UL 1703 carefully review and approve all instructions in the manual--something that is not currently being required

11. A similar proposal has been submitted to the UL 1741 STP and is being circulated for comment. It will also require many clarifications in the instruction/installation manuals for inverters and also require that the NRTLs fully review such manuals for compliance with NEC requirements
12. Membership is active on the UL Standards Technical Panels for modules, inverters, racks, connectors and cables
13. Two conference calls were held to discuss NABCEP Exam test questions

3Q12

1. Facilitated follow-up conference call meeting on 690.12 recommendation on September 28, 2012

Deliverables complete:
Developed proposed changes for 2011 National Electrical Code
Stakeholder Meeting June 5-6, 2008, Golden, CO
Stakeholder Meeting September 24-25, 2008, Albuquerque, NM
Stakeholder Meeting, September 8-9, 2011, Las Cruces, NM
Stakeholder Meeting, August 27, 2012, Northbrook, IL
Stakeholder Meeting on Article 690.12, September 28, 2012, Conference Call
Annual Solar ABCs Stakeholder Meeting, September 27, 2007, Long Beach, CA
Annual Solar ABCs Stakeholder Meeting, October 17, 2008, San Diego, CA
Annual Solar ABCs Stakeholder Meeting, October 30, 2009, Anaheim, CA
Annual Solar ABCs Stakeholder Meeting, October 15, 2010, Los Angeles, CA
Annual Solar ABCs Stakeholder Meeting, October 21, 2011, Dallas, TX
Annual Solar ABCs Stakeholder Meeting, September 14, 2012, Orlando, FL
Annual Solar ABCs Stakeholder Meeting, July 11, 2013, San Francisco, CA
Participated in meetings of NFPA Code Making Panel 4 for the National Electrical Code

Presentation to TPP Participants, August 2007 at NREL
Have chart with TPP participation in first year of stakeholder meetings

Task 4.2: *The Product Safety Working:*

The Product Safety Working Panel centers on planning, coordination, and outreach tasks related to UL standards, particularly UL 1703 and UL1741. The working panel will support research and refinements into the specific UL standards.

Stakeholder Outreach

- In response to a specific request from CALSEIA, UL met with Sue Kately, the Executive Director and members of their industry group to discuss areas of specific interest and concern. A meeting was held on March 20, 2008 to refine the discussion topics and provide the output to Solar ABCs for consideration. This information will lead to revision of UL's Solar ABCs project tasks and deliverables. Discussions topics include:
    - Listing requirements for products installed using mounting brackets different than those used during the UL1703 test.
    - Listing requirements for grounding lug.
    - UL White book sentence regarding the possible effect a rack-mounted PV system of one fire class rating on the fire resistance and/or class rating of the roof material.
- Product Safety Panel Stakeholder Meeting held on July 9, 2008.

PV AFCI Research

- UL R&D established a PV AFCI Ad Hoc Group as part of the effort to develop PV AFCI requirements.
    - A UL1699 PV AFCI meeting was held April 7-8, 2009. Fifteen guests attended the meeting, including AFCI manufacturers, PV manufacturers, university and government researchers, and other knowledgeable consultants in addition to UL technical staff.
    - UL PV AFCI Ad Hoc Meeting held on November 30 and December 1, 2010
- UL conducted the following research:
    - Contacted a manufacturer in the aerospace industry that produces 28Vdc and 42Vdc AFCIs and discussed the potential of applying this technology to higher voltage PV arrays.
    - UL is attempting to quantify the available PV inverter maximum fault current contribution to PV string faults. This information is needed to define the PV fuse fault current rating and tests.
    - Conducted initial PV arc fault metering measurements in an effort to identify specific parameters associated with PV arcing faults. High frequency, high resolution metering equipment with filtering capability will be necessary to make these measurements. UL found it very easy to produced constant arcs with only the output of a single run of the mill crystaline PV module. This was duplicated with two different configuration modules.
    - Conduct a literature search of national and international PV documents to characterize issues related to PV AFCI needs.
    - Used a PV rooftop test station at UL's Northbrook facility for tests to support pass/fail criteria for the testing requirements in the next draft of the Outline. Testing possible PV arc hazards
        - Arc fault detection tests,
        - Unwanted tripping tests,
        - Operation inhibition tests
    - UL studied Arc Signature measurements including impact of common PV circuit plastic materials in close proximity to the arc.
    - Received report from Consultant (Jerry Hastings) on Arc Signature measurements including impact of common PV circuit plastic materials in close proximity to the arc.
- UL proposed the following standard and code changes:
    - The maximum fault current available in most PV circuits is sourced from the capacitor banks in the PV inverters. To address this issue, UL has proposed a revision to UL1741 STP to limit inverter backfeed fault current contribution to less than 10,000 amps to coordinate with the fuse proposal.
    - Issued a draft Outline of Investigation for the PV AFCI (Subject 1699B), received comments and revised the document based on input received. Subject 1699B Outline of Investigation for PV DC Arc-Fault Circuit Protection has been completed was published on April 29, 2011.
    - UL made a proposal to require PV AFCIs Code Making Panel 4, CMP4 for the 2011 National Electric Code NEC. The proposal was accepted by the panel with the understanding that the requirements will be published and Listed PV AFCI products will be commercially available by the publication date of the 2011 NEC.

    - UL wrote requirements for compliance with the 2011 AFCI requirements in the 690.11, 2011 NEC.
    -
- Conducted the following outreach efforts:
    - Gave PV AFCI presentation and SAI project update to US TAG meeting in Phoenix on September 25th.
    - Presented the Development of AFCI Requirements for PV Systems to the IEEE 37th Photovoltaic Specialist Conference in Seattle, WA, during the week of June 20th.
- PV AFCI project is complete, but UL continues to gather AFCI data from the STP efforts and from experience gained from applying the tests during product certifications.

<u>UL1703 and IEC61730</u>

- A UL1703 Standards Technical Panel proposal was accepted to revise the existing UL1703 PV Module Grounding and Bonding requirements. This revision will help to clarify the existing requirements and further reduce the grounding requirement gap between the NEC and UL1703. It is proposed that the results of this work will be directly incorporated into the IEC 61730 national differences within the UL61730 proposal.
- The UL61730-1 draft proposal has been sent to the UL1703 STP for comment via the on line Collaborative Standards Development System (CSDS). The UL61730-2 draft is presently in the UL Standards Department being prepared for distribution the UL1703 STP early next week. These drafts include US national differences and corrections for mistakes in the original IEC documents. These will be proposed as revisions to the IEC document to further harmonize the US and International documents.
- UL received comments on both the UL61730-1 and UL61730-2 draft proposals. A UL1703 STP task group meeting was held to review and address these comments in preparation for the STP ballot. The task group meeting was productive and many of the proposed US national differences will be proposed at the IEC WG2 meeting in Korea the week of Oct 6th as revisions to the IEC 61730 documents. Upon return from the IEC meeting the drafts will be prepared for STP ballot through the UL Collaborative Standards Development System (CSDS).
- The STP comments on both the UL61730-1 and UL61730-2 drafts were proposed at the IEC WG2 meeting in Korea the week of Oct 6, 2009 as revisions to the IEC 61730 documents. Most of the revisions were well received and expanded upon. Some of the US proposed revisions were considered IEC corrections so an IEC Corrigendum was prepared to formally revise IEC 61730-1 and IEC 61730-2 and submitted to IEC TC 82 Secretary on December 23, 2008. The combined US / IEC revisions will be combined in the UL 61730 ballot drafts and will be proposed to the UL1703 STP and they will also be sent to the IEC TC82 WG2 as revisions to IEC 61730 standards.
- Held three international IEC PV Plastics teleconferences to work through IEC 61730-1 PV plastics challenges. This work is in preparation for in person meeting tied to IEC TC82 WG2 meeting in May 2010. The result of this work will be to develop an applicable set of requirements for PV plastic materials that can either be included in or referenced from IEC 61730-1. This resultant work will also address many of the same issues that are holding up US adoption of the IEC standard.
- Working with NREL to develop Module test programs to evaluate complete modules for long-term polymeric properties.

- Working through IEC comments and revisions on previous IEC 61730 drafts in preparation for IEC WG2 meeting in May 2010.These solutions will be proposed to the IEC WG2 as a revision to IEC 61730-1.
- Held three international IEC PV Plastics teleconferences in 2010 to work through IEC 61730-1 PV plastics challenges
- Held a large in person meeting for the last 1.5 days of the IEC TC82 WG2 meeting in May 2010. We now have 65 members participating in the seven PV polymeric task groups, Steering Committee, Weatherability, Edge Sealants, Backsheets, Adhesives, Partial Discharge, and Encapsulants. The result of this work will be to develop an applicable set of requirements and tests to which PV plastic materials can be characterized as well as be included in or referenced from IEC 61730-1. This resultant PV polymeric work is addressing many of the same errors, problems and issues that have delayed the US adoption of the IEC standard.
- Working with NREL to develop module test programs to evaluate complete modules for long-term polymeric properties
- Working with NREL to develop module creep tests to evaluate the hazards associated with creep and flow of polymeric materials at high operating temperatures that could lead to mechanical failures, high voltage shock hazards and stress and strain on critical electrical connections which could result in arc fault fires
- Received request to create bi-national version of IEC 61730 for both the US and Canada to minimize differences in product certifications in North America.
- Working with NREL to develop module test programs to evaluate complete modules for long-term polymeric properties
- Working with NREL to develop module creep tests to evaluate the hazards associated with creep and flow of polymeric materials at high operating temperatures that could lead to mechanical failures, high voltage shock hazards and stress and strain on critical electrical connections which could result in arc fault fires
- UL held eight international IEC PV Plastics teleconferences to work through IEC 61730-1 PV plastics challenges.
- UL continued to address comments on IEC 61730-1 draft from the IEC TC82 WG2 meeting in Baltimore in May 2010.
- UL is working with NREL to develop module test programs to evaluate complete modules for long-term polymeric properties.
- UL is working with NREL to develop polymeric material deformation tests. This work included comment resolution from the UL1703 STP comments on the module creep tests proposal. This work is to evaluate the hazards associated with creep and flow of polymeric materials at high operating temperatures that could lead to mechanical failures, high voltage shock hazards and stress and strain on critical electrical connections which could result in arc fault fires.
- Participation in multiple UL1703 STP Materials Task Group teleconferences with the objective of finalizing a proposed revision to UL1703 to address this issue.
- Participation in the IEC PV Backsheet Task Group to develop the NWIP.
- Participation in teleconferences regarding encapsulants.
- Participation in the UL1703 STP International Harmonization Committee to develop a harmonized version of the US standard with IEC61730 standards.
- Reforming a new task group to revise the CD draft for presentation in Oslo, Norway, during the 4th quarter of 2012.
- UL hosted a 61730-1 US team meeting to address the 61730-1 2nd Edition proposal.

- Participation in the UL1703 STP Materials Deformation Task Group with the objective of finalizing a proposed revision to UL1703 to address this issue.
- Participation in the TC 82 WG2, 3 and 6 meeting in Shanghai, China during May, 2011.
- Held task group teleconferences to revise IEC 61730-1 creepage and clearance section to be consistent with IEC 60664.
- Revised 61730-1 edition 2 draft to include recent task group work product and to address previous WG2 comments from previous IEC meetings. Presented updated draft to WG2 and received additional comments on draft.
- Participation in the TC 82 WG2, 3 and 6 meeting in Montreal, Canada during September, 2011.
- Held task group numerous teleconferences to revise IEC 61730-1 creepage and clearance section to be consistent with IEC 60664. UL performed polymeric characterization tests including, but not limited to, CTI and flame tests on a common EVA materials in support of this effort.
- Presented updated draft to WG2 and received additional comments on draft. UL is including the comments into a revised IEC 61730-1 committee draft (CD) which we expect to present to the IEC WG2 committee by Christmas 2011.
- UL is responding to comments from the proposed adoption of IEC 61215 and IEC 61646 as US ANSI consensus performance standards to the UL 1703 STP.
- Held task group teleconferences to: revise IEC 61730-1 creepage and clearance section to be consistent with IEC 60664, further revise the polymeric requirements, module wiring/interconnectivity requirements and address comments and proposed revisions throughout the document.
- Presented details on the IEC 61730-1 2nd edition draft to the IEC TC82 WG3-6 working group to coordinate with PV systems level standards and installation guidelines. Received critical information which resulted in modifications to the draft.
- Forwarded an updated draft to IEC 61730-1 task group members requesting additional comments on draft. UL is including the comments into a revised IEC 61730-1 committee draft (CD) which we expect to present to the IEC WG2 committee by January 2012.
- UL is responding to comments from the proposed adoption of IEC 61215 and IEC 61646 as US ANSI consensus performance standards to the UL 1703 STP.
- Held task group bi-weekly teleconferences to revise IEC 61730-1. Addressed significant comments on 2nd edition NWIP draft, (completed at the end of 2011) in an effort to make the draft a CD (Step after NWIP) to reduce overall project timing. The 61730-1 2nd edition CD draft is being formatted and placed into the IEC template and will be delivered to IEC Head Office and WG2 in mid April 2012.
- Made 61730-1 presentation in Oslo, Norway, during October of 2012.
- UL hosted a second 61730-1 US team meeting to address the 61730-1 2nd Edition proposal.
- Made presentation of the current draft of IEC 61730-1 to WG2 at the meeting in Jamaica during May 2013.

<u>UL1741 and IEC62109</u>

- Participated in meetings of Working Group 6 and draft language for IEC 62109-1 (general requirements) and IEC 62109-2 (PV inverter specific requirements). 62109-1 was published in 2010 and 62019-2 was published in

<u>Grounding</u>

- Listing requirements for products installed using mounting brackets different than those used during the UL1703 test. – UL has begun working with manufacturers of racks and clips to develop generic safety requirements.
- Listing requirements for grounding lugs. UL is working with a task group of manufacturers and industry experts and has almost completed a proposal for PV module and PV system grounding lugs.

Other Standards Work

- UL held a large, in person UL1703 STP meeting on December 9th and 10th, 2010, at UL Northbrook's facility. 53 people attended the meeting. See meeting report for details.
- Participation in multiple UL1703 STP Materials Deformation Task Group teleconferences with the objective of finalizing a proposed revision to UL1703 to address this issue.
- Participation in the UL1703 STP Standing Task Group to Maintain Consistency with the NEC.
- Participation in the UL1703 STP Retest Guidelines Task Group to develop non-mandatory retest guidelines for inclusion in UL1703.
- Participation in the UL1703 STP Grounding Task Group to finalize the draft proposal developed to modify the Bonding and Grounding, Section 11, requirements.
- Participation in the UL1703 STP Diode Robustness Task Group to review UL1703, as a whole, with regards to diodes and the related issues.
- Attended NREL PV Reliability conference in February. Presented an update on the status of UL1703 including the results of the UL1703 1STP meeting, the status of IEC61703 and UL61703, the status of PV IEC plastics task groups, and, the status on UL Subject 1699B.
- Participation in the UL1703 Performance Requirements Clarification Task Group to review the performance requirements of UL1703 with regards to clarification, technical accuracy and consistency.
- Participation in the UL1703 STP Materials Deformation Task Group with the objective of finalizing a proposed revision to UL1703 to address this issue.
- Completed revisions to UL1703 for Thin-film modules.
- UL published the IEC 61215 and IEC 61646 as US ANSI consensus performance standards to the UL 1703 STP.
- UL has established a STP related to Subject 2703, PV Mounting Systems requirements. Subject 2703 has been submitted for comment. Starting to revise Subject 2703 based on comments being received from the STP. Established a writing team and five sub-task groups to address specific sections of the standard.
- Development of a Standards Technical Panel (STP) for UL Subject 2703.
- UL has established a STP related to Subject 3703, PV Tracker requirements. Subject 3703 has been submitted for comment. Revised Subject 3703 based on comments being received from the STP.
- UL has added Subject 3730 to the responsibilities of the 1703 STP and submitted that standard for comment. Completed publication of Subject 3703, PV Tracker requirements. Began preparation of the documents to be presented to the appropriate STPs for acceptance as ANSI consensus standards.
- UL has established a STP related to Subject 8703, CPV requirements. Subject 8703 has been submitted for comment. Starting to revise Subject 8703 based on comments being received from the STP.

- Developed Outline of Investigation for Photovoltaic Junction Boxes and Distributed Generation Wiring Harnesses. Began preparation of the documents to be presented to the appropriate STPs for acceptance as ANSI consensus standards.

Deliverables:
Stakeholder Meeting December 17, 2007
Stakeholder Meeting July 9, 2008
Stakeholder Meeting March 24, 2009
Annual Solar ABCs Stakeholder Meeting, September 27, 2007, Long Beach, CA
Annual Solar ABCs Stakeholder Meeting, October 17, 2008, San Diego, CA
Annual Solar ABCs Stakeholder Meeting, October 30, 2009, Anaheim, CA
Annual Solar ABCs Stakeholder Meeting, October 15, 2010, Los Angeles, CA
Annual Solar ABCs Stakeholder Meeting, October 21, 2011, Dallas, TX
Annual Solar ABCs Stakeholder Meeting, September 14, 2012, Orlando, FL
Annual Solar ABCs Stakeholder Meeting, July 11, 2013, San Francisco, CA
UL 1699 PV AFCI Meeting April 7-8, 2008
Stakeholder meeting on October 30, 2009 to develop recommendations on NRTL issues
UL PV AFCI Ad Hoc Meeting on November 30 – December 1, 2010
Participation in UL 1703 Working Groups during 2011
Have documentation of UL work on different standards
Fire Rating Research Work
Fire Rating briefings on November 19, 2009 for Steering and Advisory Committees, December 1, 2009 for industry and December 7, 2009 for Cal FIRE
Flammability Stakeholder meeting in January 2010 to develop plans for next phase of research
Stakeholder meeting on Flammability research on January 11, 2011
Solar ABCs Interim Report: Flammability Testing of Standard Roofing Products in the Presence of Stand-off Mounted PV Modules

Task 4.2.2 Photovoltaic System Grounding Issues

Solar ABCs will compile PV system grounding requirements (from the *NEC* and UL Standards) and address PV system and component grounding issues associated with PV modules, PV inverters, PV DC combiners, AC modules and microinverters, DC to DC converters, DC PV arc suppression devices other components. The compilation will discuss grounding conductor sizes, locations, routing and connection points. The document will be widely available to not only equipment manufacturers, but also to systems integrators and installers as well as to members of the *NEC* Code Making Panels and the UL Standard Technical Panels to provide background information to those individuals involved with improving and clarifying those documents. This work is complementary to the work of Task 4.2.1 on Photovoltaic Module Frame Grounding Issues and ongoing changes to the *NEC*, UL 1703 and UL 1741 as well as other standards.

Solar ABCs published the following report:
Photovoltaic System Grounding
Author: John Wiles, New Mexico State University
This report addresses the requirements for electrical grounding of photovoltaic (PV) systems in the United States. Solar ABCs. The report explains what grounding is and defines different types of grounding. It also describes existing National Electrical Code® (NEC®) grounding requirements in some detail, explains the basics System Grounding of grounding

PV equipment and systems, and notes the U.S. organizations responsible for developing and publishing grounding and safety standards. In addition, the report discusses grounding requirements for equipment such as microinverters and AC PV modules, and clarifies the differences between PV system and conventional electrical power systems (utility, generator, or battery sourced) grounding requirements. Finally, it includes an explanation of utility and NEC grounding requirements.

Conducted webinar on November 8, 2012 attended by 175 participants.

Deliverable:
Solar ABCs Report: Photovoltaic System Grounding – October 2012

Task 4.2.3 Flammability Testing of Roofs in the Presence of PV Modules

Solar ABCs investigated the flammability tests for standard roofing products when standoff-mounted PV modules were present. Solar ABCs developed and refined specific tests and procedures that can be applied to PV-roof systems to assess and assign a fire rating to roof assemblies. The results of these tests will be provided to standards making bodies to provide input for modifications to existing codes and standards such as UL1703 and the International Building Code. Stakeholder groups reviewed and evaluated all progress and results. This work began under Task 4.2 and a SOPO amendment created this separate task.

- In 2006, the UL White Book States, "Installation of modules on or integral to a building's roof system may adversely affect the roof covering materials' resistance to external fire exposure if the module has a lesser or no fire resistance rating. Roof covering materials will not be adversely affected when the modules have an equal or greater fire resistance rating than the roof covering material."
- A March 20, 2008 meeting between CalSEIA and UL discussed the following items:
    - Statement in UL White Book is ambiguous and confusing
    - Industry would like information on what types of roof materials should be used to test the effect of modules over roof materials
    - UL is interested in pursuing a PV module-specific fire testing research project with industry to develop specific data to support new or revised fire test requirements for PV modules and their potential effect on the fire resistance of roofing materials. UL will propose to the Solar ABCs that currently funded work be re-prioritized to help fund that research project.
    - UL White Book revised to state, "Installation of modules on or integral to a building's roof system may or may not adversely affect the roof covering materials' resistance to external fire exposure if the module has a lesser or no fire resistance rating."
- On May 28, 2008, the Solar ABCs Steering approved a high priority topic of roof-top PV module-specific fire research, testing and rating systems.
- UL organized meetings on February 13, 2009 and April 13, 2009 to plan the research effort and discuss results. UL personnel, Bill Brooks, and Larry Sherwood attended the meeting.
- UL organized a meeting in April 13, 2009 to plan the research effort and a meeting in June to review Phase One results and plan Phase Two tests. UL personnel, Bill Brooks, and Larry Sherwood attended these meetings.
- During 2009, UL conducted the following tests:
    - Studies of variables affecting system fire classification rating:

    - Air gap between roof and PV
    - Set-back from roof edge
    - Vertical or Horizontal supports
    - Fire classification of PV module (A or C)
    - Fire classification of roofing (A, B, or C)
    - Mitigation Tests (flashing, setback, screens
- Held webinar briefings on November 19, 2009 for Solar ABCs Steering and Advisory Committees, December 1 for Industry, and December 7, 2009 for CalFire
- Held National Stakeholder Meeting in San Jose, California on January 28, 2010. 26 stakeholders attended.
- Presented Flammability Test results
- Received comments from working group members for the Interim Report
- Discuss the applicability of the test methods and the meaning of the results
- Develop specific recommendations for future research
- UL organized a meeting in July 24, August 6, and August 25, 2009 to review test results, plan for future tests, and discuss recommendations. UL personnel, Bill Brooks, and Larry Sherwood attended these meetings.
- On October 1, 2010, held Solar ABCs Flammability Working Group meeting via conference call
- Adopt new Test Protocols in UL 1703
- Conduct Tests for Items 1-3 of March 2010 Test Plan
- Meeting participants included industry, code and fire officials, fire laboratories in addition to those who participated in the research.
- UL presented test results from to the UL1703 STP on December 19, 2010. STP appointed a Working Group chaired by Bill Brooks to develop a new fire classification test.
- UL provided a summary of test results to the ASTM E5 Fire Test Committee
- UL met with representatives of the National Roofing Contractors Association and provided a summary of the results on November 18, 2010.
- In December 2010, UL conducted additional fire tests – low-slope roofs and module at angle relative to roof.
- Began development of systems level test including formulation of generic PV Type categorization scheme and roof type categorization.
- Held Working Group meeting on January 11, 2011 to obtain input for next round of research.
- Robert Backstrom (UL), Dwayne Sloan (UL), and Larry Sherwood (Solar ABCs) gave presentation on research at National Roofing Contractors Association International Roofing Exposition.
- Brooks sent revised versions of the fire rating and grounding proposals to the respective task groups for UL1703 to solicit comments for the final submittal to the UL1703 STP. The fire rating task group met in a conference call on August 10, 2011.
- Participated in the California Governor's Symposia on Alternative Energy (2011) summarizing the Solar ABCs work on PV Fire issues.
- Evaluated ASTM E648 and ASTM E1321 test methods for determination of critical flux for the Part 3 evaluations.
- Presented results of initial research to 26th EU PVSEC Show/Conference in Hamburg, Germany (2011).
- Held a webinar on November 16, 2011 to brief stakeholders on the issues

- Held a stakeholder meeting on December 14, 2011 in Northbrook, IL with members from Solar ABC's fire group, UL 1703 and UL 2703 STP committees. Presented results of initial critical flux experiments and conducted demonstrations of compliant roofing system spread of flame tests and with the addition of PV modules (noncompliant). Developed plans for next phase of research. A draft for the systems level test was presented.
- Met on phone with SEIA representatives regarding SEIA's concerns on Fire Classification issue (meetings via a conference call on February 10 and March 8 and in Washington, DC on March 15, 2012)
- Conducted tests to inform new fire classification rating test
- Participated in UL 1703 Task Group Meetings
- Organized and facilitated fire classification meetings with UL, B. Brooks, SEIA and roofing industry representatives
- Worked with SEIA to help ensure that industry is well-informed and the concerns of the industry are addressed with the proposed fire classification testing protocol for the UL1703 standard
- Met with California Fire Chief Hoover and UL
- Organized Stakeholder Meeting on August 28, 2012 for stakeholders to provide comments on proposed new fire classification test. Meeting attended by 29 stakeholders on-site and 9 on webex.
- Met with J. Smirnow, SEIA and S. Jakowski of UL to develop plan for Industry Solution testing
- Larry Sherwood gave presentation on fire classification issue at Solar Power International Conference in September 2012
- Tests were conducted to provide additional validation for the setback in the new test method developed for UL 1703.
- Proposed new test method submitted for comment to UL 1703 Standard Technical Panel in October 2012 and for a vote in February 2013. Change to UL 1703 approved in July 2013.
- Facilitated two webinar discussions of proposal for UL 1703 Standard Technical Panel members.
- Brooks worked with UL and SunPower representatives to perform important tests on January 28-29, 2013 to help revise the UL1703 fire classification proposal.
- Facilitated two meetings of a stakeholder group to develop Industry Solutions Tests. Testing for the Industry Solutions/Exemptions was conducted May 28 through May 31. The baseline low slope and steep slope tests did not meet the desired parameters. Additional work is currently planned for July 5th.

Deliverables:

UL Research Reports published:

- Effect of Roof-Mounted Photovoltaic Modules on the Flammability of Roofing Assemblies (September 30, 2009, revised March 5, 2010)
- Effect of Rack Mounted Photovoltaic Modules on the Flammability of Roofing Assemblies – Demonstration of Mitigation Concepts (September 30, 2009, Revised February 10, 2010)
- Effect of Rack Mounted Photovoltaic Modules on the Fire Classification Rating of Roofing Assemblies (January 30, 2012)

- Characterization of Photovoltaic Materials – Critical Flux for Ignition/Propagation (January 16, 2012)
- Determination of Effectiveness of Minimum Gap and Flashing for Rack Mounted Photovoltaic Modules (March 29, 2012)
- Considerations of Module Position on Roof Deck During Spread of Flame Tests (July 24, 2012)
- Validation of 42" PV Module Setback on Low Slope Roof Experiments (November 7, 2012)
- Validation of Roof Configuration (February 12, 2013)

Solar ABCs Reports published:

Interim Report: Flammability Testing of Standard Roofing Products in the Presence of Stand-Off Mounted PV Modules
Authors: Andrew Rosenthal, NMSU; Larry Sherwood, Solar ABCs; Bill Brooks, Brooks Engineering; Pravinray Ghandi, UL; Bob Backstrom , UL

Fire Classification Rating Testing of Stand-Off Mounted Photovoltaic Modules and Systems
Authors: Larry Sherwood, Solar ABCs; Bob Backstrom, Dwayne Sloan, Christopher Flueckiger, UL; Bill Brooks, Brooks Engineering; Andrew Rosenthal, NMSU

Task 4.2.4 Subtask 1- Photovoltaic Module Frame Grounding Issues

Solar ABCs will develop and simple, documented and practical proscriptive "recipe" procedures for equipment grounding of PV components will be developed and made publically available. Test methods will be developed for the purpose of evaluating the long-term reliability of the ground connections between metal parts in a PV array applicable to any roof-or ground mounted PV array mounted on metal structures. The resulting methods will be applicable to any roof-or ground mounted PV array mounted on metal structures.

Solar ABCs published the following three reports:

Module Frame Grounding Lay of the Land
Authors: Greg Ball, BEW Engineering

This report focused on the existing state of affairs associated with module/system grounding, problems experienced in the field, issues with existing standards, and proposals floated to date to improve the existing standards.

Grounding Photovoltaic Modules: Issues and Recommendations
Authors: Greg Ball, BEW Engineering; Timothy Zgonena and Christopher Flueckiger, UL

The final report includes results from substantive testing performed by UL on accelerated aging of grounding components via corrosion mechanisms. The report also documents recommendations for changes to current testing requirements for grounding equipment, based on conclusions developed by the UL 1703 STP subcommittee focusing on module frame grounding.

Grounding Photovoltaic Modules: Addendum Report on Corrosion Testing
Authors: Greg Ball, BEW Engineering; Timothy Zgonena and Christopher Flueckiger, UL

The Addendum recommends adopting PV module corrosion test protocols recently published by the IEC TC82, which better address module-specific issues than the more general ASTM and IEC standards.

Other activities under this task:
- Greg Ball supported a proposal to the UL1703 Standard Technical Panel (STP) for revisions to the module grounding language.
- Held webinar on July 17, 2012 to brief stakeholders on report and answer questions. Webinar attended by 129 stakeholders.

Deliverables:
Solar ABCs Report: Module Frame Grounding: The Lay of the Land
Solar ABCs Report: Grounding PV Modules: Issues and Recommendations
Solar ABCs Report: Grounding PV Modules: Addendum Report on Corrosion Testing

Task 4.2.4: Ground-Fault Protection Improvements to Prevent Fires

Photovoltaic systems have caused fires on at least two large buildings. The fires have been traced to a detection blindspot that causes the ground fault system to be ineffective. To address this problem, Solar ABCs will publish a white paper that provides background information on the problem and its causes and recommends mitigation methods. Then, Solar ABCs will 1)conduct research to determine the conditions where existing ground-fault protection is inadequate and 2) develop a mitigation proposal for systems with inadequate protection which can be implemented through changes to the NEC and UL standards. This research will include both engineering analysis and field evaluations of existing installations. Solar ABCs will consult with stakeholders throughout the project and publish a final report with mitigation recommendations.

- Held Stakeholder Meeting on October 28, 2011 in Northbrook, IL to examine the issue and develop plans for future research.
- Held Stakeholder Webinar Meeting on February 2, 2012 to brief stakeholders on current activities.
- Ground-Fault Team met frequently to discuss results, revise research plan, and develop recommendations.
- Hosted webinar on May 2 allowed stakeholders to review and provide comments on the final draft of the report. 44 stakeholders attended this webinar.
- The second on June 25 provided a briefing on the final report and was attended by 77 stakeholders.

<u>Research</u>
- Contacted inverter representatives to determine their present techniques for detecting ground-faults on grounded and ungrounded arrays, as well as their future plans for GFDI circuits.
- Dave Click, Andy Rosenthal, Bill Brooks meeting with Duke Power and Southern Energy Management on December 8, 2011. The meeting consisted of a discussion of the issues as well as an examination of a rooftop 500kW system where the inverter blindspot was successfully demonstrated.
- NMSU led two field investigations to characterize ground-fault blindspot. PV systems in Union City, CA and Fresno, CA were tested in close coordination with SunPower (Mark Albers). The investigations verified blindspot existence and measured introduced fault

currents in two different inverter types. Two key results of this round of testing were introduction of a fault with current greater than string current (inverter operating) and direct measurement of the impedance of the equipment grounding conductor of an operational PV plant.

- Brooks and BEW (Greg Ball) continued to work with the Solar ABCs task group on the research project investigating the ground-fault protection blindspot that exists with many large PV inverters. Brooks helped perform the research through this quarter and worked with the New Mexico State University team on May 3-4, 2012 in Fontana, California at the Southern California Edison arrays that were tested.
- Brooks and BEW (Greg Ball) continued to work with the Solar ABCs task group on the research project investigating the ground-fault protection blindspot that exists with many large PV inverters. Brooks helped perform the research through this quarter with notable field tests occurring on August 6 in Hayward and on August 7 in Davis, California.
- Greg Ball also worked with Mark Albers of SunPower to re-test simulated ground faults on a large roof top system with AE inverters in Northern California. The tests indicated that the inverters were able to detect some grounded conductor string faults.
- FSEC replaced the GFDI fuses of two inverters at FSEC and two residential inverters on FSEC employee-owned PV systems, downsizing them from 1.0 to 0.1A to test the performance of the GFDI circuits in a hot-humid environment. There have been no issues to report.

Solar ABCS published the following reports:

Solar ABCs White Paper: ***The Ground-Fault Protection Blind Spot: Safety Concern for Larger PV Systems in the U.S.***
Author: Bill Brooks, Brooks Engineering
This white paper addresses an important safety issue in the design of many U.S. photovoltaic (PV) systems—undetected faults in grounded PV array conductors. This issue came to light during investigations into two well-publicized PV system fires. The first occurred on April 5, 2008, in Bakersfield, California, and the second occurred on April 16, 2011, in Mount Holly, North Carolina.
This paper provides a basic explanation of the cause of these fires, followed by an outline of a limited research plan designed to develop solutions.

Analysis of Fuses for "Blind Spot" Ground Fault Detection in Photovoltaic Power Systems
Authors: Jack Flicker and Jay Johnson, Sandia National Laboratories
This report contains portions of a recent Sandia National Laboratories (Sandia) technical report that investigated ground fault detection deficiencies associated with faults occurring on the grounded current-carrying conductor (CCC) of a photovoltaic (PV) power system. This report characterizes ground fault protection limitations in current PV system designs. Sandia developed a functional circuit model of the PV system including modules, wiring, switchgear, grounded or ungrounded components, and inverters. This model was used to analyze the effectiveness of PV system fault detection methods for a range of ground fault fuse sizes to determine the optimal fuse size for improving ground fault detection sensitivity.

Inverter Ground-Fault Detection "Blind Spot" and Mitigation Methods
Authors: Greg Ball, DNV KEMA; Bill Brooks, Brooks Engineering; Jack Flicker and Jay Johnson, Sandia National Laboratories; Andrew Rosenthal and John Wiles, New Mexico

State University; Larry Sherwood, Sherwood Associates; Mark Albers, SunPower Corporation; Tim Zgonena, Underwriters Laboratories, Inc.
This is the final report Solar ABCs "blind spot" series. It concludes a research program into an important safety issue associated with the design of many U.S. photovoltaic (PV) systems. It includes results of field research conducted to characterize basic array wiring impedance properties and their effects on ground fault detection, circuit modeling, and analyses of high and low impedance faults that may occur throughout the array. It also includes a technical review of the effects of ground fault detection blind spots on different array topologies (grounded, ungrounded, and grounded through the alternating current connection).

Deliverables:
Solar ABCs White Paper: Ground-Fault Protection Blind Spot: Safety Concern for Larger PV Systems in the U.S.
Solar ABCs Report: Analysis of Fuses for Blind Spot Ground Fault Detection in Photovoltaic Power Systems
Solar ABCs Report: Ground-Fault Detection Blind Spot and Mitigation Methods

Task 4.2.5: PV Maintenance and Inspection Guidebook

Some solar installations are aging and some of the installers of these older systems are no longer in business. These systems need to be properly maintained to ensure safe and reliable operation. Solar ABCs will publish a Maintenance and Inspection Guidebook, which includes best practices for inspecting and maintaining systems. Recommended inspection procedures will include both visual inspections as well as electrical and mechanical tests.

Solar ABCS published the following report.

PV System Operations and Maintenance Fundamentals
Authors: Adam Burstein and Josh Haney, Next Phase Solar
This preliminary O&M guide is intended to help qualified individuals safely maintain and inspect PV systems. It identifies currently recognized major safety requirements during PV servicing and repair and provides details for a number of O&M tasks. Within the broader PV community, there are currently three working groups focused on this issue. It is expected that they will publish a comprehensive O&M guide in the next few years. In the meantime, this report serves as an introduction to O&M for PV installations. This introductory report includes practical guidelines for PV system maintenance and options for inspection practices for grounded PV systems.
This report does not cover bi-polar, ungrounded, stand-alone, or battery backup systems.

Deliverable:
Solar ABCs Maintenance and Inspection Guidebook

Task 4.3: *The National Standards Coordination Working Panel*

Objective: The *National Standards Coordination Working Panel* will develop a prioritized list of projects, solicit contributions and coordinate activities between the ASTM E44.09, IEEE SCC21 and IEC US TAG to pursue common developments for PV module and system standards. The panel shall give priority to considering the need for a national PV module (or system) performance rating system, as well as the best means to implement such a rating system. See also Task 4.5, which contains related activities.

PowerMark team members PowerMark, BEW Engineering, Sunset Technologies facilitated a stakeholder conference call on January 16, 2008 to discuss the purpose of this panel and to overview the standards organizations.

A National and International Standards Coordination Panel meeting was held June 2-4, 2008 at the NREL Visitors Center in Golden CO. Each of the three days was dedicated to one of three key standards development groups: ASTM, IEC, and IEEE.

Solar ABCs published a White Paper:
Impacts on Photovoltaic Installations of Changes to the 2012 Editions of the International Building Code and International Residential Code.

Mike Sheehan, IREC, contributed in the development of the next draft of IEEE 1547.8 Section 4.2.1 4.2.2. The significance of this draft is it has provisions on allowing higher penetrations of DG beyond the current 15% line section limit.

BEW also attended the IEEE 1547.8 meeting held February 9-10, 2012. The standard is in the early writing phase and its content and purpose may change with a movement to adjust the underlying IEEE 1547 standard.

Deliverables:
Stakeholder Meeting January 16, 2008
Stakeholder Meeting June 2-4, 2008
SEMI convened meeting May 13, 2009 to write standard based on Solar ABCs report
Participated in ASTM Accelerated Testing Meetings July 23, 2009 and August 4, 2009
Participated in ASTM Grounding Meeting on July 28, 2009
Attended ASTM E44.09 meeting on BIPV
Annual Solar ABCs Stakeholder Meeting, September 27, 2007, Long Beach, CA
Annual Solar ABCs Stakeholder Meeting, October 17, 2008, San Diego, CA
Annual Solar ABCs Stakeholder Meeting, October 30, 2009, Anaheim, CA
Annual Solar ABCs Stakeholder Meeting, October 15, 2010, Los Angeles, CA
Annual Solar ABCs Stakeholder Meeting, October 21, 2011, Dallas, TX
Annual Solar ABCs Stakeholder Meeting, September 14, 2012, Orlando, FL
Annual Solar ABCs Stakeholder Meeting, July 11, 2013, San Francisco, CA

Task 4.3.4: - Photovoltaic Module Power Ratings

Effective module power rating standards to address current market and deployment concerns is a high priority topic. Solar ABCs developed a recommendation on PV module power rating tolerances. With input from stakeholders, Solar ABCs developed a more detailed power rating tolerances policy including a recommendation on the venue for its certification.
Deliverables:

- PowerMark conducted a Stakeholder webinar on the Subject of "Module Power Rating Tolerance suggested Policy" on February 26, 2010. Sixty-nine people participated. ASU, FSEC and PowerMark developed the presentation document used during the Webinar. The same team is now working on the Interim report.
- Held stakeholder webinar on March 3, 2011 to receive input on proposed policy. 84 people attended.

- Solar ABCs developed a proposed standard (titled: *Nameplate, Datasheet and Sampling Requirements of Photovoltaic Modules*) based on the recommended policy document. A public webinar based on the proposed standard was conducted on November 3, 2011. The comments obtained from the webinar participants and review committee members were incorporated in the proposed standard
- The Steering Committee designated Underwriters Laboratories as the standard developing organization (SDO) to convert it into a National Standard.

Solar ABCs published the following reports for this task:

Solar ABCs Policy Recommendation: Module Power Rating Requirements **(March 2011).**
Authors: Govindasamy TamizhMani, Arizona State University and Alex Mikonowicz, PowerMark Corporation
This policy recommends reducing PV modules power rating tolerances so that performance of installed PV systems will meet consumers' expectations.

A Proposed Standard for Nameplate, Datasheet and Sampling Requirements of Photovoltaic Modules **(January 2012)**
Authors: Govindasamy TamizhMani, Joseph Kuitche, Arizona State University; Alex Mikonowicz, PowerMark Corporation
This draft standard implements the previous policy recommendation.

Photovoltaic Module Rower Rating per IEC 61853-1 Standard: A Study Under Natural Sunlight **(March 2011)**
Authors: Govindasamy TamizhMani, Karen Paghasian, Joseph Kuitche, Meena Gupta Vemula, Ganesh Sivasubramanian, Arizona State University

Validation of Draft International Electroctechnical Commission 61853-2 Standard: Angle of Incidence Effect on Photovoltaic Modules **(March 2013)**
Authors: Brett Knisely, Suryanarayana Vasantha Janakeeraman, Joseph Kuitche, Govindasamy TamizhMani, Arizona State University
This study tested and validated the draft IEC 61853-2 standard's experimental procedures and related mathematical models for the measurement of angle of incidence effects on photovoltaic modules.

Deliverables:
Solar ABCs Policy Recommendation: PV Module Power Rating Requirements
Photovoltaic Module Rower Rating per IEC 61853-1 Standard: A Study Under Natural Sunlight
Stakeholder Meeting February 26, 2010
Stakeholder Meeting March 3, 2011
Stakeholder Meeting November 3, 2011
Solar ABCs Report: A Proposed Standard for Nameplate, Datasheet, and Sampling Requirements of Photovoltaic Modules
Solar ABCs Report: Validation of Draft International Electrotechnical Commission 61853-2 Standard: Angle of Incidence Effect on Photovoltaic Modules

Task 4.3.5: Subtask 2 - Photovoltaic System Energy Rating

With the adoption of IEC 61853, good module performance data is now being collected as manufacturers comply with this standard. However, there is no current requirement to make this data publicly available and therefore it is not available as inputs to performance models. This work will propose additional changes to IEC 61853 addressing reporting requirements that enhance the usability of the test data for use as input data by the model simulators to be able to increase the accuracy of the long-term performance predictions.

- PowerMark and North Carolina Solar Center organized a webinar in October 2011 to discuss the preliminary draft of the PV System Energy Performance Evaluation.
- FSEC and PowerMark held discussions with NREL on different options of using the new PV System Energy Evaluation procedure to develop an independent simulation model or in combination with existing models such as PV Watts and SAM (Solar Advisor Model).
- In response to stakeholder feedback, prepared revised plan for this task. Held meeting on August 15, 2012 with representatives of DOE, NREL and Sandia to coordinate efforts on this task. The new task will allow integration of the activity of "Name Plate Rating and Specification Sheet requirements to be made available for the integration in the development of models used in performance prediction.
- Collection of stakeholder input. This input was gathered primarily with stakeholder-group-specific online surveys. Approximately 15 to 25 of the most significant stakeholders in each of the three targeted groups (PV model developers, PV test labs, and PV module manufacturers) were sent requests for input on the Solar ABCs project considering action that may lead to testing and reporting requirements for module performance rating to IEC 61853-1 standard.
- Organized face-to-face stakeholder meeting in conjunction with PV America West conference in San Jose, CA on March 18, 2012.
- Propose additional changes to IEC 61853 addressing reporting requirements that enhance the usability of the test data for use as input data by the model simulators to be able to increase the accuracy of the long-term performance predictions.The proposed changes to IEC 61853 were submitted to the Convenor to IEC 61853 for inclusion in the maintenance cycle.

Deliverables complete:
Stakeholder Meeting in October 2010
Proposed changes to IEC 61853

Task 4.3.7: Accelerated Lifetime Testing

Solar ABCs will conduct a comprehensive literature review and evaluation to develop transfer functions for a draft test protocol PV module accelerated life test protocol. Specific data needs will be identified for test procedures as well as the methods by which the validity of these procedures will be demonstrated.

Solar ABCs published two reports:

A Literature Review and Analysis on Accelerated Lifetime Testing of PV Modules
Authors: GovindaSamy TamizhMani and Joseph Kuitche, Arizona State University
This report provides a literature review and associated analysis of photovoltaic (PV) field failures, degradation mechanisms and statistics, and available accelerated testing (AT) methodologies. To generate this report, the authors collected and

systematically analyzed the major sources of literature on PV module reliability and durability. The report covers:

- the difference between reliability and durability;
- common failure and degradation modes and mechanisms of PV modules;
- accelerated stress types (including potential induced degradation), levels, and prioritization;
- pitfalls in preparing representative sample designs for accelerated stress testing;
- existing and planned (potential) accelerated comparative and lifetime testing programs;
- key attributes of accelerated comparative and lifetime testing programs;
- considerations for designing and developing new accelerated comparative and lifetime testing programs;
- discussion of a possible approach for a PV rating system; and
- physical and statistical models for lifetime prediction using black-box and white-box approaches based on field degradation data and accelerated test data.

Validating PV Module Durability Tests

Author: Allen Kielnik, Atlas Material Testing Technology

This report details a comprehensive long-term multi-step effort required to develop and validate both current and new durability tests and introduces a roadmap to the development of a service life prediction methodology. It explains basic concepts and principles of durability and reliability testing, service life prediction methodology, and test validation. It summarizes the development rationale leading to the current International Electrotechnical Commission (IEC) module qualification standards and discusses their strengths and weaknesses. Further, it summarizes the main known or suspected failure modes of photovoltaic (PV) modules, currently proposed alternative test protocols, and highlights of ongoing industry and standards activities. The report also includes a gap analysis on these items, a process framework for validating tests, and a summary of efforts underway to establish PV materials tests. Finally, the report recommends an interim solution using the current standards process.

The following outreach was conducted regarding this work:

- Participated in the conference calls organized by ASTM and Solar Power Partners (an industry consortium) to develop accelerated lifetime testing protocols.
- ASU presented some portions of the Accelerated Lifetime Testing report in the "PV Module Quality Forum" organized by NREL, JRC and AIST in San Francisco in July 2011.
- ASU made presentation titled "**Standards of PV Modules: *Differences and Test Results***" at the APEC (Asia-Pacific Economies Cooperation) Conference held in San Francisco on September 15, 2011.

Deliverables:

Solar ABCs Report: A Literature Review and Analysis on Accelerated Lifetime Testing of PV Modules

Solar ABCs Report: Validating PV Module Durability Tests

Task 4.4: *The Interconnection/Net Metering Working Panel*

Objective: The *Interconnection/Net Metering Working Panel* will focus on providing necessary support to U.S. PV stakeholders in this important and often diverse context.
Task Description: Tasks for this working panel fall within two subtasks, web-based activities, coordination activities, training and outreach activities. The panel shall coordinate with ongoing IREC activities in this area to minimize duplication of effort and maximize leveraging opportunities.
Subtask 4.4.1 Web-based Activities. Web-based activities will include developing and operating a list-serve forum to facilitate discussions of interconnection and net metering issues arising from the Solar ABCs members and general public. Web based activities for this panel will continue throughout the entire project period.
Subtask 4.4.2 Coordination Activities. The working panel will hold regular, open meetings for Solar ABCs to establish priorities and action plans for addressing the most pressing problems facing Solar ABCs members. The working panel will provide information to the study panel of the same name for its preparation of the year 1 study report of these issues.
Timeline and Expected Outcomes: The working panel deliverables include participation by panel leader and membership in the Panel list-serve and public forum. All meeting minutes will also be provided to the *Project Administrator* for inclusion in regular progress reports. These activities will continue throughout the entire project period.
Impact: The intended impact of *Interconnection/Net Metering Working Panel* is increased access by Solar ABCs to discussions and solutions of interconnection and net metering challenges including facilitating communications between jurisdictions facing such challenges and those who have successfully met them.

On March 26, 2009, the IREC Team held the quarterly stakeholder meeting. About 30 people attended with strong participation from Southern California Edison representatives. The purpose of the meeting was to describe the six potential new areas of study.

Deliverables:
Stakeholder Meeting December 14, 2007
Stakeholder Meeting March 24, 2008
Stakeholder Meeting June 20, 2008
Stakeholder Meeting March 26, 2009
Stakeholder meetings on February 19, 2010 and March 7, 2010
Annual Solar ABCs Stakeholder Meeting, September 27, 2007, Long Beach, CA
Annual Solar ABCs Stakeholder Meeting, October 17, 2008, San Diego, CA
Annual Solar ABCs Stakeholder Meeting, October 30, 2009, Anaheim, CA
Annual Solar ABCs Stakeholder Meeting, October 15, 2010, Los Angeles, CA
Annual Solar ABCs Stakeholder Meeting, October 21, 2011, Dallas, TX
Annual Solar ABCs Stakeholder Meeting, September 14, 2012
Annual Solar ABCs Stakeholder Meeting, July 11, 2013, San Francisco, CA

Task 4.4.3: TOV Overvoltage on Distribution System

From a utility perspective the interconnection of Distributed Generation (DG) to the utility distribution system adds a complication to the design as well as to the normal operation of utility systems. The objective of this project is to characterize the allowable transformer configurations and inverter grounding configurations for the interconnection to the area EPS. The winding configuration of any three phase transformer(s) between the DG and the area EPS will have an

impact on the distribution system, both under steady state and fault conditions, therefore we intend to analyze the different options and standardize the DG Interconnection Transformer configuration to a more functional alternatives. Solar ABCs will publish a report identifying the "best practice" approach to resolve inverter grounding and transformer connection configuration issues. This report will include a list of preferred transformer winding connections and recommendations for inverter grounding that utilities and developers may consider the next time they interconnect with large PV system.

Solar ABCs developed a draft report identifying the "best practice" approach to resolve inverter grounding and transformer connection configuration issues. This draft included a list of preferred transformer winding connections and recommendations for inverter grounding that utilities and developers may consider the next time they interconnect with large PV system.
Author: Michael Sheehan, Interstate Renewable Energy Council

New research on this topic questions the conclusions of the Solar ABCs report. Because there was not time to resolve the inconsistencies, Solar ABCs decided not to publish the report.

Deliverable complete:
Draft Solar ABCs Report with explanation of why this is not published.

Task 4.5: *The International Coordination Working Panel*

Objective: The *International Coordination Working Panel* will be the main U.S. link to the active international standards developing activities of the IEC TC82. This includes coordination of the three key positions: TC Secretary, the US TAG Administrator and US TAG Technical Advisor.

Solar ABCs provided the Secretary of Technical Committee 82 (TC82) of the International Electrotechnical Commission (IEC) through Howard Barikmo of Sunset Technology, Inc. During the contract period, the Secretary guided many standards through the IEC standards development process. A list of these standards is included in the submitted quarterly reports.

The Secretary facilitated the following plenary meetings:

- May 19-23, 2008 in San Francisco, California. A total of nineteen countries were represented. New attendees included delegates from South Africa, Singapore, and India.
- September 28-October 2, 2009, Aix-les-Bains, France. Approximately eighty delegates and guests from nineteen countries were in attendance.
- May 12-13, 2011, Shanghai, China
- October 4-5, 2012, Oslo, Norway

Working Group meetings were held in conjunction with each of these plenary sessions.

In addition, regular Working Group meetings were held throughout the grant period.

Working Group 1

- May 9-11, 2011, Shanghai, China
- December 5-9, 2011, Zermatt, Switzerland
- October 1-3, 2012, Oslo, Norway

Working Group 2

- October 8-12, 2007, Titisee, Germany
- 2009, Loughborough, England
- May 9-11, 2011, Shanghai, China
- September 26-30, 2011, Montreal, Canada
- May 7-11, 2012, Stressa, Italy
- October 1-3, 2012, Oslo, Norway

Working Group 3 (Systems)

- November 1-2, 2007, Burgdorf, Switzerland
- October 20-23, 2008, Busan, Korea
- 2009, Munich, Germany
- November 8-9, 2010, Newcastle, England
- May 9-11, 2011, Shanghai, China
- December 5-9, 2011, Zermatt, Switzerland
- May 13-19, 2012, Vancouver, Canada
- October 1-3, 2012, Oslo, Norway

Chuck Whitaker and then Greg Ball from BEW Engineering chaired Working Group 6 (Balance of Systems)

- October 29-30, 2007, Burgdorf, Switzerland
- October 20-23, 2008, Busan, Korea
- 2009, Munich, Germany
- September 29, 2009
- May 3-4. 2010 Vicente Salas, Spain
- November 10-12, 2010, Newcastle, England
- May 9-11, 2011, Shanghai, China
- December 5-9, 2011, Zermatt, Switzerland
- May 13-19, 2012, Vancouver, Canada
- October 1-3, 2012, Oslo, Norway

Working Group 7

- October 13, 2007, Marburg, Germany
- April 6-8, 2010, Las Vegas, NV
- April 18-20, 2012, Toledo, Spain
- September 5-7, 2012, Golden, CO

<u>Solar ABCs supported the TC82 U.S. Technical Advisory Group (USTAG).</u>

- PowerMark served as the Technical Advisor to the IEC Technical Committee 82 (TC82) U.S. Technical Advisory Group (USTAG). The U.S. TAG is the forum for U.S. stakeholders to provide input on new and revised IEC standards.
- The U.S. TAG held meeting on September 24-25, 2008 in Scottsdale, Arizona. This meeting provides the opportunity for U.S. stakeholders in have input into IEC Standards and was the first USTAG meeting held in almost ten years.
- The TA prepared the US delegation for the TC 82 Working Group meetings throughout the drant period.

- The US TAG grew to as many as 98 members, the largest representation ever achieved and the largest Technical Committee administered by ANSI.
- The US TAG voted on many standards during the grant period. The standards and votes are detailed in the quarterly reports.
- Conducted US TAG meeting in Golden on February 18, 2011. 45 members attended. The US TAG used this meeting to consider, nominate and approve the assignments of 5 additional expert members to WG 7 and 1 expert to WG 3 & 6 to represent the US in those working groups.
- Held US TAG meeting on March 2, 2012 at NREL.
- The US TAG TA sadly reported that our "talented Secretary" Mr. Howard Barikmo expressed a wish to resign and with the involvement of the three Convenors, conducted a "search" for qualified candidates and a formal US TAG vote from two highly qualified candidates. The result was Mr. George Kelly formally of BP Solar was elected and is in the process of installation as Secretary of TC 82.

The Secretary and other Solar ABCs members participated in the following meetings related to IEC Standards:

- Arcing in PV Arrays Workshop in Burgdorf, Switzerland on October 31, 2007.
- International Photovoltaic Reliability Workshop (IPRW) II "Removing Barriers to Photovoltaic Technology Adoption: Reliability, Codes/Standards, and Market Acceptance." This workshop was held in Tempe, Arizona on July 29-30, 2009.
- ANSI sponsored 4th USNC TAG Leadership Workshop on September 3, 2009 in Arlington, Virginia.
- ASTM E44.09 PV meeting in Atlanta, Georgia. Primary reason was to learn what was being planned for addressing Building Integrated PV systems. However, the scope of the ANSI standard has changed to be simply "building attached" PV systems—with the implication this will deal with roof mounted systems. It was also learned that ANSI will form a task group relating to PV glass, with the first meeting taking place in Washington DC on January 20.
- Observed the training class, on December 3, presented to Phoenix area fire fighters. This class was specifically designed to guide fire fighters on the proper attack of buildings on fire that also have PV systems attached. Training was given by Captain Matt Paiss, a member of the San Jose Fire Department.
- Attended 2010 Underwriters Laboratories meeting in Northbrook, Illinois to discuss the progress being made on the dc AFCI circuitry that is required in the 2011 National Electrical Code to mitigate series arcing. This circuitry is, of course, of interest to TC 82 since dc arcing is a possible and serious problem in "legacy" systems that have been in the field for a number of years. It is the intent of the secretary to share this information with WG 6 members; two members from WG 6 were also in attendance at this meeting.
- Attended 2010 meeting at the Underwriters Laboratories in Northbrook, Illinois of the UL 1703 STP (Standard Technical Panel) that not only included new items brought up to add to 1703 but also the harmonization of 1703 with the IEC 61730-1 and -2. Items discussed will be rewritten and submitted through the standard method of the UL STP voting system. This will most likely occur sometime in January 2011.
- Greg Ball presented on at Sandia's inverter reliability workshop in January 2011, focusing on inverter reliability standards and specifically the work going on related to

IEC 62093. This was helpful in gathering additional people to support the revision content.

- Attended and presented at three meetings in February 2011: PHOTON International 1st Safety Conference in San Francisco, NREL's Photovoltaic Reliability Workshop, and the US TC82 Technical Advisory Group.
- On 26 and 27 April, 2011 the secretary attended UL's STP 1741 meeting in Northbridge, Illinois. Contributions were made to these discussions, but the primary item was the formal assignment by the Sunset Technology, Inc. to UL the task of harmonizing five IEC standards under the purview of TC 82. These standards include IEC 61215, IEC 61646 and IEC 62108, all of which are expected to be completed and assigned as American National Standards within a twelve month period by UL from acceptance of the task, since it is expected there will be no changes made to the IEC standard. These standards relate to PV module and CPV module qualification and type acceptance. Two additional standards were also assigned: IEC 62109-1 and -2. Since these are expected generate questions from the STP participating members, UL accepted the assignment and will complete the harmonization process within 30 months of the assignment.
- The secretary attended a two-day workshop by invitation from the IEC Strategic Management Board's SG3 devoted to the Smart Grid. This workshop was held in Frankfurt, Germany June 28 and 29, 2011 and was intended to provide information to technical committees that write standards that have applicability when working with the smart grid and how these will be handled in order to make maximum use of such standards for users.
- The secretary attended the ANSI TAG officer's one-day workshop in Arlington, Virginia on September 13. This was a training session for Technical Committee Technical Advisory Groups.
- Greg Ball attended the NEC 690 code-making panel meeting held in Las Cruces in September, where proposals for the 2014 code were discussed. Several proposals related to ungrounded and 1000V dc systems are of interest because of parallels in IEC standards.
- Brooks participated in the IEC TC64 MT9 meetings refining their PV installation portion of their electrical installation document in Washington, DC on July 5-7. These discussions dealt with many issues directly related to WG3's project IEC 62548, Installation and Safety Requirements for Photovoltaic (PV) Generators. Since Brooks is a member of the NEC CMP4 dealing with the corresponding U.S. document, he was asked to fill in on this committee for co-convener of WG3, Martin Cotterell.
- The secretary attended several Standard Technical Panels hosted by Underwriters Laboratory in Northbrook, Illinois. The first dealt with UL standard 1703 on 25 – 26 October, 2011 then STP 62109, that is in process of harmonizing IEC 62109-1 and -2, on 27 October.
- Greg Ball attended the 2011 UL 1703, UL International Harmonization Committee (62109) and Solar ABCs ground fault task group meetings held at UL in Northbrook, IL.
- The secretary attended the 2012 Annual PV Reliability Module Reliability Workshop Poster presentations of the new standard activities within TC 82 were offered, to include those new items specifically related to thin-film technology. The TAG meeting was received well by all participants, with many questions especially related to the TAG officers proposal to assign experts to the various Working Groups.
- The secretary attended a meeting of SC17B that is charged with writing standards related to Low-voltage switchgear and controlgear, held in Palermo, Italy on January 11,

2012. This was a meeting to begin a liaison relationship with this Sub Committee that related to TC 82's New Work Item Proposal for junction and combiner boxes.

- The secretary was invited to participate in the 34th IEEE PVSC held in Austin, Texas from 5 – 7 June, 2012, in order to act as moderator of Area 9: Modules and Systems: Module Materials, Durability and Performance II (Orals) that was held on 7 June.
- In addition, the secretary was invited to participate and contribute to the US Photovoltaic Manufacturing Consortium (PVMC) workshop, held on June 6 at the same location.
- The secretary was invited to participate in the Intersolar Conference held at the Moscone Center in San Francisco in July where a meeting of the PV Manufacturing Consortium (PVMC) was held, as well as a PV reliability workshop. Discussions on how TC 82 can contribute to the Codes and Standards work to be undertaken by PVMC as part of its contract with DOE ensued, but with no decision reached, other than to continue discussions in the future. The reliability workshop included history of how environmental stress tests were specified by JPL during its various Block procurements starting in the 1970s. One major problem in being able to determine reliability of PV modules is the dearth of failure data. Manufacturers are unwilling to share such data with independent laboratories that can guarantee confidentiality. As a result, the industry as a whole has no failure data base from which reliability numbers can be based. This was highlighted by Dr. Ross, the primary investigator at JPL during the Block PV module procurement.
- Met with Sandy Butterworth, Chairman of TC 88, Wind Turbines. Primary reason for this briefing was to learn how TC 88 is addressing quality management and conformity assessment for its products. Its method of addressing this area is through the IEC Conformity Assessment Board and a newly created Wind Turbine Conformity Assessment Committee. There were several others attending the meeting from WG2 as well as the Assistant Secretary, Mr. Liang Ji. Since the photovoltaic community is facing similar quality and conformance issues, this meeting was quite welcome. It gave us the opportunity of learning the TC 88 route and whether TC 82 should use it as a model. If nothing else, it gives TC 82 information that can be used when getting further information from other QA schemes within the IEC.
- The secretary had been invited to present a paper at the Plastics in PV conference that was held in Phoenix on 19 September, 2012. This was well received by the attendees, most of whom were not familiar with photovoltaics. The primary message to be left was the number of new standards being worked on in TC 82 Working Group 2 that reference plastics and their characteristics and that will be published to assist the PV design engineer in determining physical and chemical attributes of these materials as used in modules.
- Of primary importance in 2012 was the discussion between TC 64 Electrical installations and protection against electric shock and TC 82. For the last several years there had been a dispute between the two committees defining where the boundary is between the committees as it relates to dc safety. Since the primary effort of TC 64 had been electrical installations of ac systems, their standards were lacking in addressing adequately and quickly enough the differences in installation of dc systems. After many discussions we solved the problem by forming a Joint Working Group that is composed of four experts from each TC. It is hoped this JWG will adequately—and quickly—get information to installers and others who build PV systems.

<u>QA Forum</u>

- The secretary participated in the QA Forum in San Francisco, California, July 15 and 16, organized by NREL, the Distributed Generation JRC of the European Commission, and AIST of Japan. Intent of the forum was to introduce more all-encompassing quality assurance provisions that will provide photovoltaic product with more easily determined and understood energy output in various areas of deployment, as well as a means of providing accelerating test factors that will more likely let users know a realistic lifetime of the product. Much work, obviously, needs to be done.
- PowerMark (Alex Mikonowicz) developed and presented the keynote on the second day of the International QA PV Forum in San Francisco in the middle of July. The material presented stressed the importance of control of the incoming materials and Mfg. processes and where to focus to achieve consistency and uniformity. PowerMark (Alex) will act as the US lead for the evolution of the "Americas" work on the QA Forum.
- Solar ABCs through PowerMark was the US lead for the evolution of the "Americas" work on the QA Forum Task group 1 conducted an overview of the total task group 1 progress at the NREL Reliability. QA forum Task groups 2-5 proposed changes in the qualification standards as well as addition qualification suggestions. An Americas web page for QA task group 1 was established. Established a weekly conference call with approximately 14 active participants and has completed the total review of ISO 9000-2008 and conducted a thorough review of all PV related additions as well.

Deliverables:
TC 82 Secretariat (quarterly reports)
TC 82 Working Groups (quarterly reports)
U.S. TAG Meeting on September 24-25, 2008
Annual Solar ABCs Stakeholder Meeting, September 27, 2007, Long Beach, CA
Annual Solar ABCs Stakeholder Meeting, October 17, 2008, San Diego, CA
Annual Solar ABCs Stakeholder Meeting, October 30, 2009, Anaheim, CA
Annual Solar ABCs Stakeholder Meeting, October 15, 2010, Los Angeles, CA
Annual Solar ABCs Stakeholder Meeting, October 21, 2011, Dallas, TX
Annual Solar ABCs Stakeholder Meeting, September 14, 2012, Orlando, FL
Annual Solar ABCs Stakeholder Meeting, July 11, 2013, San Francisco, CA

TASK AREA 5: *IMPLEMENTATION ACTIVITIES*

Tasks for the *Implementation Activities* are designated for the two *Implementation Activity Working Panels*. All activities and tasks are designed particularly for outreach, training, and interaction with the Solar ABCs members and PV stakeholders. These activities are critical to support growth in PV deployment in the U.S. over the next several years and their implementation will continue for the full project period.

Task 5.1: *The Code Officials Working Panel*

Objective: The *Code Officials Working Panel* focuses on outreach efforts to educate, inform, and assist public officials who establish and enforce local codes.

California Fire Guidelines

- Bill Brooks attended meetings on October 3, October 23, November 13, and December 4, 2007 and January 9 and Jan. 24, 2008organized by California Fire Marshall's Office and the California Solar Energy Industries Association to develop Guidelines for Photovoltaic Systems, which may be adopted by fire jurisdictions throughout California. Consensus on the guidelines is expected in the next quarter.

- Primary topics of discussion at these meetings were: 1.) clear walkways on rooftops; 2.) areas to ventilate roofs; 3.) methods to protect firefighters from energized conductors; and, 4.) warning signs to provide adequate warning to firefighters. The resulting guidelines from these meetings have focused on the required area on rooftops for access of firefighters to the roof and to ventilation requirements for residential and commercial rooftops.
- These requirements represent a significant improvement over the controversial requirements drafted by the City of Los Angeles. Although these new statewide requirements will impact the installation of PV systems on residential and commercial buildings, the reduced requirements will definitely help installations in the many areas where fire officials had already, or were in process of adopting the Los Angeles requirements.
- On April 30 a webinar was held to provide training on the California State Fire Marshal guidelines for PV systems. This workshop was cosponsored by IREC. Over 125 attendees for the webinar.

<u>Trainings and Workshops</u>

- Bill Brooks conducted code official training in four different locations in New Jersey attend by over 100 code officials.
- In February and March (2008), Brooks Engineering provided training seminars for contractors and code officials. Two of these were at the AEE dealer conference in Phoenix, Arizona, one at the Solar Energy International dealer conference in Fort Collins, Colorado, and one at the groSolar dealer conference in Boston, Massachusetts. Over 250 code officials and contractors attended these workshops. These trainings were partially subsidized by the Solar ABCs program.
- Provided two code official workshops in Manteca, California and Austin, Texas.
- Attended and gave a presentation at a meeting with building and fire officials in San Jose, California on December 15, 2008. Discussed PV system fire safety and installation standards. The City of San Jose, Solar America and Solar Tech sponsored the meeting.
- Provided four workshops on the National Electrical Code in Buffalo, NY, Seattle, WA, Minneapolis, MN, and Philadelphia, PA. These workshops included discussion of the draft Expedited Permit Process.
- Two training workshops were provided for code officials on PV permitting and field inspection. The two workshops took place in Kauai and Maui, Hawaii. These workshops were heavily attended with over 50 participants in each of the two workshops.
- Gave presentation on the Expedited Permit Process on October 16, 2009 at the Northeast Solar Cities Meeting in Pittsburgh. Approximately 25 people were in attendance including key building officials from the city of Pittsburgh.
- Presented information on Expedited Permit Process for PV Systems at a webinar on November 11 hosted by the Interstate Renewable Energy Council with over 150 attendees. An additional webinar on the Guidelines, hosted by Vote Solar, was held on December 10 with a similar number of attendees.
- Two day-long training workshops were provided for code officials on PV permitting and field inspection. The first workshop took place on October 7 in San Ramon, California with over 80 participants. The other workshop took place in Ontario, California with nearly 100 participants. Both of these workshops were provided for the California Building Officials (CALBO) Education Weeks. Many of the class participants were electrical inspectors with extensive experience inspecting PV systems. Other attendees were from fire departments and many questions related to the enforcement of the Cal

Fire PV Installation Guidelines were fielded at the workshops. In addition, Brooks Engineering was invited to provide a luncheon presentation for the East Bay Uniform Code Committee in Alameda, California where over 65 electrical inspectors were in attendance to learn about field inspection issues with PV systems. Three additional day-long trainings, not funded by this grant, took place on October 3, 2009 in San Mateo, California with over 30 in attendance, on November 17 in Las Vega with 20 in attendance, and in San Francisco, on December 16 with 50 in attendance in class with another 75 participating online.

- On April 1st, Brooks Engineering provided a webinar on the CalFire Solar Installation Guidelines. Over fifty people participated in the Webinar.
- On April 14-15, 2010, Brooks Engineering participated in the Solar America Cities Annual Meeting in Salt Lake City, Utah. This meeting provided outreach to these important cities about the efforts of Solar ABCs with particular focus on Permitting and Fire Code related activities. While the focus was to provide information on Task 3 activities, information on other Solar ABCs efforts was provided.
- On April 21, 2010, a presentation was made at the SolarTech Summit in San Ramon, California on the Expedited Permit Process. Interest continues to grow on this item as more communities begin to implement the recommendations.
- One day-long training workshop was provided for code officials on PV permitting and field inspection on April 28th in Portland, OR.
- Brooks provided a permitting training session on October 8, 2010 in San Ramon California and another session on November 16,2010 for Electrical Code Officials. This training discussed the updates to the Expedited Permit Process.
- Provided presentation and sat on panel at SolarTech meeting near Pasadena, California on February 10, 2011 to discuss the Expedited Permit Process and how to help DOE reduce permitting soft costs.
- Participated in panel at SolarTech Solar Summit in San Jose, California on March 29, 2011 to discuss the need for the PV industry to work with local jurisdictions to help them reduce their costs by providing quality permit packages and installations.
- Brooks presented an all-day training session for the California Building Officials annual training week on September 28, 2011 in San Ramon, California. Over 80 inspectors and building officials were in attendance.
- Organized webinar on September 20, 2011 on changes to the 2012 I-Codes that affect photovoltaics. 175 stakeholders participated in this webinar.
- Brooks provided a short 2-hour presentation on May 15 to the Marin County building and fire officials and discussed rooftop disconnects that have been required by various Marin fire departments over the past several years. Over 25 officials were in attendance.

- Prepared a report on jurisdiction use of electrical codes

- The On December 3, Brooks Engineering participated in a day-long seminar organized by SolarTech to discuss ways of improving permitting of solar systems. Approximately 65 participants attended the seminar and good ideas and input was provided by the presenters and participants for improving permitting in the San Francisco Bay Area.
- On March 17, 2010, Brooks Engineering represented SolarABCs at a meeting of the NFPA Fire Service Workshop on Solar Panels. The meeting included a total of 25 high level individuals from several fire services, NFPA staff, electrical code officials, and solar industry representatives. The results of the workshop will be included in a report to be released by The NFPA Fire Research Foundation.

- Brooks worked with several rooftop solar challenge awardees, including Tennessee, Chicago, Nevada, Wisconsin, Bay Area, Solar Sonoma, and Pittsburgh, to assist them in implementing simplified permitting and inspection procedures.
- Colleen Kettles worked to resolve some restrictive codes and permitting requirements in New Jersey related to solar access.
- Brooks participated in SEIA Codes and Standards meetings in San Francisco on March 20-21, 2013. These sessions primarily focused on the solar industry's influence in the 2015 International Fire Code (IFC) and the 2015 International Residential Code (IRC). As a result of these strategy sessions, Brooks was asked to travel to Chicago the following week to represent the solar industry in the Fire Code Action Committee (FireCAC) meetings on March 26-27, 2013.
- Brooks continued to work with the FireCAC to get the 2015 IFC changes supported by the solar industry approved at the code making hearing in Dallas, Texas the week of April 22. Brooks attended Dallas hearings on April 23-24, 2013 and was instrumental in getting all requested changes implemented into the 2015 IFC. Travel and half of time was covered by SEIA.

Deliverables:
Stakeholder Meeting August 20, 2008
Participated in six meetings in 2007 and 2008 organized by California Fire Marshall's Office and California Solar Energy Industry Association to develop guidelines for PV systems
Participated in NFPA Fire Service Workshop on Solar Panels
Code Official trainings (many)
Solar ABCs White Paper: Impacts of Photovoltaic Installations of changes to the 2012 International Codes
Stakeholder Meeting December 7, 2007
Stakeholder Meeting March 25, 2008
Annual Solar ABCs Stakeholder Meeting, September 27, 2007, Long Beach, CA
Annual Solar ABCs Stakeholder Meeting, October 17, 2008, San Diego, CA
Annual Solar ABCs Stakeholder Meeting, October 30, 2009, Anaheim, CA
Annual Solar ABCs Stakeholder Meeting, October 15, 2010, Los Angeles, CA
Annual Solar ABCs Stakeholder Meeting, October 21, 2011, Dallas, TX
Annual Solar ABCs Stakeholder Meeting, September 14, 2012, Orlando, FL
Annual Solar ABCs Stakeholder Meeting, July 11, 2013, San Francisco, CA

Task 5.1.3: Electrical Code and Fire Official Permitting and Guidelines Development

Solar ABCs will develop electrical code permit application checklist and a draft guidebook for fire officials to make clear the processes for implementing safe standards for PV system deployment that eliminate often burdensome and inconsistent processes currently in use. Training for both professional groups will be provided.

- Bill Brooks of Brooks Engineering and Howard Barikmo attended the First Workshop of Solar on Fire in Aachen, Germany at Photon Magazine's headquarters. This two-day meeting brought together Fire Officials from Germany, Italy, and the United States, along with representatives from the insurance industry. Nearly 75 participants, mostly members of the PV industry, met to discuss the issues related to hazards of PV systems to property and fire fighters. Several solutions were discussed to help mitigate these hazards, but the discussion was directed by representatives of Photon International Magazine toward module control systems. This emphasis on "smart PV modules" is a

logical direction for the future of the PV industry, but it is unclear how the transition to smart modules should be made.

- A meeting was held on October 26, 2009 with Michael Schmela, editor of Photon International Magazine, to discuss next steps related to the PV:SAFETY group that Photon proposes to help form. Mr. Schmela requested that Brooks Engineering consider heading this group since the European participants are having trouble agreeing on what needs to be done. It was suggested that SolarABCs may be the right entity to move the process forward and engage the various stakeholders in discussions on fire safety issues related to PV.
- On March 15, 2010, Brooks Engineering facilitated a group of 25 participants brought together by the SolarTech Installation Subcommittee to discuss the need to improve the codes and standards that relate to microinverters.

- Bill Brooks was appointed as one of eight members of a CalFIRE cadre to develop training materials for firefighters working with PV systems. A total of nine days was spent on this effort during this quarter.
- Updates to the Expedited Permit Process Study Report
- These updates will include revising the weather data to the latest ASHRAE data set and adding a sample electrical diagram for microinverters and ac modules. A draft will be completed by August 2010.
- Explanatory document for the California Fire Marshal Solar PV Installation Guidelines.
- Brooks participated with UL's meeting for fire testing to illustrate hazards to firefighters on July 16, 2010.
- Brooks participated with UL's meeting for fire testing to illustrate hazards to firefighters on November 17, 2010. This meeting was held at Northbrook, Illinois and included demonstrations of several of the tests being conducted as part of the project.
- Brooks coordinated with Photon Magazine on December 15 to develop an agenda for the upcoming PV: SAFETY conference on February 15, 2011 in San Francisco, California.
- 1Q11
- Brooks convened the Grounding task force of the UL1703 STP with assistance from UL and secretary Greg Ball of BEW Engineering. Brooks revised the proposed language for edits to the UL1703 standard related to bonding, grounding and grounding devices.
- Brooks helped coordinate the Photon International PV:SAFETY conference and provided two presentations with on February 15, 2011 in San Francisco, California.
- Brooks provided presentations and participated in panel discussions at the Photon International PV Inverter Conference on April 12, 2011 and the PV:SAFETY conference on April 13, 2011 in Berlin, Germany.
- Brooks witnessed the testing performed by UL related to firefighter safety in Philadelphia, Pennsylvania on April 21, 2011.
- Brooks participated in the UL 1741 STP meeting April 26-27, 2011 and made a detailed presentation about the problems with current ground-fault protection equipment in larger PV systems. Brooks is working with UL to convene a task group to address fire-related concerns of existing ground-fault sensing methods supported by the UL1741 standard.
- Brooks convened the NFPA Firefighter Safety Task Force meeting on June 14 at the request of NFPA's National Electrical Code (NEC), Code Making Panel 4. Participants discussed the major issues that face firefighters and discussed proposal options for the 2014 NEC. The primary outcome was a recommendation to draft a proposal to require

commercial rooftop PV systems to remotely de-energize combiner box feeder circuits and residential PV systems to de-energize PV source circuits to the module level.

- Brooks participated in an invitation-only California Governor's task force meeting on barriers to the development of renewable energy in California. The California State Fire Marshal, Tonya Hoover, extended the invitation for the two-day meeting that took place at UCLA July 25-26, 2011.
- Brooks worked with the Governor's Office in California to help finalize a series of statewide, standardized permitting requirements for California to help ensure that the state's requirements are consistent with the Solar ABCs Expedited Permit Process. Brooks met directly with the developers of the California process at their facilities in Los Angles to resolve some important differences.
- On behalf of Solar ABCs, attended SunShot Conference in Denver, Colorado and met with several Rooftop Solar Challenge awardees to help them with details regarding implementation of simplified permitting and inspection processes in their regions.

Solar ABCs Report published:

Understanding the CAL FIRE Solar Photovoltaic Installation Guideline
Author: Bill Brooks, Brooks Engineering
This report provides the context and background information for the California Department of Forestry and Fire Protection's (CAL FIRE's) Solar Photovoltaic Installation Guideline (Guideline), which was released on April 22, 2008. In May 2010, the International Code Council (ICC) approved a revised version of the Guideline for inclusion in the 2012 version of the International Fire Code
(IFC). This report provides information about how the task force developed the Guideline and why task force members recommended that photovoltaic (PV) systems be designed and installed to accommodate firefighting operations.

Deliverable:
Solar ABCs Report: Understanding the CAL FIRE Solar Photovoltaic Installation Guideline

Task 5.2: *The Regulators, State Energy Offices, Legislatures Working Panel*

Objective: The *Regulators, State Energy Offices, Legislatures Working Panel* will support the activities of state and local offices responsible for, but often unprepared for, the development and execution of statutory regulation governing PV deployment.

- On July 20-23, 2008, Jason Keyes, Kevin Fox and Michael Sheehan attended the NARUC Summer Meetings in Portland, OR. This event provided the opportunity to meet Commissioners and Staff and to start developing communication links with them. Our goal is to get on the agenda for their Winter Meeting (February 2009) to discuss the 3 Studies. This July meeting allowed for introductions of the Team as well as of the study areas.
- On August 5 and 6, 2008, Jason Keyes and Kevin Fox attended SEPA's Metering & Performance Monitoring Exposition and Workshop on integrating PV with utility smart meters and intelligent grid systems. The Conference took place in Oakland, CA.
- On August 21, 2008, Keith McAllister gave a presentation on an IREC phone seminar based on the AMI draft study. Regulators, Legislators and State Energy officials were part of the 229 people who participation in the phone seminar.

- On October 8, 2008, Michael Sheehan spoke at the Edison Electric Institute's Transmission, Distribution and Metering Fall Conference, which was held in Seattle, WA. Mike talked about best practices as they relate to net metering and interconnections. He discussed the Standards Comparison Report and the Utility External Disconnect Switch (UEDS) study.
- On October 13, 2008, three Solar ABCs presentations were made at IREC's Annual Meeting in San Diego. Over 130 state stakeholders attended this all-day meeting. Keith McAllister talked about the Advance Metering Infrastructure (AMI) study. Mike Sheehan made a presentation on the Utility External Disconnect Switch study and Jason Keyes and Kevin Fox discussed the Model Interconnection Standards Comparison study.
- On February 2-4, 2009, Keith McAllister attended the NASEO (state energy offices) conference in DC.
- On February 16, 2009, Jason Keyes made a presentation at the NARUC (state regulators) Winter Committee Meetings in DC to the Committee on Energy Resources and the Environment (ERE) on major issues in net metered solar energy. The conference was held February 15-18, 2009. There was discussion with a number of State Commissioners including Rebecca Wagner (NV), Kris Mayes (AZ), Ron Allen (UT), Robert Pickett (AK - chair), Carlito Calaboso (HI - chair), Jim Gardner (KY), Pat Oshie (WA, chair of ERE) and Lawrence Chaset (CPUC staff).
- Stephen Barkaszi participated at the meeting of Broward/Miami-Dade Board of Rules and Appeals (BORA) Subcommittee in Miami, FL and Plantation, FL on February 9 and March 23, 2009, respectively. Issues associated with permitting, installation and inspection of solar systems were discussed at these meetings. FSEC approval of solar equipment was discussed as part of the permitting process and the applicability of the electrical components of the expedited permitting process was well received.
- On behalf of IREC and the Solar ABCs, the North Carolina Solar Center attended the SEPA "Solar Options for Low Cost Utilities" meeting on April 13 and 14, 2009 in Knoxville, TN. The conference was focused at SEPA's Central Region. Over 100 attendees representing electric utilities, distributors and manufacturers, universities and research organizations such as EPRI, and other stakeholders. The presentation gave the general overview of the Solar ABCs.
- On Thursday May 14, 2009, Jason Keyes (representing Michael Sheehan) made a presentation on the Utility External Disconnect Switch: Practical, Legal, and Technical Reasons to Eliminate the Requirement Study at the ASES Solar 2009 Conference in Buffalo.
- NARUC Summer Committee Meetings (Seattle): NARUC held its Summer Committee Meetings in Seattle on July 19-22. IREC and the North Carolina Solar Center were in attendance and Kevin Fox had an opportunity to deliver a presentation to a group of commissioners and staff at a breakfast meeting on July 22 hosted by the Solar Alliance.
- SEPA Utility Solar Conference (San Jose): SEPA held its Utility Solar Conference in San Jose on July 28-29. The SEPA conference provided a forum for utilities to share information and exchange ideas on how to develop a viable long-term solar strategy. Kevin Fox appeared on a panel focused on interconnection and billing issues.
- SolarTech Interconnection Symposium (San Jose): On July 30, SolarTech held an Interconnection Symposium in conjunction with the SEPA Utility Solar Conference in San Jose. The SolarTech symposium focused on identifying opportunities to improve cooperation between the solar industry and utilities in facilitating solar system interconnection. Jason Keyes represented IREC at the conference and delivered the keynote address to Symposium attendees.

- IREC's Annual Meeting: As part of our outreach strategy, Solar ABCs was on the agenda at the IREC Annual Meeting on October 26, 2009 in Anaheim, CA. Keith McAllister presented a 30-minute slide presentation that reviewed the Solar ABCs mission, participating organizations, past reports, and studies currently underway.
- California Workshop: On November 20, 2009, Joe Wiedman attended a workshop concerning the implementation of California's NEM cost-benefit evaluation.
- February 10, 2010. Solar ABCs Webinar on the Utility External Disconnect Switch Study with Michael Sheehan and Michael Coddington.
- February 12, 2010. Presentation at the Law Seminar's International in Las Vegas - Today's Electric Utility Rate Cases Current Issues and Strategies- on the rate impact of net metering - Jason Keyes.
- February 4-5, 2010. IEEE 1547.7 meeting in Las Vegas (System impacts of DG) - Michael Sheehan.
- February 15-17, 2010. Attended NARUC's Winter Meeting in Washington, DC - Jason Keyes.
- March 24, 2010. Attended California Public Utility Commission's Workshop - Joe Wiedman.
- ASES Solar Conference: Kevin Fox, Joe Wiedman and Jason Keyes participated in Solar 2010, the annual conference of the American Solar Energy Society in Phoenix, Arizona, May 19-21. Mr. Fox gave a presentation reviewing much of the material covered in IREC's Solar ABCs report on policy alternatives. Mr. Keyes moderated a panel related to valuing the benefits of distributed generation, which is directly related to the Solar ABCs report on the rate impact of net metering. Travel expense was attributed to IREC's DOE contract for state outreach as was much of their time at the conference but this was an outreach effort for Solar ABCs as well.
- Jason Keyes, Kevin Fox and Laurel Varnado attended the NARUC Summer Meetings on July 18-21, 2010 in Sacramento. Kevin Fox spoke on The Sustainable Electricity Future: The Role of Distributed Renewable Power Resources.
- Mike Sheehan attended the IEEE 1547.7 Working Group (WG) meeting August 10-11, 2010. IEEE P1547.7 when completed will describe the criteria, scope, and extent for engineering studies of the impact on area electric power systems of a distributed resource or aggregate distributed resource.
- The inaugural meeting of the IEEE 1547.8 Working Group was called to order on August 12. Mike Sheehan attended. There were over 75 people at this meeting. IEEE 1547-2008 was originally developed with low grid penetration levels and with no vision of the Smart Grid or Plug in Electric Vehicles or Energy Storage. The proposed method of updating IEEE 1547-2008 with the IEEE 1547.8 process will require each jurisdiction to establish specific procedures and rules to facilitate the DR interconnection. In addition to these procedures and rules, other business issues may need to be considered (VAR compensation, peak shaving and system support) and addressed. Mr. Sheehan has volunteered for two writing groups (DR required to see faults and increase the standard to 20 MVA) and will be reviewing the entire document looking for changes that may have an influence on existing interconnection rules.
- Jason Keyes participated in a rate design workshop in Golden, Colorado that was sponsored by the National Renewable Energy Laboratory on September 16, 2010. The topic of that meeting relates directly to one of our ABCs studies - the Rate Impact of Net Metering - as rate design related to solar energy is pursued on the one hand to incentivize solar installations, and on the other, to assure that utility ratepayers generally are not subsidizing those customers who install on-site generation. Attendees

included the leading researchers in the area from the DOE, industry, NREL, and Lawrence Berkeley National Laboratory.

- Kevin Fox prepared for participation in an Energy Symposium at the University of San Francisco that will be held on the first day of the next quarter. Mr. Fox will be participating on a regulatory panel with representatives from PG&E, the California Public Utilities Commission and a California ratepayer advocacy group, TURN. The panel will focus on identifying regulatory barriers and opportunities for developing robust markets for Solar PV, a topic that fits squarely within the scope of a recent Solar ABCs report on which Mr. Fox is lead author - Sustainable, Multi-Segment Market Design for Distribute Solar Photovoltaics (see below for more details).
- Kevin Fox made a presentation at the University of San Francisco Clean Technology Symposium. Mr. Fox appeared on a panel titled "Key Issues in Distributed Generation: Regulatory Incentives and Authority." He focused on advancing a vision of multi-segment market design for solar PV that would allow PV systems to be deployed across a full range of potential markets. The panel discussion did not allow for PowerPoint presentations to be used.
- On October 5, Michael Sheehan presented the findings of the FERC SGIP report to the EEI fall meeting in Denver.
- A number of presentations were made at IREC's Annual Meeting on October 11, 2010 in L.A. Jason Keyes, Kevin Fox and Joe Wiedman (Keyes and Fox, LLP); Commissioner Jason Marks (New Mexico Public Regulation Commission); Tommy Cleveland (North Carolina Solar Center); Adam Browning (Vote Solar); and Michael Sheehan (IREC) shared the purpose, activities and accomplishments of IREC's Solar ABC's work
- A presentation was given at the Future Energy Conference in Seattle on November 9, 2010 at the request of Seattle City Light. That presentation related to interconnection issues and was attended by approximately 80 people, including Washington utilities commissioner Phillip Jones and Washington House energy committee legislative aide Scott Richards, along with many utility personnel. The content of the presentation related to the ABCs study on interconnection procedures that Keyes & Fox completed last year, and a link to the study was included. Jason Keyes gave this presentation.
- A presentation was made on December 8, 2010 at the Fourth International Conference on Integration of Renewable and Distributed Energy Resources and again related to interconnection procedures and referenced the ABCs paper. Jason Keyes was invited to give the presentation by New Mexico utilities commissioner Jason Marks and there was an audience of approximately 250 people.
- NARUC Winter Meetings. Joe Wiedman attended the NARUC Winter Meetings and the NARUC National Electric Forum in Washington D.C. from Feb. 13-17, 2011. During his time at the conference, Mr. Wiedman met with commissioners and staff from various commissions including Hawaii, California, Arizona and Delaware and government agencies including the Rural Utilities Service and the D.C. Council of Governments. During his conversations, Mr. Wiedman discussed findings from various reports as relevant including the Interconnection comparison study, Utility External Disconnect report, the Multisegment Market Design report, and preliminary findings from the Rate Impacts report. No formal presentations were given.
  EUCI Conference. Kevin Fox attended an EUCI conference in Los Angeles on January 30-31, 2011 on Meeting RPS Through Large-Scale PV. Mr. Fox gave a presentation on the Multisegment Market Design paper. Numerous utilities were in attendance from California, Arizona, New Mexico and other states. Also in attendance were commissioners from Arizona and Nevada.

- IEEE 1547.8 Working Group. Mike Sheehan participated in several conference calls on Section 4.2.1 of draft IEEE 1547.8 Working Group draft and also attended the IEEE 1547.8 meeting on February 10-11, 2011 in Las Vegas.
- CPUC. On March 4, 2011, Mike Sheehan presented alternatives and proposed next steps for the existing barrier at the California Re-DEC meeting on the 15% Line Section. (Re-DEC = Renewable Distributed Energy Collaborative)
- On April 13, Mike Sheehan gave a presentation at the Utility Wind Integration Group meeting in Kansas City on the FERC Small Generator Screen of 15% line section limit.
- Mike Sheehan and Tommy Cleveland wrote a technical paper for the ASES May Solar Conference entitled Review of the Federal Energy Regulatory Commission Small Generator Interconnection Procedures (FERC SGIP) Technical Screens. This paper was based on their Solar ABCs study.
- Mike Sheehan attended the DOE High Penetration Solar Deployment Workshop in Sacramento, California on June 13, 2011.
- Mike Sheehan contributed in the development of the next draft of IEEE 1547.8 Section 4.2.1 4.2.2. The significance of this draft is it has provisions on allowing higher penetrations of DG beyond the current 15% line section limit.
- Joe Wiedman attended two net metering workshops in Richmond, Virginia at which the rate impacts issue was a primary issue. (The cost of Mr. Wiedman's time was charged to another grant). The first workshop was held in April and the second one in early May.
- Joe Wiedman and Larry Chaset prepared for and participated in the NARUC summer meetings, particularly for the discussions of energy storage with renewable energy and to continue outreach on the Rate Impacts paper during stakeholder events.
- Kevin Fox participated in the California Governor's Energy Conference for the development of local energy resources. His covered both market design and interconnection procedures, two topics on which he has prepared Solar ABCs reports.
- Kevin Fox also participated in Intersolar in San Francisco on July 11 discussing PV market design.
- Kevin. Fox participated in the U.S. DOE's Southeast Solar Bootcamp in Atlanta on August 29-30 and Chris Cook participated in the Northeast Solar Bootcamp on August 24-25; both talked about interconnection and net metering best practices, which are topics covered in IREC's various Solar ABCs reports.
- Brooks attended a meeting on March 28, 2012 in Sacramento, California, hosted by the Governor’s Office in California to help finalize a series of statewide, standardized permitting requirements for California that are largely based on the Solar ABCs Expedited Permit Process.

<u>Narrated PowerPoint Presentations</u>

Created interactive web-based presentations and posted to the Solar ABCs web site
Solar Access
http://www.solarabcs.org/solaraccess/Solar%20Access%20Law.htm

Utility External Disconnect Switch
http://www.solarabcs.org/utilitydisconnect/Solar_ABCsUEDS_presentation.htm

AMI and Renewable Energy
http://www.solarabcs.org/advancedmetering/presentation/AMIandRenewableEnergy.htm

Subtask 5.2.2 Coordination Activities.

The panel leaders will develop and deliver workshops (one per year for each of the five project years) covering the topics of PV regulations for state and local governments. Panel members will make presentations addressing topics such as 'best-practices', solar-access rights, and solar permitting at two national conferences (years 2-5).

See Task 5.2 Report.

Stakeholder meetings on February 19, 2010 and March 7, 2010
Annual Solar ABCs Stakeholder Meeting, September 27, 2007, Long Beach, CA
Annual Solar ABCs Stakeholder Meeting, October 17, 2008, San Diego, CA
Annual Solar ABCs Stakeholder Meeting, October 30, 2009, Anaheim, CA
Annual Solar ABCs Stakeholder Meeting, October 15, 2010, Los Angeles, CA
Annual Solar ABCs Stakeholder Meeting, October 21, 2011, Dallas, TX
Annual Solar ABCs Stakeholder Meeting, September 14, 2012, Orlando, FL
Annual Solar ABCs Stakeholder Meeting, July 11, 2013, San Francisco, CA

Presentations:

1. NARUC 08 Summer Committee Meeting - July 2008
2. AMI Presentation-IREC Phone Seminar - August 2008
3. EEI T&D Meeting - October 2008
4. IREC Annual Meeting - October 2008
5. NASEO Winter Meeting - February 2009
6. NARUC Winter Committee Meetings - February 2009
7. SEPA Utility Regional Conference - April 2009
8. ASES Solar ABCs Session - May 2009
9. NARUC Summer Committee Meetings, Seattle - July 19-22, 2009
10. SEPA Utility Solar Conference, San Jose - July 28-29, 2009
11. SolarTech Interconnection Symposium, San Jose - July 30, 2009
12. IREC Annual Meeting - October 26, 2009
13. California Public Utilities Commission - November 20, 2009
14. Presentation at Law Seminar - February 12, 2010
15. IEEE 1547.7 Meeting - February 4-5, 2010
16. NARUC Winter Committee Meeting - February 15-17, 2010
17. CPUC Workshop - March 24, 2010
18. ASES Solar Conference - May 19-21, 2010
19. High Penetration PV Meeting - May 20, 2010
20. Utah Public Utilities & Transportation Interim Committee. June 23, 2010
21. NARUC Summer Committee Meetings, Sacramento, CA. July 18-21, 2010
22. IEEE 1547.7 and 1547.8 Working Group Meetings. San Francisco. August 10-12, 2010
23. Rate Design Workshop. Golden, CO. September 16, 2010
24. Clean Technology Symposium. San Francisco, CA. Fall 2010
25. EEI Fall Meeting. Denver, CO. October 5, 2010
26. IREC Annual Meeting. Los Angeles, CA. October 11, 2010
27. Future Energy Conference. Seattle, WA. November 9, 2010
28. 4th International Conference on Integration of Renewable and Distributed Energy Resources. December 8, 2010
29. EUCI Conference. Los Angeles, CA. January 30-31, 2011

30. IEEE 1547.8 Meeting. Las Vegas, NV. February 10-11, 2011
31. NARUC Winter Meetings. Washington, DC. February 13-17, 2011
32. CPUC Re-DEC Meeting. San Francisco, CA. March 4, 2011
33. Utility Wind Integration Group Meeting. Kansas City, MO. April 13, 2011
34. ASES Solar Conference. Raleigh, NC. May 2011
35. DOE High-Penetration Solar Deployment Workshop. Sacramento, CA. June 13, 2011
36. Net Metering Workshop. Richmond, VA. April 20-21, 2011
37. Net Metering Workshop. Richmond, VA. May 5-6, 2011
38. Intersolar Conference. San Francisco, CA. July 11, 2011
39. NARUC Summer Committee Meetings. Los Angeles, CA. July 18-19, 2011
40. California Governor's Energy Conference, Los Angeles, CA. July 25-26, 2011
41. DOE's Southeast Solar Bootcamp. Atlanta, GA. August 29-30, 2011
42. DOE's Northeast Solar Bootcamp, New York. August 24-25, 2011

Task 5.2.4: Analysis of Net Metering and Interconnection Issues

The Gap Analysis conducted identified several areas of concern. Priorities were defined by stakeholders to be: a) the economic impact on rate payers of net metering and new tariff structures developed for net metering situations, b) the impacts of net metering on utility revenues, and c) the potential advantages and disadvantages to utilities and rate payers of replacing net metering and associated tariffs with "feed in" tariffs. Solar ABCs will respond to these concerns with publicly distributed study reports that address the following:

1. the economic impact of net metering in eight states, focusing on the impacts on rate payers and on effectively assessing the true value to utilities in those states.
2. a comparison of new tariff structures developed in response to net metering with replacement of net metering by "feed in" tariffs (and other production based incentives). This will include the impacts of the different options on tracking, billing, financial incentives and final payouts.
3. Response to new tariff structures and incentive programs over the next two years that will necessitate re-evaluation of existing Interconnection and Net Metering guidelines to effectively deploy PV systems without burdensome, legacy processes and procedures.

Solar ABCs published two reports:

Sustainable, Multi-Segment Markets for Solar Distributed Generation

Authors: Kevin Fox, Keyes & Fox and IREC, Laurel Varnado, North Carolina Solar Center
This report discusses the important differences between retail and wholesale photovoltaic (PV) markets and provides examples of policies that have been implemented in the United States in both of these markets. The Retail Market Policies section discusses policies that enable end-use retail electric customers to invest in PV systems to meet some or all of their electricity needs. The
Distributed Solar Photovoltaics Wholesale Market Policies section, by comparison, discusses policies that enable small and medium scale project developers to develop distributed generating facilities that will serve nearby retail electric utility load.

A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering

Authors: Jason Keyes and Joe Wiedman, Keyes & Fox and IREC
This report presents a thorough examination of the impact of net-metered solar facilities on non-participating customers' utility rates. It puts forward a methodology for the valuation

of net energy metering (NEM) focused on best practices. Information in this report will assist state policy makers, utility planners, utility regulators, and all other stakeholders who must evaluate the potential rate impacts of NEM in their states. The report centers on the impact of net-metered solar facilities (because solar facilities comprise the majority of net-metered generation) and does not address economic impacts, environmental impacts, or impacts on participating customers investing in distributed generation (DG) resources. The report also includes an analysis of the methodology used to determine rate impacts but does not undertake a review of any particular state renewable energy program.

Deliverables:
Solar ABCs Report: Rate Impact of Net Metering
Solar ABCs Report: Sustainable Multi-Segment Market Design for Distributed Solar Photovoltaics

Task 5.2.5: Review of FERC's SGIP Interconnection Screens

Gap Analysis identified that FERC's Small Generator Interconnection Procedure (SGIP) contains a series of technical screens for interconnection of generating facilities up to two megawatts that may be more stringent than necessary. Solar ABCs will develop draft revisions for consideration by FERC to simplify the technical screens currently in use for interconnection of small generation facilities.

Solar ABCs held the following webinars to receive stakeholder input on the topic:

- A stakeholder meeting/webinar for the FERC SGIP study was held on December 2, 2009. 15 people participated. The plan for the study was presented and stakeholders provided comments.
- A stakeholder meeting for Review of the FERC SGIP Screens paper was held on April 14, 2010. Forty-seven people attended.
- A second stakeholder meeting for collecting comments on Review of the FERC SGIP Screens paper draft was held on June 17, 2010. Thirteen people attended

Solar ABCs published the following report:

Updated Recommendations for Federal Energy Regulatory Commission Small Generator Interconnection Procedures Screens
Authors: Michael Sheehan, IREC and Tommy Cleveland, North Carolina Solar Center
This report is a status assessment of the Federal Energy Regulatory Commission (FERC) Small Generator Interconnection Procedures (SGIP) fast track technical screens. The North Carolina
Solar Center and the Interstate Renewable Energy Council led the review and development of suggested updates to the FERC SGIP screens and the 10kW Inverter Process after conducting an interactive development process based on a questionnaire of small generator interconnection subject matter experts (SMEs).

Deliverable:
Solar ABCs Updated Recommendations for Federal Regulatory Commission Small Generator Interconnection Procedures Screens

APPENDIX

Solar American Board for Codes and Standards

Gap Analysis Final Report

July 28, 2008

Summary

The Solar America Board for Codes and Standards (Solar ABCs) Gap Analysis process reviewed the current state of the major codes and standards that bear on PV, identified major gaps that exist in the current work on codes and standards and prioritized these to become a strategic plan for the development of the Solar ABCs Annual Work Plan for Year 2 and future years.

From topics suggested by stakeholders, the Solar ABCs Steering Committee identified the following high priority topics to be addressed:

- Standardization of module power rating
- System Energy Performance Standard
- Standards to certify the accuracy of inverter meters
- Accelerated life testing for safety, reliability and durability of modules and the components used in modules
- PV Module frame grounding issues
- Roof-top PV module-specific fire research, testing and ratings systems
- National Fire Safety Guidelines for roof-top PV systems
- Revise building codes to address PV specifically
- Review and suggest updates to FERC interconnection screens
- Rate Impact of Net Metering

Many of the proposed activities will not happen without new funding from the U.S. Department of Energy.

Solar ABCs identifies current issues, establishes a dialogue among key stakeholders, and catalyzes appropriate activities to support the development of codes and standards that facilitate the installation of high quality, safe photovoltaic systems. It serves as a centralized repository for such documents, regulations, technical and "best practices" materials. It makes all materials and information easily accessible to the public and stakeholders.

Introduction

The Solar America Board for Codes and Standards (Solar ABCs) Gap Analysis process reviewed the current state of the major codes and standards that bear on PV, identified major gaps that exist in the current work on codes and standards and prioritized these to become a strategic plan for the development of the Solar ABCs Annual Work Plan for Year 2 and future years.

This report summarizes the method used to conduct the gap analysis, lists the potential topics identified, and establishes the priority topics for future work by Solar ABCs. Many of the proposed activities will not happen without new funding from the U.S. Department of Energy.

The Solar ABCs identifies current issues, establishes a dialogue among key stakeholders, and catalyzes appropriate activities to support the development of codes and standards that facilitate the installation of high quality, safe photovoltaic systems. It serves as a centralized repository for such documents, regulations, technical and "best practices" materials. It makes all materials and information easily accessible to the public and stakeholders.

The Solar ABCs changes the practice of developing, implementing, and disseminating solar codes and standards in the following ways:

- By providing formal coordination in the planning and revision of separate, though interrelated, solar codes and standards
- By providing access for stakeholders to participate with members of standards making bodies in setting national priorities on technical issues
- By developing a centralized repository for collection and dissemination of documents, regulations, and technical materials related to solar codes and standards
- And by creating a centralized home for three key technical services: a) generating consensus 'best practices' materials and disseminating such materials to utilities, state and other regulating jurisdictions, b) answering code-related questions (technical or statutory in nature), c) providing feedback on important related issues to DOE and government agencies.

The Solar ABCs works through Coordination, Implementation and Study Panels.

Method

The Gap Analysis was a major project for the Solar ABCs Steering Committee during the first year of the project. Stakeholders provided topics for consideration, the Advisory Committee and Steering Committee refined and prioritized the list of topics, and the Steering Committee developed the final list of high priority Gap Analysis topics.

Solar ABCs was launched with a stakeholder meeting on September 27, 2007 in Long Beach, California. Over 200 people attended this meeting including representatives from the solar industry, utilities, suppliers, and other interested stakeholders. During that meeting,

participants learned about the first year activities of Solar ABCs. In addition, stakeholders were asked for their input on gaps or items that need improvement in the codes and standards processes related to photovoltaics. These suggested topics became the start of the Solar ABCs Gap Analysis Topic List.

Solar ABCs panels held Stakeholder Meetings in December 2007 and January 2008 and received additional suggestions for topics. As the Solar ABCs became known, additional stakeholders submitted proposed topics directly to the Project Administrator.

The Project Administrator compiled the list and sent it to both the Steering Committee and the Advisory Committee for review and discussion. These discussions led to combining topics, adding topics, and reorganizing the way the topics were presented in order to facilitate better review and prioritization. The final list of proposed Gap Analysis topics is included in Appendix A.

The Advisory Committee and Steering Committee each reviewed and prioritized the Gap Analysis list. The Project Administrator compiled the results.

Finally, the Steering Committee conducted a day and a half meeting to prioritize the Gap Analysis topics. The Steering Committee reviewed the individual rankings, discussed, and approved a list of high priority Gap Analysis Topics. Then the Steering Committee developed detailed suggestions for the activities needed for each of the high priority topics.

The Gap Analysis Process was led by the Solar ABCs Steering Committee and managed by the Solar ABCs Project Administrator, Larry Sherwood. The Steering Committee includes one representative from the following organizations: Arizona State University, BEW Engineering, Brooks Engineering, Florida Solar Energy Center, Interstate Renewable Energy Council, National Renewable Energy Laboratory, New Mexico State University, North Carolina Solar Center, PowerMark, Sandia National Laboratories, Sunset Technology, Underwriter Laboratories, and U.S. Department of Energy.

The Solar ABCs Advisory Committee includes: Jim Baak, Pacific Gas & Electric (also representing Solar Electric Power Association); Suzanne Borek, New Jersey Department of Community Affairs; Nick Chaset, California Public Utilities Commission; Adam Detrick, SunPower Corp.; Mark Dougherty, Long Island Power Authority; Smita Gupta, California Energy Commission; Edwin Iracki, DuPont; Tom McCalmont, ReGrid Power; Rhone Resch, Solar Energy Industries Association; Peter Varadi, Consultant; and Donald Warfield, BP Solar.

High Priority Gap Analysis Topics

Photovoltaic System Energy Rating

Objectives:
The tentative objectives are divided into the short-term (one year) objective and the long-term (3 to 5 Years) objective, as follows:

- The short-term objective is to develop and validate the procedure for *Simplified PV System Energy Rating* to provide annual system energy output for typical PV systems (focusing on residential and small commercial applications) using simple hourly simulation models.
- The long-term objective is to develop a process for validating PV models and pursue the process as a Standard.

Tasks:

Task 1: Simplified PV System Energy Rating

The procedure for determining the annual energy output of flat-plate grid-connected residential PV systems (up to 10 kWp), and possibly of small commercial PV systems (up to 100 kWp), under "optimal" conditions will be developed and validated to provide an estimate of PV system performance to homeowners, businesses, government and other renewable energy rebate granting agencies, just like the "EPA Vehicle Gas Mileage" or air-conditioners SEER. The procedure will be validated by the Project partners by comparing the predicted and actual measured PV system performance for at least three different module technologies (tentatively selected: crystalline silicon, multi-junction amorphous silicon, and CdTe) and at least three distinct climatic locations (tentatively selected: Florida, California, and Colorado/New Mexico/Arizona). This procedure can, then, be recommended by PowerMark Corporation to its approved certification agencies, such as FSEC, NMSU, and others to be used for certifying the annual energy output of specific flat-plate, grid-connected residential and small commercial PV system electrical designs. PowerMark approved certification agencies will provide the certified estimate of annual system energy output to the system designers, vendors, integrators, homeowners, businesses, government and other rebate granting agencies, at a nominal fee as requested.

The essential features of this task are:

1. PV module operational characteristics at different operating temperatures and irradiance levels will be input from the results of Gap Analysis Topic # 105 PV Module Power Rating/IEC 61853. IEC Technical Committee 82, Working Group 2 is currently working on *PV Module Power and Energy Rating* standard, IEC 61835, for flat plate PV modules. The draft of Part 1 on Power Rating is now under review by National Committees, including the US TAG. Part 2 on measurement techniques is expected to be circulated for review within 3 months. Part 3 on the methodology of energy calculation will be circulated for review by the end of 2008. This set of documents will form the basis of the procedure for *Simplified PV System Energy Rating*, when used in combined with PV system electrical design specifics and inverter operational characteristics, as described below. Solar ABCs Project partners will follow the progress of these documents and incorporate the methodology of the IEC 61853 in the procedure for *Simplified PV System Energy Rating*. In addition, FSEC

and ASU will validate the procedures in IEC 61853 by performing the test protocol on a representative set of module types.
2. Simple hourly simulation models like PV Watt, PV-DesignPro-G and PV Form will be used.
3. Only the optimum tilt (annual), direct south facing, 6-inch stand-off and direct-mount (including roof shingles) PV arrays with no shadowing (from vegetation, surrounding structures and row-to-row) will be covered.
4. PV system electrical design specifics, such as dc and ac conductor sizing and lengths, voltage drops across circuit breakers, disconnects, terminals etc will be included for the estimation of balance-of-system (BOS) power losses. Module mismatch losses will also be estimated.
5. Inverter operating characteristics, such as maximum power point tracking (MPPT) window, efficiency curve will be input in these simulations
6. PV system energy output will be predicted for at least five distinct climatic zones, such as (i) sunny, hot and dry (Phoenix, AZ), (ii) sunny, moderate and dry (Sacramento, CA), (iii) sunny, cold and dry (Denver/Golden, CO), (iv) sunny, hot and humid (Orlando, FL), and (v) partly cloudy, cold and humid (Boston, MA).

Task 2: Requirements for Validating PV System Performance Simulation Models

A number of PV performance simulation programs are available for predicting the output of a PV system. These programs range from very simple with few options for the user to select from to extremely sophisticated models with a daunting list of options and inputs. Some models are available free of charge; others can be purchased, while some are developed by system designers/integrators for their exclusive in-house use. Presumably, the developers of these models have performed some amount of testing and comparison to validate, at least to themselves, the results of their model. There is currently no standard method of evaluating the results from these models.

Under this task, Solar ABCs will develop a process for validating PV performance models. The process will likely include a set of system design characteristics, input weather data, and "actual" system performance. The design characteristics and weather data appropriate for the model under evaluation will be input to the model to provide a performance estimate and those results will be compared to the measured system performance. Several sets of design, weather, and performance data will be generated to address a variety of cell technologies, array configurations, and climatic conditions.

Comparisons will be made at the highest resolution offered by the simulation program (e.g., hourly) and at aggregated intervals (e.g., daily, monthly, or annual totals). Various measures of error will be provided and a set pass/fail criteria will be considered.

To accommodate a wide variety of modules, a very detailed set of data must be provided These required Validation Data fall into one the following three categories. Some examples of the type of data that might be need are shown under each.:

- **Measured Weather Data**

- Global horizontal irradiance, direct normal irradiance, plane-of-array irradiance , airmass, spectral distribution, ambient temperature, wind speed (at 10m height?) and wind direction, albedo, relative humidity, barometric pressure, water vapor, precipitation, aerosol, ozone, ultraviolet, date and time.

- **PV System Design Information**
  - Modules: cell technology, manufacturer, model, quantity, IEC 61215/61646 info, spectral response, temperature-irradiance characteristics from IEC 61853/Gap Analysis Topic 105, actual power rating, range and standard deviation of maximum power voltage and current for estimation of module mismatch power losses.
  - Array Electrical Design: modules/source circuit, source circuits/combiner box or subarray, combiner boxes or subarrays/array or inverter, number of inverters; wiring details: layout of combiner boxes, conductor sizes and lengths, BOS components (circuit breakers, disconnects, terminals) voltage drop and others.
  - Inverter: operational DC voltage range, DC maximum power point tracking window, operational AC voltage range, operational frequency range, start-up, shut-down, standby, nighttime losses.
  - Installation Configuration: system size, location, mounting type, installation details: fixed (tilt, azimuth) or tracking (one or two axes, axis orientation, axis tilt, tracking limits, back tracking), shadowing and soiling details.

- **Actual System Performance Data**
  - AC voltage, AC real and reactive power, DC voltage, DC current at source circuit level, subarray level, array level and system level, module temperatures, date and time.
  - Period: six-month minimum to include late winter and late summer, with spring preferred.

To accommodate the possible range of models that will be evaluated, an extensive and detailed Validation Data set will need to be defined. Actual input needs will be determined by the model under evaluation, and some standardized "rolling up" of parameters may be needed to ensure consistent use. It is anticipated that the Validation Data sets will start with actual systems that will be modified or further synthesized to ensure consistency and completeness.

Task 3: Submit Model Validation for Implementation as a Standard

This task will be conducted on the basis of the requirements developed and approaches decided in Task 2 beyond Year Two of the Solar ABCs Project. The national laboratories resources from NREL and Sandia, will be solicited for successful completion of this Task.

Standardization of Module Power Rating

Problem

PV modules are provided with a nameplate rating (in Watts at STC or Watts-Peak, Wp) and a tolerance band typically between ±3% and ±10%. Each module is flash tested at the end of the factory production line to establish its individual rating and, based on the tolerance band, assigned to a nameplate rating "bin" . Seeing such a tolerance band, one would expect a shipment of modules to, on average, equal the nameplate. However, an individual customer would have no recourse if all of the modules they received were at or just above the minimum rating defined by the lower bound of the manufacturer's tolerance. A major concern for PV consumers in the U. S. is the perception that the modules delivered to those consumers lacking any shipment-average requirements fall significantly below the nameplate, while modules delivered in Europe meet or exceed nameplate, on average [Atmaram, G., G. TamizhMani, G Ventre, "Need For Uniform Photovoltaic Module Performance Testing And Ratings", Proceedings of the 33rd IEEE PV Specialists Conference, May 2008].

This minimum rating is also used to define the starting point for allowable degradation for warranty claims, which means a particular module that

1. initially measures at the nameplate rating,
2. has a ±10% manufacturing tolerance (minimum power = 90% of nameplate), and
3. has a 20 year warranty specifying at least 80% of minimum power (72% of nameplate), can degrade at a rate of more than 1.63% per year (constant rate) and still be within the allowable warranty limits. Basing the warranty on the minimum power, in this case, allows nearly 50% higher degradation rate than if the warranty were based on nameplate (which would allow a 1.12%/yr degradation rate).

A third issue related to nameplate rating is that all PV modules are subject to an initial light-induced degradation (LID). For thin-film products, LID can be as much as 15-20% of initial power over the first 6-12 months of exposure. Crystalline products are also susceptible to LID ["A call for quality", Photon International, March 2008], though at typical levels of 1-4% and occurring over the first few hours of exposure to sunlight. While LID is almost universally reflected in thin-film module nameplate ratings well below the initial factor flash test results, crystalline products rarely if at all account for this known loss in their ratings. Module nameplate should fully account for LID in all technologies

Finally, the factory flash tests are subject to measurement uncertainties that can be as low as 2% or 3% in a well calibrated, well maintained system or as high as 10% if proper care is not taken.

Solution

Solar ABCs will take a multi-pronged approach to develop module power rating standards addressing each of these issues and implement them in the US market.

Task 1: Develop Proper Module Characterization Techniques

IEC Technical Committee 82, Working Group 2 is working on a Power and Energy rating standard (IEC 61835) for flat plate PV modules. The draft of Part 1 on Power Rating is now under review by National Committees, including the US TAG. Part 2 on measurement techniques should be circulated for review within 3 months. Part 3 on the methodology of energy calculation should be circulated for review by the end of 2008. This set of documents will form the basis of a power and energy rating. Solar ABCs will follow the progress of these documents and do what it can to facilitate the U. S. review and vote on them. In addition, ASU and FSEC will validate the procedures in IEC 61853 by performing the test protocol on a representative set of module types.

Task 2: Develop Standardized Module Rating and Reporting Requirements

The European community has established EN50380 entitled "Datasheet and nameplate information for photovoltaic modules". This document details the information that must be supplied with a PV module. This document requires the availability of module data at STC, NOCT and low irradiance as well as temperature coefficients. Upper and lower tolerances for maximum power must be provided. (The customer is then free to specify an acceptable tolerance for this.) All measurements should be after light induced degradation.

A U. S. document similar to EN50380 would provide a standard for module performance data. Customers could specify this document as part of the requirement for procurement. Therefore we propose the development of a U.S. Standard under IEEE SCC21 on "Datasheet and nameplate information for photovoltaic modules". One representative of Solar ABCs will chair this multi-year effort.

Task 3: Implementing Module Rating Scheme

PowerMark Corporation has established a procedure for third-party certification of PV module performance. This system has the following criteria:

1) Testing for the module power ratings should be done by an accredited, independent test laboratory.

2) Testing should be done on random sampling of modules from the marketplace (or production line).

3) The module nameplate rating tolerance should be based on the module nameplate power rating in accordance with the proposed U. S. standard, similar to the European standard EN 50380.

4) The module nameplate rating should account for LID.

5) The module nameplate rating should specify the maximum power degradation over module lifetime (for 20 or more years).

6) There should be some relatively simple (compared to the original testing) ongoing compliance check on the module nameplate rating on a periodic basis.

Under this task, the results of Tasks 1 and 2 would be incorporated into a Module Rating Scheme and implemented by PowerMark. An industry group consisting of module manufacturers, system integrators, private and public testing lab, NREL and Sandia will be actively involved to examine and review the scheme and promote its use by major funding institutions such as the California Solar Initiative and other state and utility-sponsored PV incentive programs.

Accelerated life testing for safety, reliability and durability of modules and the components used in modules

Problem

Crystalline silicon (c-Si) and thin-film (TF) photovoltaic modules are typically sold with 20-25 and 10-20 year warranty claims, respectively. However, there is, generally, no objective evidence with accelerated life testing to substantiate these warranty claims. In the absence of a publicly available accelerated life testing protocol or standard, the industry and consumers heavily depend on the qualification testing for the reliability/lifetime/warranty projection of the PV modules. Unfortunately, the qualification testing cannot be realistically considered as the reliability/lifetime testing.

The qualification testing is an excellent tool to identify major design issues and it may be considered as the preliminary/baseline requirement for the lifetime/reliability testing. As shown in Figure 1, the qualification testing does identify major/catastrophic infant mortality issues related to the module design [G. TamizhMani et al "Failure Analysis of Design Qualification Testing: 2007 vs. 2005", Proceedings of the 33rd IEEE PV Specialists Conference, May 2008] and the initial part of normal/useful life of PV modules in the field. In order to predict the lifetime of PV modules, the accelerated testing needs to be modified and extended much beyond the current qualification testing requirements. For example, a few manufacturers conduct the damp heat testing at 85°C/85%RH for 4,000 hours instead of 1,000 hours as warranted by the qualification testing standards. Therefore, it becomes important to develop one or more transfer functions for the lifetime prediction from accelerated testing; as expected, these transfer functions will be dependent on various influencing parameters such technology type, electrical configuration of the system and the weather conditions of the site. This work would initiate addressing the service life predictability, economics and consumer confidence.

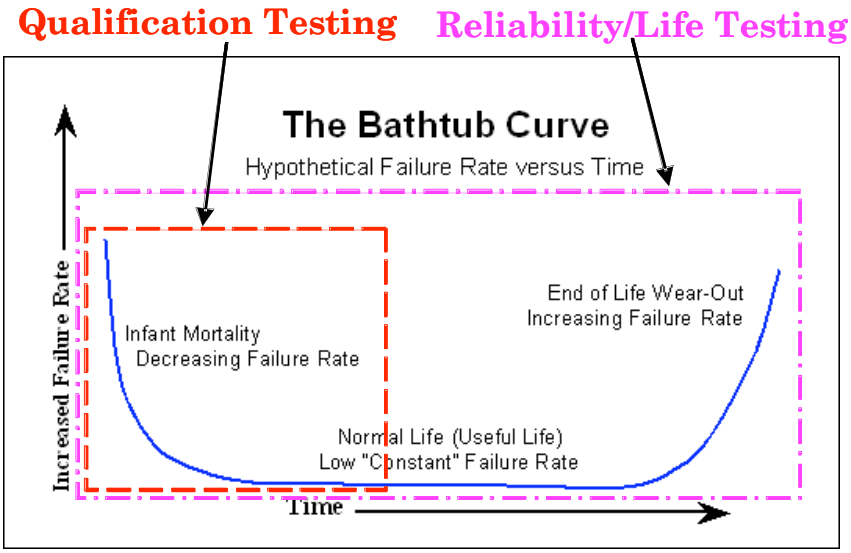


Figure 1: Bathtub curve for qualification testing and life testing

Proposed Solution

Establishing a correlation between time-to-failure in accelerated testing and time-to-failure in the field is a huge, multi-year undertaking, and it cannot be accomplished in a one-year study by Solar ABCs. This undertaking involves establishing a transfer function for each and every critical failure mechanism, e.g. corrosion and delamination in thin-film modules, and corrosion and solder bonds in c-Si modules. The eventual goal of this undertaking is two fold: (i) develop a standardized test protocol or a standard for the accelerated life testing of PV modules; and (ii) create a central clearinghouse (blinded database) on accelerated testing and failure data with a strong collaboration between the manufacturers, test labs, DOE, NREL, Sandia, and incentive providers (for example, energy commissions of the individual states) with privacy maintained on data sources. An approach will be taken in this one-year study period so that the above two goals could be achieved in 2-3 years timeframe. In this proposed one-year study, a detailed literature search will be carried and a draft test protocol will be developed as presented below.

Tasks

Task 1: Literature Search and Review: A large number of articles available in the public literature will be collected and reviewed to identify the common and major failure modes and mechanisms. A particular attention will be paid for the modules which underwent qualification testing and exposed in the field over 10 years. The sources for the literature collection would include:

- Long-term incentive providers including energy commissions of various states
- Utility companies including SMUD in California, APS and SRP in Arizona etc.
- Test laboratories including NREL, Sandia, FSEC, NMSU and ASU
- Proceedings of the reliability workshops organized by Sandia in 1990s
- IEEE-PVSC proceedings
- European Photovoltaic Conference proceedings
- Journals including Progress in Photovoltaics
- Conference tutorials organized in conjunction with IEEE-PVSC, and the SEMI and European conferences
- Models developed in the electronic industry including the Arrhenius models
- A systematic discussion with established module manufacturers under a strict confidentiality agreement

Task 2: Draft Protocol Development: At the end of this one-year study, a draft protocol will be developed which could serve as the basis for the development of a "Standard for Accelerated Life Testing or Recommended Procedure for Accelerated Life Testing" This comprehensive protocol will identify potential procedures to identify the failure modes and mechanisms. Since ASU-PTL is already an established facility for accelerated testing, PTL will attempt to collect a few of the old modules which had been type-tested for the qualification certification. These old modules will be subjected to the qualification testing or to the modified qualification testing for a correlation study. In addition to developing procedures, this study would develop preliminary transfer functions to correlate the accelerated life testing with actual field life.

Tasks

- Conduct an extensive literature search and review to identify various accelerated procedures, and failure modes and mechanisms
- Attempt to supply of a few field-stressed modules of various technology types and system electrical configurations
- Constantly interact and consult with NREL and Sandia to gain access to their database and literature
- Develop a draft protocol to serve as the basis for a future standard or recommended procedure / best practice
- Present the process in the "Solar Certification Forums" organized by IREC and the industry.

Standards to Certify the Accuracy of Inverter Meters

Problem

Solar photovoltaic power systems are most often being installed under net metering tariffs, which combine generated and consumed energy into a single "net" energy value. This simplifies the interconnection tariff and provides an economic incentive for consumers to install PV energy generation systems by valuing the generated energy at retail rates. However, other incentive programs are focusing on measuring the generation separate from the load in order to reward actions that improve total generation separately from actions that reduce load. For example, renewable energy credits are a marketable tender as long as they can be traced to energy production of an appropriate type of renewable energy source. Thus, in addition to the "net" revenue meter, a dedicated "production" meter is needed.

The challenge for residential-scale applications (less than 10kW) is that the cost of a separate energy production meter (~$90 for meter plus ~$40 for socket) is significant when compared to the profit margin available to the installer. Since these PV systems all include inverters that already measure power output in the course of performing their function, modifying these inverters to calculate the energy measurement is relatively simple, and in many cases manufacturers already offer energy generation measurement features. However, these energy measurements have been optimized for cost while still supporting acceptable energy conversion performance, and typically do not achieve the same level of measurement accuracy that a standard utility energy meter does (2%). Nevertheless, REC marketers and incentive program managers have indicated that there would be value in having available measurements certified at a 5% accuracy level for these purposes.

Standard utility revenue meters conform to standards such as ANSI C12.1, which defines tests to confirm that accuracy is maintained under a range of expected operating conditions (electrical and environmental). The California Public Utilities Commission has undertaken an effort to define a set of requirements that inverter-integrated energy meters will have to meet in order for recorded measurements from these sources to be acceptable for use in the Performance-Based Incentive program. While this scope is limited to a specific program in California, the goal of defining a standard set of requirements for inverter-integrated meters will be useful in any context where energy generated by grid-connected inverter-based power sources needs to be accounted for.

Proposed Solution

Create a standard set of requirements for integrated meters in inverter-based power generation systems. The proposed requirements defined by the CPUC will need to be reformulated in appropriate language to serve as a standard, and be guided through the process of review, integration of comments, and be voted on by an appropriate standards-making organization. Two distinct issues will need to be addressed: technical differences from existing standards arising from the use of a 5% accuracy requirement, and testing issues arising from having the meter integral with the inverter.

The scope of the proposed standard would be inverter-integrated metering. The requirements proposed by the CPUC have already identified that some requirements described by ANSI C12.1 Standard for Electricity Metering cannot be directly applied to inverter-integrated meters, but that in most cases similar requirements are already applied to inverters. Adding the integrated metering test requirements to an inverter standard or group of standards would be a logical next step. Both the IEEE Standards Coordinating Committee 21 (SCC21) and IEC Technical Committee 82 Working Group 6 (TC82 WG6) are possible venues for such a standard-making activity.

Tasks

1) Solicit input from the PUC and REC providers regarding their requirements for accuracy and inverter integration.
2) Assemble a Joint Committee of manufacturers, utilities, and other interested parties for review of the proposed standard language.
3) Submit proposed language to IEEE SCC21 or IEC TC82 for consideration as a standard.

Roof-top PV Module-specific Fire Research, Testing and Ratings Systems

Related to: Developing or revising a Standard

What is the major concern that this topic addresses?
The fire fighting commuity has concerns that roof-top PV modules may degrade the fire class ratings/fire resistance of roofing materials and promote unsafe conditions.

Why is this important and to what stakeholder groups?
Unnecessarily restrictive regulations may impeded the California solar market.

Who will benefit from remedying the concerns associated with this topic?
PV module manufacturers, installers, consumers, PV industry in general

What are the impacts of addressing this topic and for whom will these be favorable? Unfavorable?
Unfavorable – PV mfrs and supply chain could have increases in manufacturing costs if products have to be redesigned to meet increased fire rating requirements
Favorable – Industry will have scientific knowledge upon which to base requirements, legislation, acceptance, and move forward with assured safety.

Who else is working on this topic?
BIPV mfrs, UL proposed Solar ABCs fire testing project, other NRTLs and fire labs could possibly be working on this

Recommended Action to be taken by SOLAR ABCs:
1) Study to identify other entities working on this issue
2) Support UL's proposed Solar ABCs fire testing project (assuming it's good)
3) Deliver a white paper

National Fire Safety Guidelines for Roof-top PV Systems

Related to: Developing a Model Policy

What is the major concern that this topic addresses?
Firefighter safety, building fire safety, installation procedures and permit requirements

Why is this important and to what stakeholder groups?
It could streamline process, reduce costs and answer concerns of fire marshals; Stakeholders are 1) PV industry; 2) Fire Marshals; 3) Building officials; 4) Other stakeholders like insurers, builders, utilities, etc.

Who will benefit from remedying the concerns associated with this topic?
Same stakeholder groups

What are the impacts of addressing this topic and for whom will these be favorable? Unfavorable?
Favorable – For firefighters, it will streamline guidelines; for building officials, it will streamline permitting processes;
Unfavorable –it will now impose new guidelines/restrictions on fire class rating of PV products and requirements restricting PV from areas of the roof for access and ventilation.

Who else is working on this topic?
California State Fire Marshall and working group

Recommended Action to be taken by SOLAR ABCs:

- Draft a guidebook to the California State Fire Marshal Guidelines for Solar Photovoltaic Installations so that key stakeholders in other state can understand the context of the guidelines and understand how best to implement information from the guidelines. Given the wide variety of fire protection techniques, the application of the guidelines will vary significantly.
- Convene a group of fire officials and PV industry representatives to address testing needs of fire officials to understand various hazards when fighting fires on structures with PV systems (Brooks).

Revising Building Codes to Address PV Specifically

Problem:

The PV industry currently relies on the various interpretations of building codes by licensed structural engineers to design PV mounting systems. Alternatively, custom testing methods may be used and approved by a structural engineer and may include wind tunnel testing or computer simulations. This has resulted in a multitude of code interpretations, yielding different answers to the same design questions, as well as faulty test data being inadvertently applied to PV mounting systems.

The American Society of Civil Engineers (ASCE) Minimum Design Loads for Buildings and Other Structures (ASCE 7) is the most comprehensive wind design standard in the U.S. Other building codes, such as the International Building Code (IBC) contain wind design requirements, but are less comprehensive, especially for design problems with atypical building geometry, as is the case with roof-mounted PV systems. Fortunately, the IBC and other building codes explicitly permit the use of the ASCE code for the design of buildings and structures.

A recommended approach for the structural design of roof-mounted PV systems, based on the ASCE standard 7-05 has been developed under the Solar ABCs project. Examples are provided to demonstrate a step-by-step procedure for calculating wind loads. The approach is applicable to PV modules mounted on rooftops under 60 feet, when oriented parallel to the roof surface. An approach for PV modules oriented at an angle to the roof surface presents a more complex scenario and requires further research and testing.

The procedure for determining wind loads on buildings and structures is described in Chapter 6 of the ASCE standard. A thorough review of the code was conducted under the Solar ABCS project by a team of experts in the areas of PV system design as well as aerodynamics, wind tunnel testing, and the ASCE standard. The team was able to conclude that there is no prescribed method in the standard that specifically addresses the specific geometry of roof-mounted PV systems and design professionals are left with little or no guidance.

The problem of not having accurate internal pressure coefficients for common PV geometries is a key weakness in applying the standard to roof-mounted PV systems. However, making a conservative assumption, the team is confident that the wind loads on a roof-mounted PV system parallel to the roof can be estimated with the Section 6.5.12.2 of the ASCE standard.

Although some Figures in ASCE-7 have geometries that appear to be similar to tilted PV modules, is not recommended to apply this section to modules oriented at a tilt relative to the roof surface. None of the referenced Figures adequately address the geometry tilted PV, which is inherently non-aerodynamic, mounted on top of a building.

Proposed Solution

Additional work is required to understand the actual forces on roof mounted PV arrays. Without this basic information, the industry is left exposed to significant liability for structural failures of modules and mounting systems. Or, the consumers are potentially paying for site-specific engineering fees, conservative calculation errors, additional hardware expense, and extra labor costs. Wind tunnel testing is required to collect empirical data that will establish the relationship of the wind forces on the PV arrays. This information can be used to calibrate models that will allow designers to more effectively assess the loads applied to the modules, mounting structure, and the building.

The project team for the Solar ABCs year 2 wind loading on PV arrays task will include existing members from FSEC and BEW. Additionally, researchers from the Florida International University International Hurricane Research Center will provide the team with a means to evaluate wind loads at full and partial scale. Industry partners will also be included to provide products and possible leverage funding to assist with the development of the work.

Tasks:

Task 1
Wind Tunnel Testing for Roof Parallel Mounted PV Modules and Arrays
Scope
Wind tunnel testing will be conducted to determine the flow field and wind induces forces on PV modules and arrays mounted parallel to the slope of the roof surface. Data obtained from this testing will be used to calibrate numeric models and assess various array types and geometries.

Task 2
Recommended Additions or Changes to the Code
Scope
The empirical data and calibrated models developed under Task 1 will be used to directly address the wind forces on roof parallel PV modules and arrays. Recommendations will be made for changes or additions to the applicable codes based on the findings of the research. Reports and professional papers will be published.

Task 3
Guidance to Design Professionals for Roof Non-Parallel Mounted PV Modules
Scope
Documentation or publications will be made to offer recommended practices or calculation methods for applying the existing codes to cases where the PV modules or arrays can not be mounted parallel to the roof surface. The documents will offer sample calculations and suggestions for designing a code compliant project. This information will serve to fill a void that currently exists for designers and code officials.

Rate Impact of Net Metering

Related to:

- Developing a Best Practice
- Developing a Model Policy

What is the major concern that this topic addresses?

Penetration levels for net metering are set low (< 2.5% in CA and far less in most states), creating a barrier to deployment. By determining the rate impact and the non-monetary impacts at different penetration levels, a reasonable argument for higher penetration levels can be developed with negligible impact on utility profits. This determination must include impact of TOU rates and demand charges.

Rate impacts include the effects of reduced daytime energy generation, reduced T&D capital costs and eliminated line losses. Non-monetary items requiring valuation include the effect on carbon emissions and health impacts.

Why is this important and to what stakeholder groups?

Need the study to justify increased penetration levels for state net metering programs and support full net metering.

Who will benefit from remedying the concerns associated with this topic?

- Users and industry (manufacturers, installers, etc).
- Utilities through experience with interconnection of PV systems, which may be part of utility Integrated Resource Planning.

What are the impacts of addressing this topic and for whom will these be favorable? Unfavorable?

All favorable:

- Users – need fixed cost/benefit analysis that includes benefits of net metering
- Industry (manufacturers and installers) – want to sell more product and services
- Investors and lenders – want return and certainty
- Utility Commissions – concerned about fairness to parties / cost allocation
- Utilities – concerned about lost revenue, will benefit from hard data

Who else is working on this topic?

Studies conducted in California in the 1990s addressed net metering impacts on rates for low-level penetration (0.1%).

Recommended Action to be taken by SOLAR ABCs:

Perform the study discussed here.

Review and Recommend Updates to FERC Interconnection Screens

Related to:

- Developing a Best Practice
- Developing a Model Policy

What is the major concern that this topic addresses?
Several screens for fast track interconnection in section 2.2.1 of FERC's Small Generator Interconnection Procedure (SGIP) may be unnecessarily restrictive. Refining that list to simplify interconnection can reduce a barrier to solar energy installations. The SGIP screens are adopted in many state and utility interconnection standards, so the effect will extend far beyond FERC-jurisdictional lines.

Why is this important and to what stakeholder groups?
Important to update screens because it will simplify the interconnection process based on lessons learned after 40,000+ solar installations.

Who will benefit from remedying the concerns associated with this topic?
See below

What are the impacts of addressing this topic and for whom will these be favorable? Unfavorable?
All favorable:

- Users – simplified interconnection
- Industry – more sales
- Utilities –simplified process lowers costs
- Commissions – guidelines for state standards

Who else is working on this topic?
State public utility commissions and utilities consider the screens, but have little guidance for deviation from the screens. IEEE 1547.6 is working on spot network interconnection (one of the SGIP screens).

Recommended Action to be taken by SOLAR ABCs:
Perform the study discussed here and present to FERC. Work with related parties – IEEE, EEI, SEPA, NARUC.

PV Module Frame Grounding issues

Problem:

PV modules are typically installed on structures made of galvanized, painted, or stainless steel, or aluminum. These structures and any other electrically conductive components that could become energized by the PV array, and that could be accessible during routine servicing, must be bonded to a common earth ground. The National Electric Code (NEC) does not provide guidance on how metal parts should be bonded together to provide a reliable ground, and it is outside the scope of the Underwriters' Laboratories (UL) 1703 Standard for PV Modules. To our knowledge, there are no industry guides on how to design, install, and maintain a reliable electrical bond between metal parts in outdoor environments for 20+ years, leaving the installer with no option but to improvise solutions to this problem.

The result has been a surprisingly large number of fielded systems that (a) violated the module's UL listing by not complying with the installation manual's prescribed method of grounding the module frame; (b) did not result in an electrical connection between components, leaving module frames and/or the structure ungrounded, and/or (c) did create an electrical connection but the method was nevertheless improvised, with no testing, field validation, or certification to verify that the newly made connection would last for the design life of the system. Many of these fielded systems were inspected and approved by local building authorities, including an occasional system with no equipment ground to the structure or module frames whatsoever.

Current practices pose a life safety risk to maintenance and emergency response personnel, and complicate permitting and inspections due to the lack of clarity in what constitutes acceptable design practices. A serious injury or death resulting from an improperly grounded PV structure would be a tragedy, to say the least. Such an event would also carry ramifications for the entire industry, millions of dollars in liability (per death or injury), negative publicity for PV in general, and an increase in complications in obtaining permits.

Proposed Solution

A simple and practical "recipe" for equipment grounding of PV components be documented and made available to the public for the purpose of bringing clarity to this issue. Test methods will be developed for the purpose of evaluating the long-term reliability of the ground connections between metal parts in a PV array. The results will be applicable to any roof-or ground mounted PV array mounted on metal structures.

Tasks

The specific tasks are broken down as follows:

1. Define requirements: the technical requirements for a ground connection will be established. For example, array voltages and currents will be bracketed,

environmental conditions, and allowable electrical resistance between metal parts will be defined. This work will be done collaboratively between BEW and Tim Zgonena at UL.

2. Industry research: UL, utility engineers, and other industry experts will be surveyed for their experiences with this issue. Examples of successes and failures of similar applications will be studied. BEW will lead this effort.
3. Development of test methods: UL will lead the effort to identify test methods to evaluate long-term grounding solutions.

Appendix A

Suggested Gap Analysis Topics

ID#		Topic Recommendation	Suggested by
	STANDARDS		
	Needed Standards		
100		System Energy Performance Standards	ASTM E44.09 (Mani), Brian Sagar, Nanosolar, David Sweetman
101		Limitations in the *NEC* for determining the ampacity of conductors operating over 80 degress C.	
102		Standards on Manufacturing Safety Practices	Adam Detrick
103		Standards for Installation and Operation	Suzanne Borek
		Standardization of module characteristics:	
104		Both NOCT and other "normal operating temperature" test methods (i.e. in UL 1703) are performed in the open circuit condition. This significantly overestimates actual operating temperature, particularly as efficiency rises.	Adam Detrick
105		Standardization of module power ratings. Different mfg use different calibration labs, tolerances and policies on what the nameplate label is relative to actual module power. This is unfair to the end consumer who is forced to compare apples with oranges.	Adam Detrick
114		Test standards for non-PV solar technologies (apart from solar thermal). Safety, reliability and performance testing standards. Examples are dish sterling technology and solar thermal for absorption chillers.	Smita Gupta
111		User education standards, e.g. specify, use, test, measure, install, operate, maintain, integrate, connect, analyze, trouble-shoot, repair	David Sweetman
118		Accelerated testing. There is a lot of evidence that the current accelerated tests in IEC and UL don't replicate actual product lifetime expectancies (i.e. 25 year warranties). However, there is also the issue that certification time is already a heavy burden on the PV industry with respect to introducing new products and innovating. Perhaps this can get discussed in the context of UL being an industry bottle neck and the needed for expanded testing facility and acceptance of other NRTLs.	Adam Detrick
106		EVA Gel Content Test Method Validation (Need to make standard acceptable for PV manufacturer)	ASTM E44.09 (Mani)
107		Standard for PV and solar hot water specialty licenses (Is this in Solar ABCs scope?)	Stakeholder Meeting
108		Standards for variance control and reliability	David Sweetman
109		Standards for connections between equipment including hardware, firmware, software	David Sweetman
110		Standards for packing, labeling, shipping and recycling	David Sweetman
112		Standards for CPV Tests (covered in current study?)	Nick Chaset
113		Accelerated life-time testing of thin-film modules	
115		Manufacturing Waste Practices: Defined standards on manufacturing waste stream and subcontractor waste management (follow up from Washington Post article on Poly waste disposal)	Adam Detrick
117		Standards for shipping & recycling –consider voluntary industry product take-back standards as well.	Adam Detrick
178		UL should consider developing a generic method for testing clips so that manufacturers do not have to test every combination of clips with every module	
179		Clairfy the boundary between UL listing and local permitting requirements.	
	Standards/Certification Process		
119		Concern about new UL test facility and near monopoly of UL with testing	Steve Coonen, Open Energy
120		Significant Interpretations from UL are onerous and in some cases require UL lab testing. Not fair for other NRTLs who may interpretate differently. Changes of this magnitude should be run through STP and written into standard.	Adam Detrick
121		Overall certification process takes too long	Stakeholder Meeting
122		Standards Committees should meet more frequently - need to move quickly to support industry.	Stakeholder Meeting
123		Need cell qualification process (Why do component testing if you still have to do module testing?)	Stakeholder Meeting
	Certification/Qualification		
124		Need accelerated life testing for reliability and durability of modules and the components used in modules	Mani Tamizh-Mani
125		Need EnergyStar or EnergyStar-like certification or mark for module and/or system performance	Mani Tamizh-Mani
	Inverter Meters		
126		Standards to certify the accuracy of inverter meters. Needed to certify RECs and other applications. California is currently developing requirements. Need for CSI and maybe also for WREGIS REC trading.	Nicolas Chaset, Jim Baak

ID#		Topic Recommendation	Suggested by
127		Solar and the smart grid. Study the potential interplay between solar systems and Advanced Metering Infrastructures (subject of current study)	Nick Chaset
		CODES	
		Fire Safety Issues	
128		Fire Rating of PV Laminates - PV laminates must only meet Class C fire rating, which is not appropriate for roofs in the Western US. Comment: There is no evidence that anyone has brought forward which indicates that a lower fire class PV module negatively impacts a the fire rating of a higher classed roof. This is being addressed with UL and their white book statement.	Steve Coonen, Open Energy
129		National Model Fire Safety Guidelines (so California Guidelines do not become the national model)	
130		Testing for fire safety. Generic testing to answer questions firefighters have about interaction of PV and structural fires.	
131		Fire Codes vs Electrical Codes when dealing with batteries	
		Model Codes	
132		Model code should be developed for seismic areas (Some stakeholders thought this is not necessary)	Stakeholder Meeting
133		Model building codes regarding PV	DOE FOA
134		Model checklists for permit structural information	Jeff Wolfe, groSolar
		Building Codes (non-electrical)	
135		Coordinate with ICC-ES, the code writing authority for construction materials -- ICC-ES Code AC365 for BIPV roofing materials. Issues about snow loading and wind and seismic loads. Comment: Agree that there should be coordination with ICC in terms of writing model building codes but ICC-ES actually doesn't write code. They evaluate products.	Steve Coonen, Open Energy
		INTERCONNECTION AND NET METERING	
		Utility Rate Design/Net Metering	
136		Southern California Edison rate structure restrictve and negative for systems 1-5 MW	Solar Cities through A. Rosenthal
137		Residential Rate Structures and Solar (AB1x/flat or volumetric rates vs. TOU rates)	Nick Chaset
138		Assess the interaction between demand charges, demand rachets and net metering benefits	DOE FOA
139		Rate Impact of Net Metering	Stakeholder Meeting
140		Economics of net metering	DOE FOA
141		Study the economic difference between TOU net metering vs. flat-rate net metering, perhaps in a few select utilities' service territories	Rusty Haynes
142		Study the potential impact of feed-in tariffs or other similar production-based incentives on net metering	Rusty Haynes
143		Many coops do not allow net metering	David Sweetman
		Interconnection	
144		Usefulness of interconnection "screens" for quick approval of installations by local authorities, including BIPV	DOE FOA
145		Review of FERC and California Interconnection Screens (part of current study?)	
146		Review of costs associated with different interconnections standards (Ca's Rule 21, FERC Small Generator Interconnection Protocol). In CA, solar participating in CSI is subject to fast-track interconnection (no interconnection study), whereas through AB 1969 feed-in tariff, generators are subject to FERC SGIP, and therefore may have to bear the costs of interconnection studies and system upgrades.	Nick Chaset
147		Coops should, but do not have to, follow FERC rules	David Sweetman
148		Common SW & HW connection protocal from all inverter manufactures: Mechanical connection, refresh rates, minimum data transferred.	Adam Detrick
		GENERAL OR CROSS-CUTTING	
		Installation Guidance/Best Practices	
149		Provide guidance for sizing line-side interconnection conductors	Stakeholder Meeting
150		Information on large commercial system GEC sizing	Stakeholder Meeting
151		Best practices for solar thermal permits and inspections - wide variation in Minn. Some require 3 inspections (plumbing, mechanical, structural)	Stacey A. Miller, Minnesota Dept. of Commerce
152		Work with OSHA to get roof safety issues before PV stakeholders	Stakeholder Meeting
153		Mandating freeze protection for solar thermal	Nick Chaset
		BIPV Issues	

ID#		Topic Recommendation	Suggested by
154		Please address BIPV and building-applied modules versus rack-mounted modules as it applies to operating temperature, grounding, fire, etc.	Stakeholder Meeting
155		Develop research agenda to create data on which to base BIPV Standards related to NOCT test. Could be based on CEC specifications.	Chuck Whitaker, Smita Gupta
156		Add BIPV to list of issues for Product Safety Panel	Stakeholder Meeting
157		Parametric certification of BIPV	DOE FOA
158		Include in NEC: BIPV Issues	DOE FOA
	Grounding		
159		Grounding and bonding. Need to clarify requirements and avoid onerous requirements brought forth by UL significant interpretations.	Stakeholder Meeting
160		Need for training on proper design of grounding systems	Stakeholder Meeting
161		Grounding problems in harsh climates	
162		Grounding products – *proposal made to UL STP on this issue.*	Brian Wiley
	Performance Study		
163		Study the effects of airborne debris on PV modules or solar heating panels. Is this in regards to soiling or impact resistance/reliability?	
164		Recommendations for cleaning dust.	Stakeholder Meeting
165		Study the effects of shading on PV performance. In particular in the context of PV Incentive Programs where incentive calculators that include shading calculations.	Nick Chaset
166		Thermal interaction of BIPV with the building envelope and the effective heat transfer through the building element into the conditioned space	Smita Gupta
	Utility-Scale Solar Policies		
167		Large Generator Interconnection Policies and Procedures	Jim Baak
168		Streamlined Environmental Permitting	Jim Baak
169		Renewable Energy Transmission Access Policies & Procedures	Jim Baak
	Solar ABCs PROCESS/PRODUCTS		
170		Create a SAI central library - one web library for all data.	Stakeholder Meeting
171		Collect completed studies from other sources (CPUC, SEIA, etc.)	Stakeholder Meeting
172		Conduct web/phone seminar on key issues with experts	Stakeholder Meeting
173		How can states compare notes on what works and does not work?	Stakeholder Meeting
174		How to make standard and code processes more transparent?	
	UNSURE WHAT IS REQUEST		
175		Billing Systems	Stakeholder Meeting
176		Semi-conductor based disconnects: right now, a solid-state wwitch is not allowed as a system disconnect	Stakeholder Meeting
177		What tools, methods, knowledge, training is required to design, assemble, install functional systems – handbooks for designers, installers, users	David Sweetman
	REMOVED FROM GAP ANALYSIS CONSIDERATION		
		North American version of IEC 61730 (UL is working on this and it is near release)	
		These items no longer relevant with new California Guidelines?	
		Fire marshalls want quick release or hinged systems for tilting up modules on roofs	Stakeholder Meeting
		Fire issue: differentiate between HVDC, LVDC, AC Modules, systems with active shutdown	Stakeholder Meeting
		Smoke detector can be used to turn-off the inverters and PV system in case of fire	Stakeholder Meeting

Solar American Board for Codes and Standards

2010 Gap Analysis Final Report

July 12, 2010

Summary

The Solar America Board for Codes and Standards (Solar ABCs) 2010 Gap Analysis process was a formal review of the current state of the major codes and standards that bear on PV. The process identified major gaps that exist in the current work on codes and standards. These were then prioritized and developed into a strategic plan for the activities of the Solar ABCs for Year 4 and future years. Wherever possible, Solar ABCs will address the highest priority activities. Solar ABCs will also recommend others to address some of the important remaining activities.

From topics suggested by stakeholders, the Solar ABCs Steering Committee identified the following high priority topics to be addressed and placed them in this order.

Highest Priority Topic

- Follow-up Research on Flammability Issues

Second Highest Priority Topics

- Ground Fault Protection Improvements to Prevent Fires
- Standards for PV and Energy Storage
- Connection Issues of PV to the Smart Grid
- Guidelines for Utility Inspections of PV Systems

Third Highest Priority Topics

- Training for Installers and Fire Officials
- Develop operation and maintenance best practice guidelines including periodic safety-targeted inspection programs for Bypass-Diode Failures
- National Model Fire Guidelines
- Model Building Codes (ICC)
- Extend Expedited Permitting Guidelines to More Small Systems
- Develop Permit Guidelines for Large Systems
- Accuracy of Electro-Mechanical Meters
- Time-of-use Rate Structures

The following topics are recognized as being high priority, but the Solar ABCs will defer any work on these topics until further research or work at national labs is complete:

- Inverter Qualification Standard
- Standards for Power Conditioning and DC-DC- Converters
- Standards for High Penetration Solar

Solar ABCs recommends that, if possible, DOE fund the following task outside of the Solar ABCs as this task requires more resources than Solar ABCs currently has available.

- Web-based Code Official Training

The following topics are also recognized as high priority, but other organizations are working on the tasks already:

- Testing for Firefighter Safety (Underwriters Laboratories)
- Large Generator Interconnection Standards (Federal Energy Regulator Commission)

The Solar America Board for Codes and Standards (Solar ABCs) is a collaborative effort among experts to formally gather and prioritize input from the broad spectrum of solar photovoltaic stakeholders including policy makers, manufacturers, installers, and consumers resulting in coordinated recommendations to codes and standards making bodies for existing and new solar technologies. The U.S. Department of Energy funds Solar ABCs as part of its commitment to facilitate widespread adoption of safe, reliable, and cost-effective solar technologies. For more information, visit solarabcs.org

Introduction

The Solar America Board for Codes and Standards (Solar ABCs) Gap Analysis process reviewed the current state of the major codes and standards that bear on PV, identified major gaps that exist in the current work on codes and standards and prioritized these to become a strategic plan for the development of the Solar ABCs Annual Work Plan for future years. This document reports on the results of the 2010 gap analysis process. Solar ABCs also conducted a gap analysis process in 2008.

This report summarizes the method used to conduct the gap analysis, lists the potential topics identified, and establishes the priorities of the topics that will become the future work by Solar ABCs and others. In Years 4 and 5 of its contract with the U.S. Department of Energy, Solar ABCs will work on as many of the high priority topics as resources allow.

The Solar America Board for Codes and Standards (Solar ABCs) is a collaborative effort among experts to formally gather and prioritize input from the broad spectrum of solar photovoltaic stakeholders including policy makers, manufacturers, installers, and consumers resulting in coordinated recommendations to codes and standards making bodies for existing and new solar technologies. The U.S. Department of Energy funds Solar ABCs as part of its commitment to facilitate widespread adoption of safe, reliable, and cost-effective solar technologies. For more information, visit solarabcs.org

The Solar ABCs changes the practice of developing, implementing, and disseminating solar codes and standards in the following ways:

- By providing formal coordination in the planning and revision of separate, though interrelated, solar codes and standards
- By providing access for stakeholders to participate with members of standards making bodies in setting national priorities on technical issues
- By developing a centralized repository for collection and dissemination of documents, regulations, and technical materials related to solar codes and standards
- And by creating a centralized home for three key technical services: a) generating consensus 'best practices' materials and disseminating such materials to utilities, state and other regulating jurisdictions, b) answering code-related questions (technical or statutory in nature), c) providing feedback on important related issues to DOE and government agencies.

Method

A Gap Analysis was a major project for the Solar ABCs Steering Committee during its first year of operation. This second Gap Analysis was conducted two years after the first one. Stakeholders provided topics for consideration, the Advisory Committee and Steering Committee refined and prioritized the list of topics, and the Steering Committee developed the final list of high priority Gap Analysis topics.

Prior to soliciting stakeholder input for Gap Analysis, the first step was to develop a list of potential topics (or gaps) beginning with topics suggested during the first Gap Analysis process, but which had not been designated high priority. Included in this list were also high priority topics identified during the first process, but for which work has not yet begun. Finally, before soliciting new stakeholder input, a list was compiled that included all gaps suggested to the Solar ABCs Project Administrator since the completion of the first Gap Analysis.

Next, in the September 2009 Newsletter, Solar ABCs requested Gap Analysis input from all stakeholders. This was followed by the annual Solar ABCs Stakeholder meeting on October 29, 2009, during which the Project Administration briefed stakeholders on the Gap Analysis process and encouraged Stakeholders to submit potential topics. Stakeholders submitted proposed topics to the Project Administrator as a result of these requests.

The Project Administrator compiled the list and sent it to both the Steering Committee and the Advisory Committee for review and discussion. These discussions led to combining topics, adding topics, and reorganizing the way the topics were presented in order to facilitate better review and prioritization. The final list of proposed Gap Analysis topics is included in Appendix A.

The Advisory Committee and Steering Committee each reviewed and prioritized the Gap Analysis list. The Project Administrator compiled the results.

Finally, the Steering Committee conducted a day and a half meeting to prioritize the Gap Analysis topics. The Steering Committee reviewed the individual rankings, discussed, and approved a list of high priority Gap Analysis Topics. Then the Steering Committee developed detailed suggestions for the activities needed for each of the high priority topics.

The Gap Analysis Process was led by the Solar ABCs Steering Committee and managed by the Solar ABCs Project Administrator, Larry Sherwood. The Steering Committee includes one representative from the following organizations: Arizona State University, BEW Engineering, Brooks Engineering, Florida Solar Energy Center, Interstate Renewable Energy Council, National Renewable Energy Laboratory, New Mexico State University, North Carolina Solar Center, PowerMark, Sandia National Laboratories, Sunset Technology, Underwriter Laboratories, and U.S. Department of Energy plus a representative from the Solar ABCs Advisory Committee.

At the time of the Gap Analysis process, the Solar ABCs Advisory Committee included: Jim Baak, Vote Solar; Jon Bertolino, Sacramento Municipal Utility District; Suzanne Borek, New Jersey Department of Community Affairs; Alexander Bradley, Dupont; Nick Chaset, formerly with the California Public Utilities Commission; Marv Dargatz, Enphase Energy; Adam Detrick, SunPower Corp.; Mark Dougherty, Long Island Power Authority; Ryan Gaston, Dow Chemical Co.; Smita Gupta, Itron; Tom McCalmont, McCalmont Engineering; Colin Murchie, Solar City; Rhone Resch, Solar Energy Industries Association; Wilson Rickerson, Rickerson Energy Strategies; Mike Taylor, Solar Electric Power Association; Peter Varadi, Consultant; and Donald Warfield, BP Solar.

First and Second Tier

High Priority Gap Analysis Topics

FOLLOW-UP RESEARCH ON FLAMMABILITY ISSUES

RESEARCH OBJECTIVES

1. Provide specific tests and procedures that can be applied to PV installations and components to verify that they will have no impact on the fire rating of roof assemblies (with an emphasis on Class A rated roof assemblies).
2. Develop these tests and procedures into the form needed to serve as input for modifications to existing codes and standards such as UL1703, ICC, Model Codes, etc.

TEST PLAN

Following tests to be conducted at UL Fire Test Laboratory

1. Conduct Class A Spread of Flame tests on Class C PV module mounted over Class A roofs to see if the roof assembly will routinely pass Class A Spread of Flame test. Conduct tests for three different geometries, different module types, and over non-combustible roof products.
2. Verify the Burning Brands Tests previously conducted in order to define when mitigation is required. Conduct tests for different brand locations, different module types, and different roof types including non-combustible roof products. Investigate potential caloric load of debris accumulated under solar array to determine which size burning brand is appropriate for placement between the PV modules and the roof assembly.
3. Conduct Class A Spread of Flame tests for modules at tilts that are not parallel to the roof surface in order to determine how their performance compares with tests conducted on modules parallel to the roof surface.
4. Test several Spread of Flame mitigation techniques in order to develop mitigation recommendations. Document all test methods for preparation of recommendations that these be added to existing standard.
5. Develop and test Burning Brand mitigation techniques in order to provide mitigation recommendations. Tests to be developed after Item 2 tests define when mitigation is required. Develop language for required maintenance and cleaning between module and roof assembly.
6. Conduct Spread of Flame test on a large array to learn if tests conducted on single modules scale accurately to arrays with many modules.

New contractor to be identified for the following task:

7. Perform research to quantify the potential risk identified by the test results. A fire protection research engineer, economist, or actuarial insurance consultant will be hired to conduct this research.

DELIVERABLE: Solar ABCs Report

TIME: Year 4

GROUND FAULT PROTECTION IMPROVEMENTS

GAP: Ground faults have and will continue to be significant cause of failures and fire/fire risk. Arc-fault detection and mitigation measures underdevelopment are not mature for the PV industry and may not address many of the line to ground faults that are common in PV systems. Existing ground fault protection in inverters will not always detect faults in the grounded conductors, and subsequent faults can go uninterrupted (as in the case of the Bakersfield fire) and lead to damaging fires.

SOLUTION: Review and make recommendations on mitigating measures for reducing the risk of damaging ground-faults. These include targeted measures such as improvements to existing ground fault detection circuits in inverters, and/or additional over-current protection in the grounded circuits, to larger systemic solutions such as an emphasis on floating or high-impedance grounded systems as is commonly done in Europe and Asia. The analysis should include cost/benefit of different options as criteria, both for retrofitting existing systems and for new systems.

AUDIENCE: Code and standard makers, inverter manufacturers, industry designers and integrators.

WHO: Solar ABCs should take a lead role in developing recommendations and consensus, and can leverage external activities (such as UL-STP work in the protection area).

LEVEL OF EFFORT: Relatively low to develop problem statement and awareness, and help spearhead solutions with industry.

ENERGY STORAGE AND PV STANDARDS FOR GRID-TIED SYSTEMS

Energy storage required for diversion load, back-feed issues, peak shaving/matching, smoothing for high penetration, or networks with regard to grid-tied PV getting most out of the PV modules.

GAP: A methodology for optimizing power conditioning of PV hybrid systems exists for off-grid applications. An equivalent methodology does not exist for grid-connected PV applications. Currently being applied in an ad-hoc way.

SOLUTION:

- Gather existing data
  (Cost-benefit analysis, literature search and review, gather field data on existing demonstration projects - e.g. Lanai, Portland General Electric, San Ramon Facility)
- Write a White Paper on information gathered
  (Potential value to utilities, potential interactions with Smart Grid functions, recommendations for additional investment if needed)

AUDIENCE

Utilities, System Integrators, System designers, Public utility commissions
Eventually, funding bodies, EPRI

WHO

Solar ABCs
- Overseeing the project
- Progress reviews
- White paper

Labs
- NREL
- Sandia National Laboratories (SEGIS, Storage)
- PNNL
- Other test labs – ASU, DUIT

NIST Smart Grid group
Utilities (SMUD, Xcel, APS, AEP, OUC, PNM, etc.)
EPRI members
NYSERDA, CEC, other state energy offices, which may have funding available

LEVEL OF EFFORT

Solar ABCs:
- Overseeing, performing lit searches
- Writing white paper

Labs, utilities and manufacturers:
- Data sharing
- Writing/reviewing white paper
- Additional effort would likely be required based on results of white paper

STANDARDS FOR CONNECTION OF INTELLIGENT PV OR DG SYSTEMS TO UTILITY SMART GRIDS OR MICROGRIDS

GAP: Most inverter manufacturers may not aware of requirements to interface with smart grid and do not seem to be participating in development of interface, though ~5 contractors are required to be involved through SEGIS (solar energy grid integration systems)

SOLUTION: Identify current activities and inverter communication issues; get manufacturers involved

AUDIENCE: Inverter manufacturers, project developers, utilities

WHO: NC Solar Center

LEVEL OF EFFORT: limited

DELIVERABLE: Two-page description, webinar

WHEN: Year 4

DEVELOP OPERATIONS AND MAINTENANCE BEST PRACTICES GUIDELINE

GAP: There needs to be an larger overall system inspection procedure, for periodic evaluation of component damage that can result in later failures - including diodes, cabling, connections, etc. An example issue is undetected bypass-diode failures may be an endemic industry-wide sleeper problem and may lead to long term and failure/fire concerns. Need to determine the extent of problem and develop solutions.

SOLUTION: Outline and draft high-level and targeted inspection procedures. Leverage existing expertise in the area to create publicly available guidelines, which can be individually tailored for specific applications and market segments, e.g. residential systems with shading, vs. large scale commercial, event targeted inspections such as post lightning strike, e.g. apply inspection protocols and take note on each inspection item's value and resulting importance. Consider research on non-invasive, low labor methods of detecting bypass diode failures, e.g. high frequency or AC impedance measurements at the string or combiner box level. Also consider quality-based problems — better test standards for the diodes themselves. Consider an initial survey — targeted inspections to try and get some statistical understanding of the extent of the problem.

AUDIENCE: Installers, owners.

WHO: Solar ABCs led effort, possible leveraging of research and testing tasks.

DELIVERABLE: Report with Guideline recommendations.

EXTEND EXPEDITED PERMITTING GUIDELINES TO MORE SMALL SYSTEMS

GAP: Further expedite the process. There may be a gap for ac modules and other new technologies such as string inverter concepts.

SOLUTION: Update Expedited Permit Process report and then keep it up to date. Include minor expansions for new technologies.

AUDIENCE: Code officials, installers, designers

WHO: Brooks Engineering

LEVEL OF EFFORT: Small

DELIVERABLE: Revised Expedited Permit Report

WHEN: Year 4

INTERNATIONAL CODE COUNCIL (ICC) CODE DEVELOPMENT

Prioritized topic was Model Building Codes Regarding PV

(recommendation developed by Larry Sherwood)

GAP: Stakeholders are not participating in International Code Council (ICC) Code Development activities. Recently, ICC has considered code changes for the International Fire Code and the International Plumbing Code, which affect PV installations.

SOLUTION: Solar ABCs should facilitate a group of stakeholders to develop code change proposals and provide comments on proposed changes. The group could operate similar to the PV Industry Forum, which provides recommendations for changes to the National Electrical Code. Codes include the International Building Code, the International Fire Code, the International Plumbing Code and the new International Green Construction Code. Perhaps this group could also comment on the Uniform Solar Energy Code developed by IAPMO.

AUDIENCE: ICC, solar industry, code officials

LEVEL OF EFFORT: Moderate – need someone to coordinate the activity.

WHEN: On-going

ACCURACY OF ELECTRO-MECHANICAL METERS OPERATING IN THE REVERSE DIRECTION IS MUCH LOWER THAN AS DESIGNED FOR FORWARD OPERATION

GAP: A report from Measurement Canada indicates electro-mechanical meters operating in the reverse direction run slightly slow

SOLUTION: Review Canadian study and meter standards to identify if inaccuracy in reverse direction is possible and recommend next steps (not testing meters)

AUDIENCE: Utilities, utility commissions, standards bodies (NIST and ANSI)

WHO: NCSC, BEW, or FSEC, etc. (or NIST or ANSI)

DELIVERABLE: Report

EFFORT: Small effort

RATE STRUCTURES

GAP: No existing factual analysis of rate impact by utility

SOLUTION: Need analysis of impact on utilities of various rate structures, including flat, TOU and demand-metered. Need to address variations by utility of location, generation mix, etc.

AUDIENCE: Utility commissions, legislators

EFFORT: Huge if utility by utility, but helpful to start with a few

DELIVERABLE: Report

WHEN: Year 5

Appendix A

Suggested Gap Analysis Topics

(in pdf file)

STANDARDS	
Needed Standards	
	Standards for Installation and Operation
	Standards for CPV Tests (done?)
	Standards for connection of intelligent PV or DG systems to utility smart grids or microgrids. May require more than one standard.
	Limitations in the *NEC* for determining the ampacity of conductors operating over 80 degress C.
	Standards on Manufacturing Safety Practices
	Test standards for non-PV solar technologies (apart from solar thermal). Safety, reliability and performance testing standards. Examples are dish sterling technology and solar thermal for absorption chillers.
	User education standards, e.g. specify, use, test, measure, install, operate, maintain, integrate, connect, analyze, trouble-shoot, repair
	EVA Gel Content Test Method Validation (Need to make standard acceptable for PV manufacturer)
	Standards for connections between equipment including hardware, firmware, software
	Standards for packing, labeling, shipping and recycling
	Manufacturing Waste Practices: Defined standards on manufacturing waste stream and subcontractor waste management (follow up from Washington Post article on Poly waste disposal)
	Standards for shipping & recycling –consider voluntary industry product take-back standards as well.
	Clairfy the boundary between UL listing and local permitting requirements.
Standards/Certification Process	
	Need cell qualification process (Why do component testing if you still have to do module testing?)
	Concern about new UL test facility and near monopoly of UL with testing
	Significant Interpretations from UL are onerous and in some cases require UL lab testing. Not fair for other NRTLs who may interpretate differently. Changes of this magnitude should be run through STP and written into standard.
	Overall certification process takes too long
	Restructure the UL Standards writing process to allow it to better meet the needs of an industry where the technology is changing rapidly.
	Exact list of polymeric materials tests (as per UL 1703) for encapsulant, junction box, cable, connector and backsheet.
Certification/Qualification	
	Develop QA Guidelines for deterining lifetime testing
	Encourage adoption of Solar ABCs qualification policy
CODES	
Fire Safety Issues	
	Fire Codes vs Electrical Codes when dealing with batteries
	National Model Fire Safety Guidelines (so California Guidelines do not become the national model)
	Follow-up work to Fire Safety Research Project (recommendations, more research?)
	Fire Rating of PV Laminates
	BIPV and Fire Safety issues
	Testing for fire safety. Generic testing to answer questions firefighters have about interaction of PV and structural fires.
	Flammability Testing of Roofs and Rack-mounted PVs (follow-up to previous research)
	Test a large array rather than one module (what is the sensitivity of results to the size of the array?). One manufacturer for all modules in the array. Are the completed results with one module the same or different as a test with a large array.
	Vary the impingement location of the flame so the flame is at the top of the PV module.
	Test varying stand-off heights to determine at what threshold the roofs passed
	Characterize the exposure of the roof from a room of content fire over the roof eave.
	Test the performance of Class C PV on concrete tile roof (plus maybe metal roofing) on combustible decks (non-combustible roofing) (790 test) How does this construction differ with current test results?
	Test other typical commercial applications. Vary tilt of module relative to roof. Low slope
	What is correlation between Class A brand and debris accumulated under solar array in the field. Caloric load. (do literature search first)
	What is the extra potential fire risk from PV installations? Address field data.
	Research possible solutions (testing mitigation measures).
NEC	
	Gap between NEC 690 for PV and non-PV Concentrating Solar Power Systems
	Semi-conductor based disconnects: right now, a solid-state wwitch is not allowed as a system disconnect
	Smart grid connections realted to fire safety and the NEC
	Initiate discussions with NFPA concerning the lack of current technical expertise on Code Making Panels, which is significantly hampering the development of codes that address the requirements for the application of sophisticated electrical and electronic power conversion devices as well as circuits containing these devises.
	Investigate whether or not the dc overcurrent devices currently used in outdoor PV combiner boxes are or are not suitable for use in the PV combiner box environment.
Model Codes	
	Wind Load Testing, Analysis and Design Code Development
	Wind loading codes for ballasted rooftop systems
	Expedited permitting and/or best practices for systems which do not fall within the criteria of the current expedited permitting process

	Companion report to Expedited Permitting Report dealing with utility permitting/inspection best practices or recommendations.
	Web-based Code Official Training
	Model code should be developed for seismic areas (Some stakeholders thought this is not necessary)
Building Codes (non-electrical)	
	Model building codes regarding PV
	Coordinate with ICCon model building codes
	OSHA rules on PV set-backs on roofs
	Coordinate with ICC-ES, on code compliant testing standards
INTERCONNECTION AND NET METERING	
Utility Rate Design/Net Metering	
	Residential Rate Structures and Solar (AB1x/flat or volumetric rates vs. TOU rates)
Interconnection	
	Potential of AMI Data to Reduce Technical Issues Related to Interconnection
	Examination of NREL RSI Studies and guidance to states adopting interconnection procedures and net metering laws
	Ownership data from AMI Systems
	Standard for access to AMI data for Smart Grid interconnection priorities related to energy availability and energy useage
	Issue of large installations and high penetration on grid stability. Can beneficial voltage support requirements and anti-islanding provisions co-exist?
	Accuracy of electro-mechanical meters operating in the reverse direction is much lower than as designed for forward operation
	Review of costs associated with different interconnections standards (Ca's Rule 21, FERC Small Generator Interconnection Protocol). In CA, solar participating in CSI is subject to fast-track interconnection (no interconnection study), whereas through AB 1969 feed-in tariff, generators are subject to FERC SGIP, and therefore may have to bear the costs of interconnection studies and system upgrades.
	Common SW & HW connection protocal from all inverter manufactures: Mechanical connection, refresh rates, minimum data transferred.
GENERAL OR CROSS-CUTTING	
Installation Guidance/Best Practices	
	Provide guidance for sizing line-side interconnection conductors
	Best practices for solar thermal permits and inspections - wide variation in Minn. Some require 3 inspections (plumbing, mechanical, structural)
	Work with OSHA to get roof safety issues before PV stakeholders
	What tools, methods, knowledge, training is required to design, assemble, install functional systems – handbooks for designers, installers, users
BIPV Issues	
	Develop research agenda to create data on which to base BIPV Standards related to NOCT test. Could be based on CEC specifications.
	Add BIPV to list of issues for Product Safety Panel
	Parametric certification of BIPV
	Include in NEC: BIPV Issues
Performance Study	
	Study the effects of airborne debris on PV modules or solar heating panels. Is this in regards to soiling or impact resistance/reliability?
	Study the effects of shading on PV performance. In particular in the context of PV Incentive Programs where incentive calculators that include shading calculations.
	Thermal interaction of BIPV with the building envelope and the effective heat transfer through the building element into the conditioned space
Utility-Scale Solar Policies	
	Large Generator Interconnection Policies and Procedures
	Streamlined Environmental Permitting
	Renewable Energy Transmission Access Policies & Procedures
Solar ABCs PROCESS/PRODUCTS	
	Start Industrial Affiliates Program to fund some additive codes and standards work from industry.
	Conduct more discussions/presentations/webinars on reports
	Redesign web site – current website is confusing. Want to be able to find reports easily.
	Some "quick survey" work with the stakeholders involved in these reports might be a useful addition – no more than 5 questions – firefighters, utilities, city planning departments, code inspectors, etc.

Solar ABCs
High Priority Gap Topics
Revised July 2011

Highest Priority Topics
Ground Fault Protection Improvements to Prevent Fires
Maintenance and Inspection Guidebook
Universal PV Interface Standards
PV Connector Standard
White Paper on the Use of Modules with Embedded Electronics
TOV Overvoltage on Distribution System

Other Priority Topics
Develop Permit Guidelines for Large Systems
Guidelines for Utility Inspections
Bypass-Diode Failures/Safety-Targeted Periodic Inspection Programs
Standards for PV and Storage
Connection of PV to the Smart Grid
Structural and Snow Load Issues
Flicker Impact on Distribution System

DESCRIPTION OF TOPICS

Ground Fault Protection Improvements to Prevent Fires

Problem: Ground faults have and will continue to be significant cause of failures and fire/fire risk. Arc-fault detection and mitigation measures underdevelopment are not mature for the PV industry and may not address many of the line to ground faults that are common in PV systems. Existing ground fault protection in inverters will not always detect faults in the grounded conductors, and subsequent faults can go uninterrupted (as in the case of the Bakersfield fire) and lead to damaging fires.
Solution: Review and make recommendations on mitigating measures for reducing the risk of damaging ground-faults. These include targeted measures such as improvements to existing ground fault detection circuits in inverters, and/or additional over-current protection in the grounded circuits, to larger systemic solutions such as an emphasis on floating or high-impedance grounded systems as is commonly done in Europe and Asia. The analysis should include cost/benefit of different options as criteria, both for retrofitting existing systems and for new systems.
Resources: Solar ABCs should take a lead role in developing recommendations and consensus, and can leverage external activities (such as UL-STP work in the protection area).

Maintenance and Inspection Guidebook

Problem: Some solar installations are aging and some of the installers of these older systems are no longer in business. These systems need to be properly maintained to insure safe and efficient operation.

Solution: Publish a Solar ABCs Maintenance and Inspection Guidebook, which includes best practices for inspecting and maintaining systems. Inspection procedures would include both visual inspections as well as recommended tests.
Resources: Author to receive input from stakeholders and write guidebook.

Universal PV Interface Connectors
Problem: Universal PV Interface (UPVI) is the standard connection method and mechanical footprint for the attachment of power electronics (inverters, DC/DC converters, measurement circuits) or cable assemblies to the back of a module. Installers are increasingly making connections with products from different manufacturers. Since there are no standards for these connectors, there is concern about safety and reliability issues.
Solution: Build industry consensus on what standards are needed for universal PV connectors. Convene a small group (modules, jbox, NRTLs, Sandia, NREL) to develop proposal and then involve a larger group of stakeholders.

PV Connector Standard
Problem: These connectors are the ends of the "pigtails" that are attached permanently to existing technology modules. Installers are increasingly making connections with products from different manufacturers. Since there are no standards for these connectors, there is concern about safety and reliability issues.
Solution: Convene a group of stakeholders to agree on general principles for a connector standard. Goal is to have good connector reliability.
Resources: Need someone to facilitate the stakeholder process.

White Paper on Use of Modules with Embedded Electronics
Problem: The application of UL1703 and UL1741 for modules with embedded electronics results in conflicting issues.
Solution: Publish a Solar ABCs White Paper, which will give guidance to AHJs and installers on how to interpret the existing codes and standards and give guidance to NRTLs on how to label, mark, and rate such products.
Resources: Author to receive input from stakeholders and write white paper.

Bypass-Diode Failures/Safety-Targeted Periodic Inspection Programs
Problem: There needs to be an larger overall system inspection procedure, for periodic evaluation of component damage that can result in later failures - including diodes, cabling, connections, etc. An example issue is undetected bypass-diode failures may be an endemic industry-wide sleeper problem and may lead to long term and failure/fire concerns. Need to determine the extent of problem and develop solutions.
Solution: Report with Guideline recommendations. Outline and draft high-level and targeted inspection procedures. Leverage existing expertise in the area to create publicly available guidelines, which can be individually tailored for specific applications and market segments, e.g. residential systems with shading, vs. large scale commercial, event targeted inspections such as post lightning strike, e.g. apply inspection protocols and take note on each inspection item's value and resulting importance. Consider research on non-invasive, low labor methods of detecting bypass diode failures, e.g. high frequency or AC

impedance measurements at the string or combiner box level. Also consider quality-based problems — better test standards for the diodes themselves. Consider an initial survey — targeted inspections to try and get some statistical understanding of the extent of the problem.
See also Maintenance and Inspection Guidebook above.

Standards for PV and Storage
Problem: A methodology for optimizing power conditioning of PV hybrid systems exists for off-grid applications. An equivalent methodology does not exist for grid-connected PV applications. Currently being applied in an ad-hoc way.
Solution: White paper on existing data (Cost-benefit analysis, literature search and review, gather field data on existing demonstration projects - e.g. Lanai, Portland General Electric, San Ramon Facility)

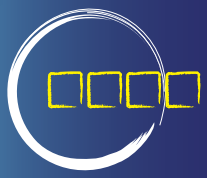
Connection of PV to the Smart Grid
Problem: The foundation of the future smart grid is being poured now, but the PV industry may be underrepresented at the planning table and in the field. A very vital location for the PV industry's voice to be heard is in the smart grid standards-making activities currently taking place. While in the US both the PV and the Smart Grid industries are rapidly growing they do not necessarily interact very much, yet.
Solution: The goal of the project is to make the PV industry more aware of current smart grid development activities, particularly standards development, and to highlight opportunities for active participation by the PV industry in these efforts. This Solar ABCs project will provide the PV industry both a written guide and two webinars outlining the current activities designing the future smart grid with a focus on standards-making activities that are pertinent to the integration of PV and other distributed generation systems in the grid.

Structural and Snow Load Issues
Problem: Current codes do not well handle structural issues. Solar ABCs has a current research project on wind load issues, but does not have any current activities relating to dead loads.
Solution: Coordinate with others working on this issue to develop recommendations for code changes related to structural issues.
Resources: Author to receive input from stakeholders and write guidebook.

Comparison of the Four Leading Small Generator Interconnection Procedures

Prepared by
Jason B. Keyes and Kevin T. Fox
Interstate Renewable Energy Council

Solar America Board for Codes and Standards
www.solarabcs.org



Solar American Board for Codes and Standards Report

Comparison of the Four Leading Small Generator Interconnection Procedures

Prepared by

Jason B. Keyes and Kevin T. Fox

Interstate Renewable Energy Council

October 2008

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Download a copy of the report:
www.solarabcs.org/interconnection

Executive Summary

Public interest in distributed generation, particularly solar energy systems, has fostered federal and state legislation calling for streamlined procedures for interconnection of generators to the electric grid. Existing procedures have proven inadequate in many cases, with high costs, lengthy timelines, bureaucracy, and uncertainty acting as formidable barriers to entry. In response to the continuing wave of legislation, utility regulators at the state and local levels are actively revising their interconnection procedures and will continue to do so in the future. This paper is intended to serve as a guide for those regulators.

This paper reviews four sets of interconnection procedures that regulators often consider when developing state and local procedures. As a framework for review, the paper uses the grading criteria developed by the Network for New Energy Choices (NNEC) and used in that organization's review of state interconnection procedures (*Freeing the Grid*, 2008).

The four interconnection procedures that are reviewed based on the NNEC criteria are:

1. The federal procedures, in two parts: the Small Generator Interconnection Procedure (SGIP) and the Small Generator Interconnection Agreement (SGIA) developed by the Federal Energy Regulatory Commission (FERC) in 2005 and refined in 2006.
2. California's Rule 21 (CA Rule 21), first approved in December 2000, modified slightly through utility tariff filings, and used for the interconnection of the majority of solar facilities and other distributed generation facilities in the United States.
3. The Mid-Atlantic Demand Resource Initiative procedures (MADRI Procedures developed in 2005 by the utility commissions of Delaware, New Jersey, Maryland, Pennsylvania, the District of Columbia, the PJM Interconnection (the regional transmission organization for the states just listed), and various federal agencies.
4. The Interstate Renewable Energy Council's Model Interconnection Standards and Procedures for Small Generator Facilities (IREC Procedures) finalized in late 2006.

The SGIP/SGIA and CA Rule 21 were developed through the efforts of utilities, regulators, industry representatives, consumer and environmental advocates, and other interested parties. The MADRI Procedures are the product of a regional effort in an area with minimal distributed generation, which tended to limit representation to utilities and regulators. The IREC Proceduresare an assemblage of best practices from the SGIP/SGIA, the MADRI Procedures, and various state procedures. The Interstate Renewable Energy Council (IREC) is a nonprofit organization that has actively participated in dozens of state rulemakings and helped NNEC develop the criteria in *Freeing the Grid* (2008). NNEC is a nonprofit organization primarily funded by a family trust without ties to the solar industry. Citations and links to the four procedures and *Freeing the Grid* (2008) are provided in the references section of this paper.

Background on the four procedures and the development of interconnection procedures generally is presented in the introduction and literature review sections. Review of the four procedures using the NNEC criteria is provided in the analysis section, along with a description of the relevance of each criterion. The analysis section is the most detailed portion of the paper, and one could skip directly to the conclusions and recommendations sections depending on one's level of interest. A table summarizing the scores for the four sets of procedures for each *Freeing the Grid* (2008) criterion is presented in the conclusions section.

Summary of Conclusions

The NNEC grading criteria in *Freeing the Grid* (2008) are all set at a score of zero for the SGIP/SGIA (the federal procedures), and state procedures receive positive or negative points for each of the criterion based on a comparison with the SGIP/SGIA. The SGIP/SGIA is given a grade of "C," and only twelve state procedures score higher. One of those is CA Rule 21, receiving a "B." As the NNEC looked to the IREC Procedures to determine what features should be awarded maximum criterion scores, it is not surprising that the IREC Procedures receive an "A." The MADRI Procedures receive a low C, which surpasses the procedures (or lack of procedures) in 35 states as of October 2008, according to *Freeing the Grid* (2008).

The procedures reviewed in this report have similar provisions on three key points that regulators should recognize as essential: one standard for all technologies, applicability to systems up to at least 10 MW, and use of national engineering standards. On a fourth important point, all of the procedures except the SGIP/SGIA do not require insurance for most systems, and the authors of this report recommend that insurance not be required. As well, all but CA Rule 21 use the basic format of the SGIP/SGIA, and the authors consider this uniformity a useful benefit because industry and utilities are already familiar with the federal procedures.

There are two key differentiators between the IREC Procedures and the other three: whether an external disconnect switch is required and size limitations for interconnection to spot networks and area networks. NNEC and IREC believe that both issues are viewed with excessive caution by utilities while the other procedures reviewed here err on the side of caution. A third differentiator is the dispute-resolution process, with the IREC Procedures settling on use of a technical master to make binding decisions rather than relying on costly arbitration and litigation, which are impractical solutions for minor disputes. And finally, the IREC Procedures and CA Rule 21 adopt simplified processes to interconnect systems that cannot export power to the electric grid while the other procedures do not.

Summary of Recommendations

The authors are attorneys who represent IREC in interconnection and net metering rulemakings before state utility commissions. In 2007-2008, this representation entailed travel to a dozen states to participate in workshops and formal rulemakings. As well, the authors participated in the refinement of *Freeing the Grid* for 2008. Obviously, this biases the authors in favor of the NNEC grading methodology and the IREC Procedures. Nevertheless, the authors believe that *Freeing the Grid* (2008) provides a fair and objective set of criteria for assessing state interconnection procedures in light of the goal of facilitating the interconnection of distributed generation. A concerted attempt has been made to present differing viewpoints as fairly as possible and to critique the IREC Procedures.

The authors' primary recommendation is that utility regulators use familiar procedures as a starting point for the development of their own rules. Any of the four procedures discussed here can serve as a suitable starting point, though the authors favor the IREC Procedures. As regulators develop rules starting from selected procedures, each NNEC criterion should be considered, and regulators should either adjust the procedures they are using to maximize the NNEC score or articulate why they are choosing an alternative approach. Especially with respect to criterion related to cost causation, regulators should consider whether there are offsetting benefits that justify applying a particular cost to ratepayers generally. And finally, beyond the NNEC criteria, the authors recommend that regulators strive to achieve the somewhat conflicting goals of simplicity and comprehensiveness. Distributed generation is far more likely to be deployed if developers and utility customers can easily discern what the costs of interconnection are and how long the approval process will take.

Author Biographies

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Jason Keyes co-founded Keyes & Fox, LLP in 2008. Primarily, he represents the Interstate Renewable Energy Council in state utility commission rulemakings related to net metering and interconnection of renewable energy systems. His background includes regulatory work related to renewable energy project development and finance, eight years of government contract management for a solar energy start-up, and integrated resource planning for a major electric utility. Jason holds a JD from Seattle University School of Law, an M.A. in Economics from the University of Washington and a B.A. from Dartmouth College.

Kevin Fox

Kevin Fox co-founded Keyes & Fox, LLP with Jason Keyes. Kevin's background includes regulatory work for electric, natural gas and water utilities as well as regulatory and project finance work for renewable energy project developers. He also completed research fellowships with two United States Department of Energy laboratories and worked in the Demand Analysis Division of the California Energy Commission. Like Jason, Kevin's current practice focuses on representation of the Interstate Renewable Energy Council in rulemakings related to net metering and interconnection of renewable energy systems. Kevin holds a J.D. from the University of California at Berkeley and a B.S. in Energy Policy Analysis and Planning from the University of California at Davis.

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Solar America Board for Codes and Standards

The Solar America Board for Codes and Standards (Solar ABCs) is a collaborative effort among experts to formally gather and prioritize input from the broad spectrum of solar photovoltaic stakeholders including policy makers, manufacturers, installers, and consumers resulting in coordinated recommendations to codes and standards making bodies for existing and new solar technologies. The U.S. Department of Energy funds Solar ABCs as part of its commitment to facilitate wide-spread adoption of safe, reliable, and cost-effective solar technologies.

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www.solarabcs.org

Acknowledgements

This material is based upon work supported by the Department of Energy under Award Number DE-FC36-07GO17034.

Table of Contents

Disclaimer ii

Executive Summary iii

Summary of Conclusions iv

Summary of Recommendations iv

Author Biographies v

Solar America Board for Codes and Standards v

Acknowledgements v

Introduction 1

A brief history of interconnection procedures 1

NNEC's *Freeing the Grid* 3

Overview of the four interconnection procedures 5

FERC's small generator interconnection procedures and agreement 6

California's Rule 21 7

MADRI small generator interconnection procedures 9

IREC's interconnection procedures 10

Literature review 11

Analysis 12

1. Eligible Technologies 12
2. System Capacity 12
3. Breakpoints 12
4. Timelines 14
5. Interconnection Charges 16
6. Engineering Charges 17
7. External Disconnect Switch 18
8. Certification 19
9. Technical Screens 19
10. Spot Network Interconnection 20
11. Area Network Interconnection 21
12. Standard Form Agreement 22
13. Insurance Requirements 22
14. Dispute Resolution 23
15. Rule Coverage 23
16. Miscellaneous 24

Conclusions 24

NNEC grading of the SGIP 24

NNEC grading of CA Rule 21 25

NNEC grading of the MADRI Procedures 25

NNEC Grading of the IREC Procedures 26

Recommendations 28

References 29

Procedures reviewed in this paper 29

Other procedures and standards 29

Reports and other publications 29

Legislation, statutes, regulations and administrative issuances 30

Introduction

The focus of this paper is on the practical matter of how four of the most well used interconnection procedures are graded under the Network for New Energy Choices (NNEC) grading criteria, with the intent of helping regulators and utilities select useful starting points for the development of their own rules. Provided in this section are introductions to the four procedures that are analyzed in depth in the analysis section. To preface that discussion, this introduction provides a description of the sixteen NNEC grading criteria used in NNEC's publication, *Freeing the Grid* (2008), which is the basis of the analysis in this paper.

It is helpful to be familiar with the history of interconnection procedures, prior to the review of the NNEC grading criteria and the four procedures; therefore, this introduction begins on that note.

A brief history of interconnection procedures

Prior to 2003, few states had comprehensive rules for interconnection of distributed generation, which can be described roughly as anything from a hundred-watt solar panel up to a 20-megawatt combustion turbine. Rules for interconnection of larger, traditional utility-scale generators were applied to distributed generation, with varying degrees of recognition that these smaller systems were less complex. The existing rules were based on interconnection to high-voltage transmission lines, where generation was traditionally located, though small distributed generators more often tie into medium-voltage utility distribution lines. For the most part, utilities had broad discretion to study the impact of an interconnection at the customer's expense. In addition, because few small generator interconnections were proposed, a lack of utility experience with these interconnections meant that the cost of the review process could overwhelm the cost of the system itself, particularly for modest residential-scale systems. Following on interconnection rule development in Texas and New York, California was among the first states to attempt a comprehensive rule for interconnection of distributed generation with the development of CA Rule 21 in the year 2000, but few other states followed that lead.

Three critical events in 2003 foreshadowed the widespread adoption of interconnection procedures for distributed generation that exists today. First, the Institute of Electrical and Electronic Engineers (IEEE) finalized IEEE 1547—the Standard for Interconnecting Distributed Resources with Electric Power Systems. This provided the basic technical requirements for interconnection. Second, the Federal Energy Regulatory Commission (FERC) issued Order 2003, the Large Generator Interconnection Procedure (LGIP) for interconnections over 20 MW. The LGIP was the model for FERC's Small Generator Interconnection Procedure (SGIP) in several ways and preceded the SGIP by two years. And third, the National Association of Regulatory Commissioners (NARUC) finalized its Small Generation Resource Interconnection Procedures (NARUC Procedures, 2003). NARUC submitted its new procedures to FERC in the early stages of the docket that led to FERC Order 2006, which set the SGIP/SGIA as the federal procedures.

The NARUC Procedures are the genesis of the three interconnection procedures other than CA Rule 21discussed in this paper, though the NARUC Procedures are not themselves widely referenced any longer because they have not been updated since 2003. In turn, CA Rule 21 is the source of many of the concepts in the NARUC Procedures, though their organizational structures differ.

The NARUC Procedures (and, to an extent, CA Rule 21) established:

- much of the application process
- many of the technical screens used in current rules
- a fast-track process for generators that passed the technical screens

- the 20-MW threshold adopted by the SGIP (CA Rule 21 has no capacity limit)
- the standard three-step structure for utility study of more complex generators (feasibility, impact, and facilities studies)
- the use of a standard form agreement between the utility and the customer
- reliance on IEEE 1547.

Beyond all of this, perhaps the most important contribution of the NARUC Procedures and CA Rule 21was their recognition of a fundamental dividing line between interconnection to transmission lines and interconnection to distribution lines. The NARUC Procedures and subsequent procedures uphold the traditional approach to transmission line interconnection, which allows extensive utility discretion to study proposed interconnections at great length at the applicant's expense. But for distribution line interconnections, the NARUC Procedures established that, under certain conditions, additional study is rarely required.

By the time the NARUC Procedures were being cited as exemplifying "best practices" in federal law, they were already being supplanted by other procedures. In August 2005, the Energy Policy Act of 2005 (EPAct 2005) required all state regulators and unregulated utilities, with over 500 million kWh of annual load, to consider the implementation of interconnection procedures. Referencing the NARUC Procedures indirectly, EPAct 2005, section 1254, states that agreements and procedures should be considered to:

> "promote current best practices of interconnection for distribute generation, including but not limited to practices stipulated in model codes adopted by associations of state regulatory agencies. All such agreements and procedures shall be just and reasonable, and not unduly discriminatory or preferential."

NARUC was the only "association of state regulatory agencies" with interconnection procedures and the obvious referent in this provision. EPAct 2005 established that regulators and utilities had one year from enactment of the law to begin their consideration of interconnection agreements and procedures and two years to finish their consideration.

"... the Energy Policy Act of 2005 (EPAct 2005) required all state regulators and unregulated utilities, with over 500 million kWh of annual load, to consider the implementation of interconnection procedures."

Although the two-year window established in EPAct 2005 has passed, the development of interconnection procedures is still actively underway in many states, often driven by state legislation requiring interconnection rules. Several states continued past the two-year deadline of August 8, 2007, with the implicit or explicit reasoning that consideration of whether to implement rules was made by the deadline, while the initial rulemaking could extend beyond that date. For example, Illinois explicitly made this argument by the deadline and adopted its interconnection procedures in August 2008.

For those reviewing EPAct 2005, it seems that, on cursory review, all utilities are required to adopt interconnection procedures. In fact, EPAct 2005 places what appears to be a requirement into the Public Utility Regulatory Policies Act of 1978 (PURPA), but the placement within PURPA actually makes the provision less than a requirement. EPAct 2005 § 1254(a) adds a "federal standard" to PURPA § 111(d), and PURPA § 111(a) says that state regulators and "each nonregulated utility" have to consider adopting the federal standards in § 111(d) but are not required to do so. The interconnection provisions placed into PURPA by EPAct 2005 are at PURPA § 111(d)(15) (or see 16 U.S.C. § 2621(d)(15)). PURPA applies to state utility commissions and to unregulated utilities with sales of over 500 million kWh per year, which is approximately 57 average MW.

Despite being referenced in EPAct 2005, the NARUC Procedures are rarely reviewed by state regulators developing procedures. Instead, for various reasons, the SGIP/SGIA, the MADRI Procedures, and the IREC Procedures have been used, along with various state interconnection procedures.

NNEC's *Freeing the Grid*

The Network for New Energy Choices (NNEC) first published *Freeing the Grid* in 2006 to analyze and compare net metering and interconnection rules from all of the states. In 2007, NNEC teamed with the Solar Alliance, the Vote Solar Initiative, and IREC to refine and expand its analysis. Thirty-four states and the District of Columbia had interconnection procedures as of the publication of the 2008 report and received letter grades based on sixteen criteria. The SGIP/SGIA is used as a reference point for grading, with a score of zero for each criteria and an overall grade of "C." The 2008 edition of *Freeing the Grid* was published in October 2008.

The analysis section of this paper is divided into the sixteen scoring criteria with analysis of each of the four interconnection procedures under each criterion. Briefly, the sixteen criteria are as follows:

1. Eligible technologies—deduction if not comprehensive
2. System capacity—deductions for capacity limits under 20 MW
3. Breakpoints—credit for applicant tracks, deduction for single approach for all applicants
4. Timelines—credit for faster than SGIP; deduction for slower
5. Interconnection charges—credit for application fees lower than SGIP; deduction for higher
6. Engineering charges—credit if fixed rather than variable
7. External disconnect switch—credit if prohibited; deduction if required
8. Certification—deduction if IEEE 1547 is not followed; credit for self-certification
9. Technical screens—deduction for screens beyond SGIP; credit for easier screens than SGIP unless safety is affected
10. Spot network—credit if systems over 50 kW allowed, deduction if not allowed
11. Area network—credit if clearly allowed; deduction if not allowed
12. Standard form agreement—credit if easier than agreement under SGIP; deduction if harder or left to utility discretion
13. Insurance requirement—credit if prohibited; deduction if required
14. Dispute resolution—credit if simplified and low cost
15. Rule coverage—credit if applicable to all utilities in state, zero if only applicable to investor-owned utilities
16. Miscellaneous—catchall for other issues (rarely used)

Any scoring methodology can be criticized and, certainly, *Freeing the Grid* will refine its criteria and scoring methodology in future years, but fundamentally, the publication offers a valuable service. State regulators considering a specific issue can look to *Freeing the Grid* to see how other states have addressed that issue. States with the lowest scores have almost no distributed generation, and it is reasonable to correlate those facts. Thus, if state regulators hope to encourage the installation of distributed generation, they can see which state procedures to avoid and which to consider.

All of the entities participating in development of the 2008 NNEC scoring criteria favor widespread installation of solar energy systems, which raises the question of whether safety, grid reliability, and cost issues are fairly addressed. Put another way, a reasonable criticism of the NNEC criteria is that a state rule that simply required all systems to be quickly interconnected at no cost to the customer would receive an "A." However, even such a simple rule would essentially come down to a matter of cost allocation between interconnection customers and ratepayers. Utilities would still have a duty to assure safe and reliable service and could comply with the simple interconnection rule by having staff and equipment on hand to respond to all interconnection requests rapidly.

Only five of the NNEC criteria relate to safety in any way: criteria 7 through 11. Regarding criteria 8 through 11, utilities argue that a relaxation of certification requirements, expansion of fast-track screens, or inclusion of network interconnection procedures may compromise reliability, and thereby, safety. In each case, the NNEC counters that reliability can be maintained while allowing some easing of the SGIP/SGIA procedures on which the scoring is based. The argument seems sound; the United States and other nations have much more experience with interconnection of distributed generation than was the case in 2005 when the SGIP/SGIA was implemented. The SGIP/SGIA set very cautious or incomplete standards on these points, and reconsideration is appropriate.

Safety is also asserted to be an issue with respect to criteria 7, regarding the external disconnect switch. Again, the NNEC believes that the experience of the past three years should inform policy. An extensive analysis by the US DOE's National Renewable Energy Laboratory (NREL) concluded in 2008 that the switches are unnecessary for systems under 10 kW. As well, a study funded by the Solar America Board for Codes and Standards on the topic, due to be released in late 2008, reaches a similar conclusion. New Jersey has prohibited utilities from requiring the switches with no adverse effects, and several states prohibit the requirement for small facilities. All of these factors support at least an easing of the requirement, indicating that the NNEC scoring is appropriate.

Cost is directly an issue in criteria 4 through 6, regarding timelines and charges. Complying with shorter timelines arguably takes additional staff, and the application fees or fixed engineering fees may not cover all of a utility's costs. It is essentially a policy issue to set these levels, and renewable energy advocates favor low fees and short timelines. However, this raises the question of cost allocation. Regulators often question whether ratepayers without renewable generation are paying higher rates without corresponding benefits to cover the expense of interconnecting their neighbors' solar arrays and other generators. The value of distributed generation to ratepayers is therefore scrutinized; value beyond delivered energy is often found in capacity, environmental, and back-up attributes.

Interconnection cost allocation between owners of distributed generation and utility ratepayers is a frequently raised issue. Utilities often stress the need to have the owner bear all costs, but there are several counter-arguments. First, distributed generation provides a system benefit of reduced demand on the electric grid, which has some positive value. Second, distributed generation is typically renewable, providing emissions reductions that are important to society, including utility ratepayers. Third, the costs realized in states with more experience in interconnecting distributed generation may serve as a guide justifying a limit on recoverable utility costs based on the cost to perform

the same function in other states. And fourth, program start-up costs per customer are very likely to be much higher than program costs per customer with a mature program, so establishing fees at a level that is below initial costs at early stages is justified to launch programs with recognizable benefits to utility ratepayers. As more experience is gained, the average cost to interconnect a system is likely to trend downward.

The remaining criteria have no affect on safety, reliability, or cost, but rather are structural. Among these is criterion 13, insurance provisions, which is typically based on a cost allocation argument. If something goes wrong with a customer's generator, utilities contend that other ratepayers should not bear the expense of damage to the utility grid. However, with over 50,000 solar arrays in the US, the authors are not aware of any case of line worker injury or significant utility property damage attributable to solar energy systems or any other systems. In any event, solar arrays are expensive assets that are almost always covered under a property owner's insurance. Such insurance would typically provide protection if damage or injury occur. In short, it appears unlikely that a prohibition on additional insurance requirements would have any cost impact for other ratepayers, but requiring additional insurance will add cost for the system owner.

To summarize, the NNEC grading methodology was created by solar energy advocates, but that does not mean that its results are unreasonable. Solar energy system owners, developers, and installers have a great deal of experience with interconnection issues. Many of these individuals came from the utility industry and appreciate the technical and administrative issues that utilities face when interconnecting distributed generation. The intent of the NNEC grading methodology is to foster the widespread installation of distributed generation in a way that does not compromise safety and reliability. In the authors' opinion, the NNEC grading methodology does that quite well.

Overview of the four interconnection procedures

Although this paper focuses on the differences between the SGIP/SGIA, CA Rule 21, the MADRI Procedures, and the IREC Procedures, their many commonalities establish a relative baseline of interconnection procedure essentials. These common elements are sometimes missing when state procedures are adopted; absence of any of these elements is a substantial hindrance and a cause for point deductions under the NNEC grading criteria.

Among the common elements of all four procedures under review here are the following:

- Coverage of all technologies, rather than just renewables
- Interconnection of systems up to at least 10 MW
- Pro forma interconnection agreements
- A simplified procedure for small solar arrays covering most residential installations
- A fast track procedure for systems up to 2 MW that allows interconnection without additional cost or delay if certain screens are met
- A scoping meeting if screens are not met to review expected costs and duration of studies
- A three-part study (feasibility, impact, and facilities) process for interconnection of more complex and larger systems (CA Rule 21 has an supplemental review process as a first step for systems that do not meet all of the screens and, failing that, a single study process that essentially includes the three study areas listed.)
- Comprehensive coverage of issues such that utility discretion to create substantive additional rules is largely foreclosed

A lack of basic elements such as these is a common theme among states receiving the lowest grades from NNEC.

While the analysis in this report focuses on differences between the procedures being reviewed, it is important to recall that there are central features to all of them. Background on each of the procedures and a summary of its grading under the NNEC criteria are provided below.

FERC's small generator interconnection procedures and agreement

FERC began the development of the SGIP in 2002 and, with extensive participation by utilities, regulators, renewable energy advocates, industry, and government experts, issued FERC Order No. 2006, on May 12, 2005. Accompanying the SGIP in Order 2006 was the Small Generator Interconnection Agreement (SGIA), a standard form agreement. Through subsequent orders, FERC developed its final version of the SGIP and SGIA on August 28, 2006, in Order 2006-B. It is this final version of the SGIP/SGIA that is reviewed in this paper.

The SGIP's significance rests in its application for large distributed generators, its widespread adoption, and its function as a model for state procedures. For interconnection of distributed generators under a few megawatts, which is the vast majority of such interconnections, it is rarely applicable.

Order 2006 requires all public utilities that own, control, or operate facilities under the FERC's jurisdiction to file standard procedures, the SGIP, and a standard agreement, the SGIA, to interconnect generating facilities up to 20 MW. FERC has jurisdiction over utility high-voltage transmission lines, but, except for limited situations, FERC does not have jurisdiction over distribution systems. One exception is that FERC may claim jurisdiction over a distribution line when a "non-qualifying facility" generator interconnects to a distribution line covered by a public utility's Open Access Transmission Tariff to make wholesale sales of electricity (FERC Order 2006, §§ 465-491, reviewing FERC's jurisdiction).

Distributed generators under a few MW rarely interconnect under the SGIP because they are typically interconnecting to state-jurisdictional distribution lines for the purpose of serving on-site load, not consummation of wholesale sales. In practice, it typically costs much more and takes much longer to interconnect a small generator to a transmission line than a distribution line, so developers typically try to interconnect smaller generators to a distribution line whenever feasible. As well, most smaller distributed generation systems are intended to serve the onsite load of utility customers that are located on a distribution system rather than a transmission line. Because the SGIP does not apply to these distribution line interconnections, state procedures or utility-specific procedures typically govern these interconnections.

Distributed generation systems larger than a few MWs are more likely to interconnect using the SGIP. There are two reasons. First, the likely cost of distribution circuit upgrades will dissuade applicants from proposing that their large systems interconnect on distribution lines. Second, relatively few distribution-served customers have loads larger than a few MWs, so larger systems are typically interconnected with the purpose of making wholesale sales.

Because most utilities (other than the very smallest) own or operate FERC-jurisdictional utility lines, they are required to adopt the SGIP for interconnections to such lines. For these utilities, there is a rationale to seek similar procedures for distribution lines that are subject to state jurisdiction. This rationale has not however been strong enough to lead to widespread adoption of the SGIP by states. State utility commissions tend to defend their jurisdiction against encroachment by FERC and feel no obligation to start with the SGIP in developing their state interconnection procedures. In addition, utilities, who are active and well connected participants at state commissions, may see an opportunity to seek more restrictive provisions than SGIP provides. As a result, although the SGIP may serve as a model in limited respects, state utility commissions often do not adopt it in its entirety.

Utilities not subject to state utility commission oversight typically do not bother to adopt interconnection procedures at all. EPAct 2005 required utilities with sales over 500 million kWh per year to consider adopting interconnection procedures. Many considered such procedures but decided not to adopt them.

California's Rule 21

Years before the NARUC Procedures, the SGIP, the MADRI Procedures, and the IREC Procedures were adopted, California was developing its own interconnection procedures. While not adopted elsewhere (other than Nevada), CA Rule 21 governs the majority of U.S. distributed generation interconnections due to the impact of California's solar incentives and various state policies related to distributed generation. A significant majority of U.S. solar energy systems and other distributed generators are installed in the service territories of California utilities that utilize CA Rule 21.

CA Rule 21 was drafted through a cooperative effort of stakeholders, including California's two principal energy agencies and the state's investor-owned and key municipal utilities. The effort started in October 1999 when the California Public Utilities Commission (CPUC) opened a rulemaking to address interconnection procedures. One month later, the California Energy Commission (CEC) began an investigation of policies to encourage distributed generation. The CEC presented its findings in the CPUC's rulemaking and this progressed into drafting CA Rule 21.

CA Rule 21 specifies standard interconnection, operating, and metering requirements for distributed generators that interconnect to the distribution system of a CPUC-jurisdictional utility, including Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E). These utilities are required to adopt Rule 21 as a part of their tariffs. Although California utilities each have their own version of Rule 21, the versions are substantially identical except for references to utility names and tariff sections. Many California municipal utilities have also adopted interconnection procedures modeled after Rule 21, including the Los Angeles Department of Water and Power and the Sacramento Municipal Utility District (SMUD).

CA Rule 21 applies the same review process regardless of the size of a proposed generator. All interconnections start with an initial review, which applies eight screening criteria to determine whether a generating facility qualifies for a simplified interconnection. Failure to pass a screen does not mean that a generating facility cannot be interconnected; it only means that further review is necessary. Initial review determines whether a generating facility qualifies for a simplified interconnection, whether it may be made to qualify for a simple interconnection through a supplemental review, or requires an interconnection study. Generators that do not export power and are small compared to an on-site customer's load will likely qualify for a simplified interconnection.

"CA Rule 21 was drafted through a cooperative effort of stakeholders, including California's two principal energy agencies and the state's investor-owned and key municipal utilities."

Unlike other interconnection procedures, including the SGIP, CA Rule 21 does not explicitly provide for a separate interconnection process for systems under 10 kW. However, facilities under 11 kW do take an abbreviated path through initial review by automatically satisfying three of the eight screens applied during initial review. As such, CA Rule 21 arguably provides a separate, expedited review despite its lack of an explicitly identified separate process.

Also unique among the procedures reviewed here, CA Rule 21 does not specify a system size limit to which the rule applies. There are significant advantages to this approach. First, under the federal Public Utility Regulatory Policies Act of 1978 (PURPA), states have jurisdiction over interconnections of certain generators, termed "qualifying facilities," when their entire output is sold directly to an interconnected utility. State jurisdiction applies in such situations regardless of the size of the generator and regardless of whether the interconnection is to a transmission or distribution line. Second, states have jurisdiction over large distributed generation systems (> 20 MW) when those systems are used entirely to serve on-site load. For example, several refineries in Southern California operate distributed generation systems larger than 20 MW to provide electricity and process heat. Third, some utilities operate subtransmission systems that are under state jurisdiction and can accommodate systems larger than 20 MW. By establishing an upper limit to the applicability of a state interconnection standard, regulators may leave certain qualifying facilities, subtransmission systems, and large systems that serve on-site load without an applicable interconnection standard.

Table 1 below presents the number of systems of all types reviewed under Rule 21 Procedures for California's three main investor-owned Utilities: San Diego Gas and Electric, Southern California Edison, and Pacific Gas and Electric. These totals were compiled from data provided to the Rule 21 workgroup by the IOUs, from California Solar Initiative program data (https://csi.powerclerk.com/CSIProgramData.aspx) and from the California Energy Commission.

Table 1. Number of Systems Reviewed Under California Rule 21 Procedures

	PG&E	SCE	SDG&E	TOTAL
< 1 MW**	6,381	9,852	23,015	39,248
1MW - 10MW**	261	717	66	1,044
10 MW - 20MW	-	47	14	61
> 20MW	11	18	6	35
TOTAL	**6,653**	**10,634**	**23,101**	**40,388**
Largest single Application	51 MW	97 MW	25 MW	

*** — because of a small amount of possible overlap in the various data sources, these numbers are estimated*

Under CA Rule 21, generators passing the initial review process only incur application review fees. However, interconnection review fees, as well as any interconnection study fees and distribution system modification costs, are waived for generators eligible for net energy metering (Cal. Public Utilities Code § 2827). State legislation also waives the first $5,000 of application fees, interconnection studies fees, and distribution system modification costs for solar generating facilities up to 1 MW that do not sell power to the grid.

A clear and well-organized guidebook on California's Rule 21 is available on the California Energy Commission's website, as well as a supplemental review guide for addressing systems that fail one or more of the initial review screens.

MADRI small generator interconnection procedures

The MADRI Procedures were finalized in November 2005 by the utility commissions of Delaware, New Jersey, Maryland, Pennsylvania, the District of Columbia, the PJM Interconnection (the regional transmission organization for the states just listed), and various federal agencies (FERC, the Department of Energy, and the Environmental Protection Agency). These stakeholders developed their procedures as an alternative to

the SGIP, which came out six months earlier. In its model form, it was not meant to be applied anywhere, but the drafters intended that utilities and state regulators in the PJM Interconnection states would adopt the new procedures. All non-utility parties to the SGIP devoted years of attention to the SGIP process, which limited non-utility participation in the MADRI Procedures development. As a consequence, the procedures fell short on some key provisions and received a low "C" grade from NNEC. However, on many important issues, the MADRI Procedures are exemplary, and they are the basis of newly adopted procedures in Illinois and Oregon that are among the best in the nation.

Among the states in the PJM Interconnection, Pennsylvania adopted the MADRI Procedures in significant part, Maryland completed a rulemaking in June of 2008 with adoption of rules improving upon the MADRI Procedures, and the District of Columbia has initiated a rulemaking to consider similar rules. Delaware developed interconnection procedures with very low system capacity, along with other poor terms. None of these states have significant solar energy installations or other installations. New Jersey elected not to adopt the MADRI Procedures and developed what NNEC considers one of the best state procedures in the U.S. and now has the second most solar installations in the country. While the principal reason for New Jersey's success is its generous solar incentive program, its interconnection procedures helped facilitate the success.

Outside of the PJM Interconnection, the MADRI Procedures have been used in Illinois, Oregon, and are under consideration in Utah and South Dakota (which are considering Oregon's improved version). The procedures have had significant impact on state rulemakings, though limited association with successful state solar programs. With both Oregon and Maryland appearing to be on the verge of major growth in solar installations due to state incentive programs, it appears that the MADRI Procedures will be tested significantly, though both states improved the MADRI Procedures in multiple ways.

Two significant benefits of the MADRI Procedures can be attributed to the involvement of the Regulatory Assistance Project, which acted as a DOE-funded moderator in the development of the procedures. First, it established a third tier for applicants who would not export to the grid. Many large commercial solar systems are sized at well below the average usage of the building on which they are located, creating an opportunity to ignore SGIP technical screens regarding grid impacts caused by exported energy. In practice, the MADRI Procedures allows utilities the discretion to not abide by the rules for non-exporting generators, but the concept is good.

The second benefit of the MADRI Procedures is that it is well documented, with options for provisions that state regulators may want to consider. Many of these options create what the NNEC would consider a better rule. This facilitates transforming the MADRI Procedures into state procedures that would grade at higher levels, as has occurred in Maryland, Illinois, and Oregon. In practice, it would be more productive for regulators to start with the Illinois or Oregon procedures than with the MADRI Procedures themselves.

To facilitate complete rules for each of its four tiers, the MADRI Procedures are repetitive, with a great deal of identical language appearing in the description of requirements for each tier. As well, in its desire to document party comments extensively, MADRI allowed its procedures to stretch to 41 pages, plus 88 pages of attachments. This adds considerable length to the procedures and hinders change, since any desired change has to be effectuated at multiple points. By comparison, the SGIP is 14 pages with 79 pages of attachments (including the SGIA) and the IREC Procedures are 12 pages with 40 pages of attachments.

IREC's interconnection procedures

Through its participation in state and federal development of interconnection rules, the Interstate Renewable Energy Council has had extensive exposure to the various approaches taken. For instance, in 2007, IREC was active in the development of interconnection rules in New Mexico, Illinois, Florida, North Carolina, Utah and to a lesser extent, Maryland and Washington, DC.

The IREC Procedures were initially developed in 2005, with the final version analyzed here produced in November 2006. The intent of the procedures was to respond to EPAct 2005's call for states to consider adoption of best practices by creating its version of what best practices were as of late 2006. Coming at a later date than other procedures discussed in this paper, the IREC Procedures draw on SGIP/SGIA, the MADRI Procedures, the NARUC Procedures, and the progressive rules developed in New Jersey.

The IREC Procedures drew directly from the SGIP for its basic format, technical standards, application forms, and the simplified agreement for interconnection of inverter-based systems no larger than 10 kW (which is an exhibit to the SGIP and not part of the SGIA). In large part, the IREC Procedures also adopted the SGIA for any interconnections that require utility system upgrades, though it actually adopts the MADRI Procedures' modified version of the SGIA for those more complex interconnections. From the older NARUC Procedures, IREC adopted the more streamlined agreement for interconnections that do not entail utility-system upgrades.

Recognizing the value of the MADRI Procedures' simplified approach to non-exporting generators, the IREC Procedures adopted this innovation and unlike the MADRI Procedures, made the provisions non-discretionary for utilities. While generally not adopted in a useable form by states, non-exporting generator provisions have compelling logic. That logic is that, all else being equal including generator size, it should be easier to evaluate a generator that does not feed power back to the utility grid than it is to evaluate a generator that does export power. This one provision could open a market for systems over 2 MW that would be subject to costly and time-consuming studies under most procedures.

For most timelines and application fees, the IREC Procedures looked to the New Jersey rules that continue to be more accommodating to industry. Seeing no evidence that these timelines and fees were leading to rate impacts or reliability concerns in New Jersey, IREC adopted those procedures as best practices in its current procedures.

Based on field experience for distributed generation, particularly solar arrays, IREC adopted two provisions to expand markets and lower costs where it did not appear that safety or reliability would be affected. First, interconnection to spot networks and area networks is allowed to reach the lesser of 10% of minimum annual load or 500 kW, which is far beyond the allowable levels in most state procedures. The authors are not aware of any incident or study indicating that network reliability would be impacted at these modest levels, indicating that the levels are appropriate. However, network connections are a contentious topic and some alternative such as a non-exporting requirement for larger systems may be part of an appropriate solution.

"Recognizing the value of the MADRI Procedures' simplified approach to non-exporting generators, the IREC Procedures adopted this innovation and unlike the MADRI Procedures, made the provisions non-discretionary for utilities."

Regarding the external disconnect switch, IREC took the position taken in New Jersey rules that there is no need for the switch and it should therefore never be required at a customer's expense. There has not been compelling evidence that these switches are used or necessary, so IREC's Procedures prohibit utilities from requiring a disconnect

switch. The conclusion of a 2008 study by the National Renewable Energy Laboratory was that the switch was unnecessary for systems under 10 kW, while not discounting its usefulness for larger systems.

Beyond the NNEC grading criteria, the IREC Procedures have a direct style and a shorter length that allows new users to grasp the rules quickly. The IREC Procedures were used extensively in Colorado and an earlier version of the IREC Procedures was the basis of New Jersey's procedures. In addition, the IREC Procedures are the basis of comments filed by IREC in dozens of states, with the result that many provisions have been adopted in state procedures.

Literature Review

As this analysis is largely a point-by-point review of four interconnection procedures, most of the literature review relates directly to discussion of the procedures by the bodies that developed them.

For the SGIP/SGIA, there is a complete record of comments filed in the docket leading to FERC Order Nos. 2006, 2006-A and 2006-B. In the final orders, each provision in the SGIP/SGIA is discussed at length, including party positions and resolution of the issue at stake. Among the filings in order No. 2006 is the NARUC Procedures, which was also reviewed for the discussion of its influence on all but CA Rule 21.

For CA Rule 21, California Public Utility Commission (CPUC) orders and proceedings were reviewed, along with the very approachable and informative California Interconnection guidebook, *A Guide to Interconnection Customer-owned Electric Generation Equipment to the Electric Utility Distribution System Using California's Electric Rule 21*.

For the MADRI Procedures, the MADRI website listed in the references section of this paper provides presentations at all of the meetings leading to the development of the procedures. As well, the procedures themselves contain extensive commentary regarding party positions on various issues.

Finally, the authors represent IREC in state interconnection rulemakings and have the benefit of access to the developers of the IREC Procedures and the individuals who have shaped opinions leading to those procedures, including Jane Weissman, Chris Cook, Rusty Haynes, and Tom Starrs. Comments filed in various proceedings by Mr. Cook were particularly useful background material.

Material of a more generalized nature reviewed for this paper includes the 15-page IEEE 1547 standard that provides a foundation for all of the procedures herein, along with UL 1741 (Underwriter Laboratories' Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources) *Connecting to the Grid* (5th Ed., 2007) by Rusty Haynes and Chuck Whitaker provided useful material on technical requirements for interconnection in particular.

Analysis

The sixteen NNEC grading criteria used in *Freeing the Grid* (2008) are reviewed below, with a description of how each of the four procedures performed under each criterion.

1. Eligible Technologies

All four procedures cover a full range of technologies, not just renewables. The SGIP facilitates interconnection of any "devise for the production of electricity." CA Rule 21 covers interconnection of all devices that convert "mechanical, chemical, or solar energy into electrical energy." The MADRI Procedures encompasses interconnection of Small Generator Facilities and defines that term as equipment rated at 10 MVA or less, with no restriction on eligible technologies. The IREC Procedures open with the statement that there are four review paths for interconnection of customer-sited generation without providing technology-based restrictions.

Under the NNEC grading, failure to encompass all technologies results in negative points. It would be needlessly duplicative to have separate rules for renewable energy generators and non-renewables. All four procedures received a score of zero, the highest score.

2. System Capacity

The SGIP covers facilities with a maximum rated capacity up to 20 MW. CA Rule 21 does not establish a specific size limit and therefore receives the maximum score of zero. The MADRI Procedures set a cap of 10 MVA, which acts as a lower cap than 10 MW if reactive power is also produced. The IREC Procedures set a 10 MW cap.

NNEC changed its scoring in 2008 to set the SGIP's 20 MW cap as the highest score (zero), with -0.5 attributed to procedures using a 10 MW cap. The IREC and MADRI Procedures each receive this small deduction. In former editions, *Freeing the Grid* did not have a deduction for procedures with a 10 MW cap. In future editions, a further credit for applicability to systems over 20 MW may be enacted to ensure that there is not a gap in state and federal procedures that leaves larger "qualifying facilities" without an applicable standard.

In practice, systems over 10 MW are likely to interconnect on transmission lines, meaning the SGIP would likely be applicable. However, if such systems certify as qualifying facilities and their full output is sold to an interconnected utility, state interconnection procedures apply regardless of the size of the generator and regardless of whether the interconnection is to a transmission or distribution line. In addition, FERC has declined jurisdiction over transmission-line interconnection of at least two generators in excess of 10 MW. Thus, limiting state interconnection standards to systems of a particular size may create a gap between state and federal interconnection rules.

3. Breakpoints

The SGIP includes three alternative procedures for evaluating an interconnection request depending on the size of a proposed system. NNEC scoring awards one point for four or more procedures based on system size or other features, awards zero points for having three procedures, deducts a point for only having two procedures, and deducts two points for having only one procedure.

The SGIP's Level 1, a "10 kW Inverter Process," is available for inverter-based systems under 10 kW that either meet certain codes, standards, and certification requirements stated in the SGIP or are determined safe to operate by an interconnecting utility after it has reviewed the design for or tested a facility (SGIP § 1.1.1 and Attachments 3 & 4). Level 2, a "Fast Track Process," is available for facilities no larger than 2 MW that meet the same list of codes, standards, and certification requirements or that are

determined safe to operate, but Level 2 applicants need not be inverter-based. Both the 10 kW Inverter Process and the Fast Track Process evaluate systems using a series of technical screens (SGIP § 2.1 and Attachment 5). The main distinction between the 10 kW Inverter Process and the Fast Track Process, besides the inverter requirement for the small systems, is that the 10 kW Inverter Process uses a simplified application and interconnection agreement. Level 3 is a four-step "Study Process" that is available for facilities up to 20 MW that do not qualify for the Fast Track Process or the 10 kW Inverter Process. The Study Process includes a scoping meeting, feasibility study, system impact study, and facilities study (SGIP §§ 1.1.1 & 3.1).

In contrast to the SGIP, CA Rule 21 applies the same evaluation process regardless of the size of a proposed generator. The process starts with an initial review, which applies eight screening criteria to determine whether a generating facility qualifies for a simplified interconnection (CA Rule 21 (C)(1)(c)). Failure to pass a screen does not mean that a generating facility cannot be interconnected; it only means that further review is necessary. Although a system of any size could qualify for a simplified interconnection, the screens favor systems that are small compared to on-site load and systems that are not expected to export power. In fact, facilities under 11 kVA take an abbreviated path through initial review by automatically satisfying three of the eight screens applied during initial review (CA Rule 21 (I)(3)). If an initial review determines that a proposed generating facility can be interconnected by means of a simplified interconnection, a utility will provide a customer with a written description of the interconnection requirements and an executable interconnection agreement (CA Rule 21(C)(1)(c)(2)).

If a CA Rule 21 interconnection request fails the initial review screens, a utility may perform a supplemental review to determine whether (i) the failure may be inconsequential to the safe operation of the distribution system, (ii) a minor alteration to the proposed interconnection will address the failure, or (iii) an interconnection study is needed. Under the first two of these outcomes, a simplified interconnection may still be appropriate. If, however, a supplemental review reveals that a proposed generating facility cannot be interconnected to a utility's distribution system by means of a simplified interconnection or that significant upgrades to the utility's distribution system will be required to accommodate the generating facility, the utility will need to perform an interconnection study (CA Rule 21(C)(1)(d)). If an interconnection study is needed, an applicant will be provided an estimate of the cost and time necessary to complete the study. The applicant may either authorize the study or cancel the application. Cancellation may be preferable if the cost of interconnecting appears too high. Recognizing that CA Rule 21 provides a simplified procedure and a standard study process in practice, CA Rule 21 is given a score of -1.

The MADRI Procedures have four levels for interconnection review. Like the SGIP, there is a simplified procedure for small, certified, inverter-based generators (MADRI Procedures § 4). The list of certification codes and standards is the same between the two, and the MADRI Procedures' 10 kVA breakpoint is the same as a 10 kW breakpoint for generators operating at unity-power factor (the usual case for solar arrays). The MADRI Procedures' Level 2 review process is restricted to inverter-based systems, excluding rotating generators that are allowed under the SGIP Fast Track Process (MADRI Procedures § 5.1.1 and comment following). This is a major limitation of the MADRI Procedures, as it forces all rotating generators into a study process that will involve longer timelines, utility

discretion, and study costs. For generators over 2 MVA, a study process similar to the SGIP process is provided as Level 3 (MADRI Procedures § 6).

The MADRI Procedures also include a Level 3A that gives utilities broad discretion to allow interconnection of non-exporting systems no larger than 50 kVA to an area network or no larger than ten MVA to a distribution circuit (MADRI Procedures § 7). While the concept of simplified rules for interconnection of non-exporting generators is very positive, the fact that the utility has complete discretion makes the provisions unattractive to potential developers of generating facilities. Without certainty, developers will not take the first exploratory steps. For area network interconnections, the utility may pay for a study and deny the application if it determines "in its sole discretion" that there are potential adverse impacts of the interconnection (MADRI Procedures §§ 7.3.2.2 & 4.2). For non-exporter interconnection to distribution circuits, the procedures are only used "by mutual agreement" of the utility and the customer (MADRI Procedures § 7.4).

While the MADRI Procedures appear to have four levels and thereby deserve a score of 1 because they have one more breakpoint than the SGIP, it is the authors' opinion that MADRI Procedures are no better than the SGIP in this area. Level 3A is ineffective because it is entirely discretionary and Level 2 is restrictive in comparison with the SGIP because it excludes rotating generators, so overall, the MADRI Procedures are awarded a zero, equal to the SGIP.

The IREC Procedures have breakpoints for certified inverter-based generators no larger than 10 kW, a Level 2 fast track process for certified systems no larger than 2 MW, and a Level 4 study process for systems no larger than 10 MW. In addition, the IREC Procedures allow interconnection to area networks under Levels 1 and 2 (IREC Procedures §§ e, f & g), and they contain a Level 3 process for non-exporter interconnection to area networks and distribution circuits that is functional. For exceeding the scope of the SGIP tiers and introducing functional non-exporter rules, the IREC Procedures receive two points under the NNEC grading for this criterion.

The intent of this criterion is not to count up the number of levels and compare that to the three tiers in the SGIP. The point of having levels is to carve out as many types of interconnection as possible that can be approved without further study if quantifiable screens are met. For instance, any of the procedures discussed here could be improved by moving their first level cap to more than 10 kW, as several states have done. Likewise, utility discretion to pursue studies at the customer's cost will hinder market development and should be avoided unless necessary.

4. Timelines

Under all of the procedures reviewed in this paper, interconnection requires the completion of a series of steps, each having an associated timeframe. The NNEC grading criteria assigns a point to state interconnection procedures that establish overall timeframes that are shorter than the SGIP and subtracts a point if timeframes are longer. The SGIP requires an interconnecting utility to make reasonable efforts to meet all timeframes established for completing an interconnection unless the interconnecting utility and interconnection customer agree to a different schedule (SGIP § 4.1). If an interconnecting utility cannot meet a timeframe, it must notify the interconnection customer, explain the reason and provide an estimated time by which it will complete the applicable interconnection procedure.

Under the SGIP 10 kW Inverter Process and the Fast Track Process (§§ 1.3, 2.2 & Attachment 5), a utility has three business days after receiving an interconnection request to notify an interconnection customer that a request has been received and ten business days to notify an interconnection customer if a request is complete or incomplete. Within 15 business days of notifying an interconnection customer that an interconnection request is complete, a utility must perform an initial review using the screens in SGIP and notify the interconnection customer of the results. Within five business days of that determination, if a proposed interconnection passes the screens or is determined to be safe, reliable, and compliant with applicable standards, the utility must provide the interconnection customer an executable interconnection agreement.

The SGIP study process is lengthier and more detailed (§ 3 & Attachments 6, 7 & 8). Within ten business days of receiving a complete interconnection request, a scoping meeting must be held, unless otherwise mutually agreed by the parties. No later than five business days after the scoping meeting, a utility must provide an interconnection customer with either a feasibility study agreement or a system impact study agreement. Within 30 business days of an interconnection customer's agreement to conduct a feasibility study, the feasibility study must be completed and the feasibility study report transmitted. If a feasibility study shows no adverse system impacts and no additional facilities are needed, an interconnecting utility must provide an executable interconnection agreement within five business days. If a feasibility study shows the potential for adverse system impacts, the interconnecting utility must provide a distribution system impact study agreement within 15 business days of transmittal of the feasibility study report. A distribution system impact study must be completed and transmitted within 30 business days of a system impact study agreement being signed, and a transmission system impact study must be completed and transmitted within 45 business days if required. Once a required system impact study(s) is completed, within five business days, the interconnecting utility must prepare a system impact study report and send it to the interconnection customer along with a facilities-study agreement. A facilities study must be completed and transmitted within 45 business days of the receipt of a facilities study agreement if system upgrades are required and within 30 business days if no system upgrades other than interconnection facilities are required. After the facilities study is completed, within five business days the interconnecting utility must provide the interconnection customer with an executable interconnection agreement.

CA Rule 21 earns no points in this category. Under CA Rule 21(C)(1), within three business days of an initial request, a utility must provide sample agreements, an application, technical information, a listing of certified equipment, initial and supplemental review fee information, applicable tariff schedules, and information on metering requirements. The utility has ten business days from receiving an application for interconnection to acknowledge receipt and state whether the application is complete. If the application is complete, absent "extraordinary circumstances," a utility must complete its initial review within ten business days and complete a supplemental review, if required, within 20 business days. Generating facilities that qualify for net metering are normally accommodated no later than 30 business days following a utility's receipt of a completed, net energy metering application, including all supporting documents and required payments; a completed signed net metering interconnection agreement, and evidence of the applicant's final inspection clearance from the governmental authority having jurisdiction over the generating facility (CA Rule 21(C)(2)(d)).

The MADRI Procedures match the SGIP timelines for Level 1 generators (§ 4.4) but adds at least an additional two weeks to the Level 2 application process, depending on holidays. Recall that the MADRI Procedures restrict Level 2 to inverter-based systems, so the review process should generally be simplified in comparison to the review to be done under the SGIP. First, the MADRI Procedures add five business days to the review

of a completed application (§ 5.4.5) and then add an extra five days to the end of the process to send a completed agreement (§ 5.4.7). As well, the MADRI Procedures do not require notice within three days of receipt of an application, as the SGIP does, so a lost application can go undetected for roughly two weeks from the date it was sent, and the applicant will have to begin anew unless proof of mailing is available (§ 5.4.2.1).

The study process of the MADRI Procedures' Level 3 is slightly longer than the SGIP process. Rather than requiring a scoping meeting within ten days, as the SGIP does, the MADRI Procedures call for a ten-business-day review to determine whether the application is complete and ten more days to schedule the scoping meeting. (§ 6.3) This stretches the time for an initial meeting from two to four weeks if there are no holidays. Timelines for the feasibility, impact, and facilities to be conducted by the utility are provided in separate agreements and are similar to the SGIP timeline. For its slower timelines in Levels 2 and 3, the MADRI Procedures lose a point under the NNEC grading.

The IREC Procedures generally adopt the aggressive but achievable timelines used in New Jersey. For Level 1, it provides that the utility has three days to notify an applicant that an application has been received and an additional ten days to review the application (§ f). This is three days longer than the SGIP process, which has these events occurring simultaneously. However, the utility is required to send a customer a completed agreement within three days of successful completion of the review, which is two days shorter than the SGIP, so the IREC Procedures take one additional day when compared to the SGIP for Level 1.

For generators up to 2 MW, IREC's Level 2 process is slightly faster than SGIP (§ g). There are three extra business days for notice that the application is complete, the same 15-business-day review period but just three business days for notice that the application has been approved. This approval notice period is seven business days shorter than the SGIP process.

For generators subject to the IREC study process, the timelines are quite similar to the MADRI Procedures, with twenty days to a scoping meeting and the same study timelines provided in the study agreements. As noted, this is a slightly slower process than the SGIP has. IREC's timelines receive one point in *Freeing the Grid* (2008), because there is a faster timeline for Level 2, which is the level most likely to have the majority of installed capacity.

A helpful provision that would be worthy of a 0.5 point credit, but is not included in *Freeing the Grid* (2008) or any of the procedures reviewed here, would be a requirement that utilities accept online applications and provide instant notification of receipt. Given that electronic communication is ubiquitous, there is no reason to build mailing costs and delays into the application process or to create a process that extends time periods in the event of lost applications.

5. Interconnection Charges

The SGIP requires a non-refundable processing fee of $100 for the 10 kW Inverter Process and $500 for the Fast Track Process (SGIP, Attachment 5 and § 2.4). If a supplemental review is required at the end of the Fast Track process, the interconnection customer must pay the actual costs of conducting the supplemental review. NNEC grading awards one point for interconnection charges lower than FERC's, negative one point for charges higher than FERC's, two points for waiver of fees for net metered systems, and negative three points for fees that are double FERC's level.

CA Rule 21 interconnection fees are slightly higher than SGIP's only in the cases of systems over 1 MW or non-solar, non-net-metered systems under 1 MW (CA Rule 21(C)(1)(d)). For these systems, an initial review fee of $800 must be included with an

application, with fifty percent of this fee returned to an applicant if an application is rejected by a utility or is withdrawn. If supplemental review is required for these systems, an applicant must pay an additional $600 (CA Rule 21(C)(1)(c)(3)).

Despite CA Rule 21 fees for the special cases discussed above, CA Rule 21 receives two points from NNEC because generators eligible for net energy metering are exempt from paying fees, including for any necessary studies, and solar-powered generating facilities up to 1 MW that do not sell power to the grid are also exempt from these fees in almost all cases (CA Rule 21(C)(1)(d)). Regarding these non-net metered systems, the California Public Utilities Commission stated that, "CalSEIA has made a persuasive argument that solar distributed generation installations under 1 MW impose negligible interconnections costs on the utility system; therefore, we will waive up to $5,000 in interconnection fees for solar distributed generation up to 1 MW" (CPUC Decision No. 01-07-027, 2001, p. 70).

The MADRI Procedures explain in the preamble that its process "deliberately does not prescribe levels for application fees" to allow individual jurisdictions to settle appropriate fees based on their circumstances. The procedures do state that fees for Level 1 applications are to be "nominal," but they do not settle on a number. Given the utility discretion to set fees, the MADRI Procedures loses a point on this criterion.

The IREC Procedures sets application fees of $20 for Level 1, $50 plus $1/kWh for Level 2, $100 plus $1.50/kWh for Level 3 (non-exporters), and $100 plus $2/kWh "as well as charges for actual time spent on the interconnection study" (§§ f, g, h & i). While IREC's scaled fees will end up costing the customer slightly more for systems near the top of the Level 2 and 3 ranges, it is better for the lower end of those ranges and superior for Level 1. For that reason, the IREC Procedures received a point in this category.

6. Engineering Charges

If an interconnection request is submitted under the SGIP Study Process, an interconnection customer must deposit the lesser of 50 percent of the estimated cost of performing a feasibility study or $1,000 (§ 3.3.2 and Attachment 6). Additional deposits, without limitation, may be required if a system impact study or facilities study are required (§ 3.3.2 and Attachments 7 & 8). Ultimately, an interconnection customer is responsible for paying all costs of performing a feasibility study, system impact study, and facilities study (SGIP attachments 6, 7 & 8). An interconnection customer is also responsible for paying the cost of all interconnection facilities and distribution system upgrades needed to accommodate an interconnection (SGIA §§ 4.1, 4.2). If transmission system upgrades are necessary, an interconnection customer is initially responsible for payment but is repaid through transmission access charge credits (SGIA § 5.2).

CA Rule 21 requires interconnection customers to pay for all costs reasonably incurred by a utility in reviewing, studying, and testing an interconnection (CA Rule 21(E)(2)). However, CA Rule 21 exempts generators that are eligible for net metering from paying the cost associated with interconnection studies and distribution system modifications (CA Rule 21(E)(2)(b) & (C)(1)(d)). CA Rule 21 also waives interconnection study fees of up to $5,000 for solar generating facilities with a capacity up to 1megawatt (MW) that do not sell power to the grid. (id.). For all other systems, applicants are responsible for all costs associated with installing interconnection facilities and all costs reasonably incurred by a utility in providing, operating, or maintaining distribution system modifications required solely for the interconnection of the applicant's generating facility. Payment requirements are contained in an interconnection agreement. Under NNEC grading, California receives a point for its waiver of fees for net metered systems and its $5,000 waiver for solar systems of 1 MW or less that do not sell power to the grid. The authors contend that such favorable allowances could justifiably be worth more than a single point.

The MADRI Procedures have the same basic provisions for engineering fees that SGIP has (MADRI Procedures § 6 and Appendices 3, 4 &5). For matching the SGIP, a score of

zero is allotted. To its credit, the MADRI Procedures do contain a deposit limit for each interconnection study while the SGIP only has a deposit limit on the feasibility study (MADRI Procedures Appendices 3, 4 &5). However, this does not significantly limit payments for the studies, just the timing of payments. Such provisions are helpful and should be considered for half-point awards in the future.

The IREC Procedures has the same study deposit caps proposed by MADRI and caps engineering costs at $100/hr (§ j), which was enough to earn a point. However, CA Rule 21 received the same score for policies that are far more generous to applicants; it would be appropriate to have further gradation for this criterion in the future, rather than having a single step from zero points to one point.

7. External Disconnect Switch

Given the exposure that this issue has had through a recent NREL study and a concurrent Solar ABCs study, the rationale for prohibiting an external disconnect switch requirement is not discussed here. NNEC awards one point for prohibiting the requirement, awards no points for ignoring the issue (as the SGIP does), deducts a point for leaving the requirement up to utilities, and deducts two points to procedures that require the switch. In 2008, the NNEC scoring for this criterion changed to award half a point credit for prohibiting a switch requirement for Level 1 installations, where the usefulness of the switch is the most suspect and the economic impact of requiring a switch is the most acute.

The SGIP does not require or prohibit an external disconnect switch for any size system, but it does direct 10 kW Inverter Process customers to check with the interconnecting utility before submitting an application to determine whether disconnection equipment is required (§ 4.0). The 10 kW Inverter Process also specifies that an interconnecting utility must have access to a disconnect switch if one is required.

CA Rule 21 does not require the use of an external disconnect switch, but an interconnected utility may require an interconnection customer to furnish and install a manually operated external disconnect switch, or comparable device. (CA Rule 21(D)(1)(d)). Only systems under 1 kW are exempt from this requirement and may not be required to install an external disconnect switch (CA Rule 21(D)(1)(d)). Given that the rule has a limited prohibition against the switch and two California utilities have dropped the requirement for certain small residential systems, CA Rule 21 appears to be at least as helpful as the SGIP on this issue on balance, and therefore receives a zero.

The MADRI Procedures leave installation of an isolation device entirely up to utilities at the customers' expense (§ 3.6.8). This provision results in a lost point and is clearly less progressive than CA Rule 21.

The IREC Procedures prohibit utilities from requiring a disconnect switch (§ j(5)). For that, it is given a point in the NNEC grading scheme.

In practice, the vast majority of installed systems are under 10 kW. As well, the referenced studies conclude that the disconnect switch is unnecessary for these small systems, but do not take firm positions on the usefulness of the switches for larger systems. Therefore, it may be appropriate to give full credit for elimination of the requirement for systems under 10 kW in the future.

8. Certification

All four procedures receive at least a score of zero on this criterion, meaning that they apply the IEEE 1547 (Standard for Interconnecting Distributed Resources with Electric Power Systems) and UL 1741 (Inverters, Converters, and Controllers used in Independent Power Systems) without significant modification. CA Rule 21 deviates from IEEE 1547, but these deviations are minor enough that CA Rule 21 is not penalized. The three explicit CA Rule 21 deviations relate to spot networks, protection from electromagnetic interference, and utilization of a higher system cap (CA Rule 21 uses a 20 MW cap while IEEE 1547 is limited to 10 MW)(CA Rule 21(D)), and some technical specifications are rewritten with the stated intent of maintaining conformity with IEEE 1547 (CA Rule 21(A)). In addition, UL 1741 certification alone is not sufficient in California, although a cumbersome review process eventually finds that virtually all UL 1741 certified equipment is certified for use in California. This needless administrative hurdle and the IEEE 1547 deviations could be acknowledged with a point deduction, but are not. It may be appropriate to adjust the CA Rule 21 scoring in the future. Instead, CA Rule 21 earns a point for self-certification provisions to allow the same type of unlisted generator to be installed in multiple locations without repetitious studies. The MADRI Procedures reference such an approach but do not require it, and therefore are scored the same as the SGIP, receiving a zero. The IREC Procedures have no self-certification provision and receive a zero as well.

9. Technical Screens

The SGIP applies a series of technical screens to interconnection requests that qualify for either the SGIP 10 kW Inverter Process or the Fast Track Process. If an interconnection request passes these screens, it must be approved (§ 2.2.2). If an interconnection request fails the screens, it must be studied under the SGIP Study Process, unless an interconnecting utility determines that a facility may be interconnected safely, reliably, and within power quality standards despite having failed the screens.

The SGIP applies the following technical screens (§ 2.2.1):

- The point of interconnection must be on a segment of the distribution system that is covered by the interconnecting utility's Open Access Transmission Tariff.
- If the interconnection is to a radial distribution circuit, the interconnection may not facilitate an increase in aggregated generation on the circuit that exceeds 15% of the line section annual peak load. A line section is a portion of an interconnected utility's electric system bounded by automatic sectionalizing devices or the end of a distribution line.
- The interconnection may not assist in contributing more than 10% to the distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of change of ownership.
- The proposed interconnection may not cause any distribution protective devices and equipment or interconnection customer equipment to exceed 87.5% of the short circuit interrupting capability.
- The proposed interconnection must use the correct type of interconnection to the primary distribution line given the type of electrical service provided to the interconnecting customer.
- If the proposed generation is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the new generation may not exceed 20 kW.

- If the proposed generation is single-phase and is to be interconnected on a center tap neutral of a 240-volt service, its addition may not create an imbalance between the two sides of the 240-volt service of more than 20% of the nameplate rating of the service transformer.
- The proposed generation may not increase the generation interconnected to the transmission side of a substation transformer feeding the circuit where the interconnection customer proposes to interconnect above 10 MW in an area where there are known, or posted, transient stability limitations to generating units located in the general electrical vicinity (e.g., three or four transmission busses from the point of interconnection).
- The proposed interconnection may not cause the interconnecting utility to construct facilities on its system.

NNEC grades state interconnection procedures by determining whether they have adopted the SGIP screens. A state interconnection procedure receives no points for adopting the SGIP screens and loses one point for a partial adoption of the SGIP screens. State procedures lose two points if no screens are used or the screens are left to utility discretion. NNEC assesses penalties if more conservative screens are used and bonuses if a state drops one or more SGIP screens that do not affect safety.

CA Rule 21 passes all interconnection requests through eight screens to determine whether they qualify for a simplified interconnection. If all the screens are passed, the generating facility qualifies for simplified interconnection. If a proposed interconnection fails any of the screens, the interconnection request proceeds to a supplemental review. Because the screens applied under CA Rule 21 differ from the SGIP screens, CA Rule 21 loses a point for this criterion.

Given that CA Rule 21 screens were developed and implemented well before the SGIP was adopted and most distributed generation is installed based on the CA Rule 21 screens, it is fair to ask why Rule 21 loses a point for this criterion. Moreover, CA Rule 21 screens appear to have some advantages over the SGIP screens. For example, there is no screen in CA Rule 21 related to exceeding the equipment interrupt rating, or limiting distributed generation on a shared secondary to 20 kW. In the SGIP, the 20 kW limit is in the aggregate, in CA Rule 21, it is per applicant. These advantages would appear to justify a reevaluation of the CA Rule 21 scoring for this criterion and perhaps a broader examination of the FERC screens to determine whether they may be improved upon.

The MADRI Procedures and the IREC Procedures have very similar provisions, adopting and improving upon the SGIP screens. Both adopt all of the screens listed, except the first SGIP screen that relates to FERC jurisdictional facilities and therefore would not be applicable in state procedures. Both the MADRI and IREC Procedures use a shortened version of the SGIP screens for Level 1 review. And both adjust the fourth screen slightly to state that the proposed interconnection may not cause any distribution protective devices and equipment or interconnection customer equipment to exceed 90% of the short-circuit interrupting capability, rather than 87.5% as the SGIP does. Several states have adopted this cutoff. For simplifying the SGIP screening process, both the MADRI and IREC Procedures receive a point.

10. Spot Network Interconnection

Networks are characterized as either area networks that may supply several city blocks, or spot networks that typically serve a single customer. Both use multiple transformers in an interconnected electrical network circuit to improve reliability. The SGIP requires facilities interconnecting to the load side of spot network protectors to use an inverter-based equipment package. The facility, together with other inverter-based generation, may not exceed five percent of a spot network's maximum load or 50 kW, whichever is less (§ 2.2.1.3).

Although CA Rule 21 addresses spot network connections, if a generating facility will interconnect to an area or spot network, it does not qualify for a simplified interconnection under CA Rule 21 and a supplemental review is required (CA Rule 21(I)(3)(a)). CA Rule 21 does not adopt IEEE 1547 Clauses 4.1.4.2 (Distribution Secondary Spot Networks), which is being studied for inclusion in a subsequent version of the rule (CA Rule 21(D)). CA Rule 21 receives no points for spot network interconnection, comparable to the SGIP, though a study process is required in California. Deduction of points is reserved for rules that prohibit spot network interconnection, and the cost of any necessary study is borne by the utility for net metered systems, so there is little impact on the customer generator in these typical cases.

The MADRI Procedures follow the approach of the SGIP and allow inverter-based generators to interconnect so long as aggregate generation on the network does not exceed the lesser of five percent of the spot network's maximum load or 50 kW (§ 5.3.2). As ever, matching the SGIP gets a score of zero.

The IREC Procedures allows aggregate inverter-based interconnection on a spot network of up to five percent of the spot network's peak load, without adding the 50 kW limitation. As many spot networks experience peak loads far in excess of one MW, this lifts the allowed spot network interconnection substantially while still maintaining a low threshold in percentile terms. For this, IREC is awarded two points in the NNEC grading.

The topic of spot and area network interconnections is being investigated by the National Renewable Energy Council and others, and results of these investigations may change the scoring of network provisions in the future. Yet, the authors conclude that with no evidence of network-interconnected systems causing harm, it is reasonable to assume that some process can be developed to allow fast-track review of such systems.

11. Area Network Interconnection

Major metropolitan areas such as New York and Chicago are served by area networks, which increase reliability and reduce outages in high-density load areas by using several primary feeders suitably interlaced through an area in order to achieve acceptable loading of transformers under emergency conditions and to provide a system of extremely high service reliability.

The SGIP does not address area network interconnections. CA Rule 21 addresses area network connections, however, only to the extent necessary to determine that a generating facility that interconnects to an area network does not qualify for a simplified interconnection under Rule 21 (CA Rule 21(I)(3)(a)). This allowance does not make interconnection to area networks any more feasible than it is under the SGIP, and CA Rule 21 is not awarded points. Generally, NNEC does not award a point for this criterion if studies are required because such a provision makes small systems uneconomic. CA Rule 21's requirement that utilities assume interconnection study costs for net metered systems would appear to facilitate area network interconnections, but it is still possible that the studies will determine that costly system upgrades are necessary to interconnect a system.

The MADRI Procedures have an extended process with utility discretion to permit area network interconnections of up to 50 kVA in the aggregate (§ 7.3). The utility may study the interconnection at its own cost and determine "in its sole discretion" that the interconnection will cause adverse system impacts. With that level of uncertainty, the MADRI Procedures are not credited with any substantive improvement in the ease

of making area network interconnections. However, the MADRI Procedures could be modified to allow area network interconnections.

Finally, the IREC Procedures do allow area network interconnection up to the lesser of 10% of minimum area network load or 500 kW (§ e(2)). The procedures are awarded two points for this, though scoring for this criterion will be reviewed in the future based on the results of studies related to area network interconnections.

12. Standard Form Agreement

In Order 2006, the FERC established a standard Small Generator Interconnection Agreement (SGIA) that must be signed by an interconnection customer and interconnected utility after a proposed interconnection has been successfully evaluated under either the Study Process or the Fast Track Process. The SGIA describes the legal relationships of the parties, including who pays for equipment modifications to the interconnecting utility's system to accommodate the interconnection. There is no separate agreement for interconnections evaluated under the 10 kW Inverter Process. Instead, customers with generators under 10 kW agree to abide by certain terms and conditions when they submit an application under the 10 kW Inverter Process.

California utilities have three to five different interconnection agreement forms each, which vary depending on whether the applicant is a utility customer or a third party. All utility agreements are CPUC-approved. Simple interconnections use simple forms, which is an improvement over the SGIP approach of using a lengthy document. Also, the third-party ownership model has become the leading way to finance larger commercial solar arrays, so it is helpful to have standard forms that address this type of ownership. Despite its positive aspects, CA Rule 21 gets a score of zero due to the burden of having so many contracts rather than just a few with statewide application.

The MADRI Procedures adhere to the basic format of the SGIP for its forms without simplification or added complexity and is given a score of zero. The IREC Procedures adopt the standard agreement from the NARUC Procedures for interconnections that will not require upgrades to the utility's system. Without that complexity, the agreement is a straightforward six-page contract, rather than the 34-page SGIA. For this, IREC is given a point.

13. Insurance Requirements

The SGIP 10 kW Inverter Process requires parties to follow all applicable insurance requirements imposed by the state in which the point of interconnection is located. (SGIP, Attachment 5) Insurance requirements for other SGIP interconnections are contained in SGIA Article 8. Under those requirements, an interconnection customer must maintain general liability insurance of an amount sufficient to insure against all reasonably foreseeable direct liabilities given the size and nature of the generating equipment being interconnected, the interconnection itself, and the characteristics of the system to which the interconnection is made. An interconnection customer of sufficient credit-worthiness may self-insure for such liabilities.

CA Rule 21's insurance provisions are scattered among multiple standard forms. PG&E, the largest utility in the state, provides that owners of net metered solar and wind systems under one megawatt and over 30 kW are only required to obtain insurance if they fail to abide by any of the operational, safety or legal requirements that they commit to do under their interconnection agreement (PG&E Form 97-978). Insurance is not required at all for net metered solar and wind systems up to 30 kW (PG&E Form 79-1101). In general, insurance is required for other generators. In short, insurance is not mandated automatically for most systems, so CA Rule 21 receives a point for its insurance provisions.

The insurance provision in the MADRI Procedures' standard agreement encourages the customer to carry adequate insurance, but do not require it (Appendix 7, Article 7). Such a provision recognizes the relatively low risk involved and the likelihood that the customer has adequate liability insurance already without requiring utility oversight. Such a provision gets the maximum score of one. The IREC Procedures have a similar provision in their standard agreement and also receive a point (Attachment 5, Section 13).

14. Dispute Resolution

The SGIP provides a dispute resolution process (§ 4.2). If a dispute is not resolved within two business days after receipt of written notice, either Party may contact FERC's Dispute Resolution Service (DRS) for assistance in resolving the dispute. The DRS assists the parties in either resolving the dispute or in selecting an appropriate dispute resolution venue. Parties split the cost of paying a neutral third-party arbiter. If neither party seeks assistance from the DRS, or if an attempted dispute resolution fails, either party may pursue legal action. An identical dispute resolution procedure is contained in Article 10 of the SGIA.

CA Rule 21 also establishes procedures to be followed in the event of a dispute. Under this process, disputes must be reduced to a writing that contains the facts of the dispute and a request for relief (CA Rule 21(G)(2)). Within 45 calendar days of a dispute letter being sent, authorized representatives must meet and attempt to resolve it. If a resolution is not reached within 45 calendar days, either party may request to continue negotiations for an additional 45 days; make a written request to the CPUC Chief Administrative Law Judge for mediation; or request mediation from an outside third-party mediator with costs shared equally between the parties. If the parties cannot resolve the dispute within 90 calendar days of a dispute letter being sent, the dispute must be submitted for resolution under the CPUC's Rules of Practice and Procedure Applicable to Customer Complaints. Due to the long delay–up to 90 days–between dispute occurrence and resolution, NNEC assigns a zero to CA Rule 21 for this criterion, indicating that CA Rule 21 provides for an administratively burdensome resolution process. The CPUC also provides an informal dispute-resolution process through its Consumer Services Division. Small disputes can be resolved through this process in as little as a few days. In many cases, this may offer a quicker dispute resolution process than the one provided for in CA Rule 21. Balancing these factors, CA Rule 21 is awarded zero points, equivalent to the SGIP/SGIA.

The MADRI Procedures' version of dispute resolution is an agreement that the parties will attempt to resolve disputes promptly, equitably, and in a good faith manner (§ 8.1). While most disputes can be settled by following such counsel, this does not adequately address how the parties are to handle disputes that will not settle on their own. On this point, the MADRI Procedures are given a zero for not addressing dispute resolution.

The IREC Procedures allow regulators to appoint a technical master with binding authority to resolve technical disputes (§ k(1)). The concept is that typical technical disputes related to interconnection have modest sums at stake and the parties would benefit from a prompt answer from an expert in a day rather than a thoughtful resolution by an arbiter in a month and accompanied by a sizeable cash outlay. The IREC Procedures receive two points on this issue.

15. Rule Coverage

In 2008, NNEC added a criterion for the extent of applicability of a state rule. Procedures applicable to all utilities within a state receive a point while procedures only applicable to investor-owned utilities receive no points. This new criterion is intended to credit certain states for having broadly applicable rules. For this criterion, the SGIP does not

fit comfortably as the standard against which others are compared. By definition, its score is set at zero, though the SGIP applies to all FERC-jurisdictional interconnections, including certain interconnections on public utility transmission and distribution lines. However, as noted earlier, state procedures are nearly always applicable rather than the SGIP.

None of the procedures reviewed here call for statewide coverage, and state procedures typically determine the reach of state interconnection rules based on the jurisdiction of the state utility commission. The level of jurisdiction over municipal utilities, co-operatives, and public utility districts varies from one state to the next. CA Rule 21 only applies to the state's investor owned utilities, so it receives a score of zero. Likewise, since the IREC and MADRI Procedures are silent on this point, they receive zeros.

16. Miscellaneous

All but CA Rule 21 use the basic format of the SGIP/SGIA, and the authors consider this uniformity a useful benefit because industry and utilities are already familiar with the federal procedures. As a result, CA Rule 21 receives a point deduction for being significantly different in structure from the SGIP. The other three procedures receive scores of zero.

Conclusions

A summary of the grading of each of the four procedures is provided below, with a table provided at the end of this section. Recommendations based on this review are provided in the analysis section.

NNEC grading of the SGIP

The NNEC grading methodology is based on the SGIP, with scores of zero for every criteria and a "C" grade overall. In some cases, the SGIP sets the high bar, in many cases it is the average, and for some criterion, the SGIP is surpassed by many state rules.

The SGIP sets a reasonable standard for system capacity, accommodating interconnection of systems up to 20 MW. In practice, there is rarely a need for state procedures above 10 MW, so NNEC only deducts half a point for rules that have an upper limit of 10 MW capacity (larger systems typically will interconnect with FERC-jurisdictional transmission lines, so state procedures need not cover these larger systems). The SGIP's applicability to all technologies is the standard, though some states restrict interconnection procedures to only certain renewable technologies.

In several categories, a handful of state procedures exceed the SGIP, though most state procedures lag behind or are at the SGIP level. For example, timelines for review of systems has been shortened in some states, spot network interconnections are more widely accepted, and area networks are permitted (they are not discussed in the SGIP). External disconnect switches are not addressed in the SGIP, but are not required by utilities in New Jersey or Rhode Island or for certain small systems in California and Florida.

In other categories, the SGIP is routinely exceeded by state procedures. Application fees established by the states are generally lower, the dispute resolution process in the SGIP is regularly found to be inferior to state processes, state standard form agreements are often considered friendlier than the SGIP's agreement (the SGIA) and insurance is often prohibited at some level in state procedures (it is not required or prohibited in the SGIP).

From the standpoint of large system developers, investors and installers, the SGIP's "C" grade is superior in one way to state procedures with the same grade. That one clear superiority is that the SGIP is already thoroughly understood and interpreted. An investor or developer considering a project in a state with few large distributed generators has to investigate the state's procedures carefully to be sure there are no

provisions that might delay or block a proposed project. For installers, a consideration in entering a new state is whether the interconnection procedures are substantially different from those existing in states in which the installer already practices. As a broad generalization, national adoption of the SGIP, or any procedures, would be one of the most effective ways to allow the industry to mature and grow.

Note that interconnection scores for the SGIP/SGIA in Freeing the Grid (2008) are set at zero for each criterion, but totals for all state scores are adjusted by 7.5 to make the scores comparable to scores for net metering rules. Thus, the SGIP/SGIA has a total score of 7.5 despite having a score of zero for each criterion.

NNEC grading of CA Rule 21

The score for CA Rule 21 has increased since the 2007 edition of *Freeing the Grid*. Minor refinements in NNEC's grading methodology and reevaluation of CA Rule 21 increased the rule's score, reflecting its friendly provisions regarding interconnection costs for net metered systems and its prohibition of an external disconnect switch for very small systems. It scores two points higher than the SGIP, achieving a grade of "B,"placing it among the top eight state procedures in *Freeing the Grid* (2008).

CA Rule 21 now scores the same as the SGIP on the issue of external disconnect switches. California leaves it to utility discretion to determine whether an external disconnect switch should be required for most systems, which would result in California losing a full point for this criterion. However, California is one of only a few states that exempts the smallest systems, those under 1 kW, from being required to install an external disconnect switch, and PG&E, the state's largest utility, has used its discretion to decide not to require the switch for most residential systems. The SGIP does not take a position on the switches, which tends to leave the issue entirely up to utilities. In comparison, CA Rule 21 seems just as favorable, and therefore its score was increased from the score awarded in 2007, and arguably, CA Rule 21 deserves at least a modestly positive score for this criterion.

Also, California's Rule 21 had previously received no additional points for waiving or lowering application and study fees for net metering eligible applicants. Although NNEC grants a point for fixed engineering fees and CA Rule 21 effectively fixes these fees for most applicants at zero because fees are waived for net metered systems up to 1 MW, the lack of fixed fees for other systems resulted in a penalty score of minus one point in 2007. Given that most systems are likely to be net metered, and the no-cost provision is an especially favorable version of a fixed fee, CA Rule 21 is now awarded a score of zero. Arguably, CA Rule 21 deserves a modestly positive score for this criterion as well.

CA Rule 21 does fail to adopt IEEE 1547 entirely, for which a point deduction is arguably justified, but its digressions from IEEE 1547 do not appear to be substantial.

NNEC grading of the MADRI Procedures

In many respects, the MADRI Procedures follow the direction taken by the SGIP/SGIA and therefore score a zero on many criteria. As discussed, the SGIP/SGIA scores of zero is the high score in eligible technologies and system capacity, so the MADRI Procedures are in good company on these points. Like most state procedures and the SGIP, the MADRI Procedures have very limited allowance for network connections, and therefore do not get credited under NNEC's grading for area and spot network interconnections. Its forms and agreements are not substantially different from the SGIP/SGIA's forms and agreements, and the MADRI Procedures take no new direction regarding system certification or technical screens, remaining tied with the federal procedure on those points as well. The MADRI Procedures score 1.5 points below the SGIP/SGIA, receiving a low "C."

The MADRI Procedures improve upon the SGIP/SGIA with respect to insurance provisions, which are addressed by not requiring customers to carry special insurance for their generators or to add special provisions to their insurance policies. Also, the MADRI Procedures can fairly be considered superior to the SGIP/SGIA with regard to its adoption of a fourth tier for review, which it titles Level 3A rather than Level 4. Level 3A covers non-exporting generators, and while it is not mandatory for utilities to approve these generators if they pass the stated screening process (and therefore receives no credit in scoring), at least the innovative approach is included.

In four respects, the MADRI Procedures fall short of the SGIP/SGIA. First, they force all non-inverter based generators to seek approval through a study process at applicant's cost, which will impact the economics of many otherwise viable applicants proposing rotating generator technologies.

The second shortcoming of the MADRI Procedures is that they require the external disconnect switch (referenced as an isolation device). The MADRI Procedures provide half a page on the requirement, describing how and where the switch can be installed for small generators, all of which could simply be deleted based on the apparent lack of need for disconnect switches on smaller generators at all.

Third, the MADRI Procedures allow cost-based application fees without specifying actual amounts. Cost-based fees will result in very high fees for the earliest customers of a particular utility while the utility learns how to analyze interconnections, and cost-based fees give utilities little incentive to reduce costs. On the issue of costs, it should be noted that the MADRI Procedures do set upper limits on required deposits for interconnection studies for larger generators, which is a substantive improvement over the SGIP/SGIA.

Fourth, the MADRI Procedures also fall short of the SGIP/SGIA with respect to dispute resolution procedures. The only requirement is that the parties attempt to resolve disputes "promptly, equitably and in a good faith manner." Disputes can happen and any complete agreement states that the parties will first make a good faith effort and provide what happens if that does not work. The MADRI Procedures do include specific useful procedures in comments by the Solar Energy Industries Association and others, but these are not included in the MADRI Procedures themselves.

NNEC Grading of the IREC Procedures

As noted, the NNEC concurs with IREC's view about what constitutes best practices on most points, and IREC assisted NNEC with its development of *Freeing the Grid* (2008). Thus, the fact that the IREC Procedures receive an "A" grade under the NNEC criteria is not surprising. In the end, it is up to regulators to determine whether the NNEC criteria are appropriately conceived and weighted. While the IREC Procedures would almost certainly allow greater penetration of distributed generation than other procedures, without loss of reliability or safety, some argue that the procedures shift costs from interconnection customers to ratepayers. While IREC debates that point, cost allotment is not settled.

Shortened timelines mean that utilities have to plan to have available engineering staff to meet the demand to review applications that arrive in any given week. Low application fees mean that utilities will not recover completely for installation types it is reviewing for the first time. Fixed engineering rates may not be sufficient in future years. Not requiring insurance entails a minute risk that the utility will suffer damages and not be compensated. And more systems means less utility sales, spreading fixed costs over fewer kW hours. On all of these points, the IREC Procedures are awarded a high score, and IREC argues that this is justified by the benefits of distributed generation.

The benefits of distributed generation include environmental benefits of renewable energy and efficient fuel use of combined heat and power systems, lowering of utility

peak demand and delay of the need for transmission and distribution system upgrades, and reduced rates for those customers who installed systems. It is up to regulators to set the balance between these benefits to ratepayers and the costs that they might incur due to reduced electricity sales.

On technical issues, the IREC Procedures receive points for what some might say are relaxed standards. Not requiring an external disconnect switch and allowing up to 500 kW on a typical area or spot network are examples. IREC counters that these positions do not entail any loss of safety or reliability based on the unlikelihood of anything going wrong using those criteria, especially given that no utility appears to have ever suffered damages anywhere in the country. Still, regulators continue to face the assertion that relaxing these provisions results in greater risk, and there is no adequate way to prove that the risk is very low.

Finally, IREC adopts a dispute resolution process that earns it credit under NNEC grading for putting binding authority regarding technical disputes in the hands of a technical master, if the utility's regulators have approved the technical master. This seems appropriate for small matters that do not justify resolution through arbitration or court. However, for very large systems, the amount in dispute could be sizeable.

Table 2. Grading of Interconnection Procedures

Criterion	NNEC Maximum	SGIP/ SGIA	CA Rule 21	MADRI	IREC
1. Eligible Technologies	0	0	0	0	0
2. Individual System Capacity	0	0	0	-0.5	-0.5
3. Breakpoints	2	0	-1	0	2
4. Timelines	1	0	0	-1	1
5. Interconnection Charges	2	0	2	-1	1
6. Engineering Charges	1	0	1	0	1
7. External Disconnect Switch	1	0	0	-1	1
8. Certification	1	0	1	0	0
9. FERC Technical Screens	1	0	-1	1	1
10. Spot Networks	2	0	0	0	2
11. Area Networks	2	0	0	0	2
12. Standard Form Agreement	2	0	0	0	1
13. Insurance	1	0	1	1	1
14. Dispute Resolution	2	0	0	0	2
15. Rule Coverage	1	0	0	0	0
16. Miscellaneous	0	0	-1	0	0
Score (with 7.5 pts added)*	**26.5**	**7.5**	**9.5**	**6**	**22.0**
Grade	**A**	**C**	**B**	**C**	**A**

* *NNEC adds 7.5 pts to each state's interconnection score in order to bring the point range for interconnection scores in line with the scores assigned to net metering rules, which NNEC also grades.*

Recommendations

The authors' primary recommendation is that utility regulators use a familiar starting point for the development of interconnection rules. Any of the four procedures discussed here can serve as a suitable starting point, although the authors favor the IREC Procedures. The procedures considered here have been extensively vetted and field tested, while unique procedures are likely to have unanticipated pitfalls. More importantly, the procedures reviewed here all contain key features that are critical for any successful interconnection rules. These features include broad applicability, capacity limits of at least 10 MW, breakpoints, standard form agreements, and limited insurance requirements.

As regulators develop rules starting from a selected standard, each NNEC criterion should be considered and regulators should either adjust the standard they are using to maximize the NNEC score or articulate why they are choosing an alternative approach. With respect to safety and reliability issues, regulators should consider that the SGIP/SGIA, CA Rule 21, and the MADRI Procedures were developed before most of the existing solar facilities in the United States had been installed. The caution in those procedures with respect to network interconnections, disconnect switches, and non-exporting generators are almost certainly overstated. The dispute resolution procedures in those procedures should be updated as well, to reflect the need for a technical master to address technical issues promptly.

With respect to criterion related to cost causation, regulators should consider whether or not there are offsetting benefits that justify applying a particular cost to ratepayers generally. In the zeal to properly account for cost causation, regulators can inadvertently create a significant impediment to interconnection of distributed generation at all. Utility costs to review the earliest applicants will be much higher than average review costs as thousands of generators come on line. Forcing the earliest applicants to bear all of the utility review costs will deter some, if not many, of those early applicants. Given the various benefits of distributed generation, the very small cost per ratepayer to set up utility programs is properly attributable to ratepayers generally.

Finally, beyond the NNEC criteria, the authors recommend that regulators strive to achieve the somewhat conflicting goals of simplicity and comprehensiveness. All else being equal, short rules are better than long rules, self-contained rules are better than rules spread over multiple documents, fixed timelines are better than targets, and penalties for utility non-compliance are better than no penalties.

To summarize, distributed generation is far more likely to be deployed if developers and utility customers can easily discern what the costs of interconnection are and how long the approval process will take. While regulators have a challenging task in formulating interconnection procedures, the benefits of implementing functional procedures are substantial.

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Practical, Legal, and Technical Reasons to Eliminate the Requirement

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September 2008

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Executive Summary

Some states and utilities require that a utility external disconnect switch (UEDS) be installed between a photovoltaic (PV) power system and the utility grid as a device necessary for safety. Adding the UEDS provides a utility worker with an additional means of disconnecting a customer's system.

However, thousands of PV systems in many jurisdictions have been connected to the utility grid both safely and effectively without a UEDS. Indeed, there is increasing evidence that UEDSs are seldom, if ever, used. The history of safety recorded from these jurisdictions demonstrates that when PV hardware meeting Underwriters Laboratories (UL) and Institute of Electrical and Electronic Engineers (IEEE) standards is installed in compliance with the *National Electrical Code® (NEC)* and operated according to procedures mandated by OSHA and in accordance with recognized Best Practices, the UEDS is not needed to ensure safe operation of a PV system. In fact, for properly designed and installed Code-compliant PV systems, the UEDS provides little, if any, additional safety, beyond what is already present. Indeed, utilities increase their risk of liability when they require the UEDS for safety during maintenance or emergency.

Currently, eight states—Arkansas, Delaware, Florida, Nevada, New Jersey, New Hampshire, North Carolina, and Utah—have incorporated provisions into their interconnection procedures that appear to waive the requirement for a UEDS for small, inverter-based systems. Although the precise application of these provisions may be subject to debate, it is clear that an increasing number of states have decided to do away with the requirement for a UEDS for small, inverter-based systems. In addition, many utilities around the country have also eliminated the requirement for the UEDS on systems less than 10 kW. This list of utilities includes Pacific Gas and Electric and Sacramento Municipal Utility District (SMUD) in California and National Grid USA in the northeast United States. Importantly, more than half of all small, inverter-based photovoltaic systems installed in 2007 were in these jurisdictions with no UEDS requirement.

This report documents the safe operation of PV systems without UEDSs in several large jurisdictions and explains why, increasingly, the Best Practice is to eliminate the UEDS requirement. As described in this report, the UEDS fails to provide the "fail safe" protection that is its justification, is functionally redundant to the traditional practice of "pulling the meter," and adds unnecessary cost to a PV system. This report recommends adherence to established Best Practices for PV system interconnection because they provide safety without the UEDS or its unfavorable impacts.

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Interstate Renewable Energy Council Web site:

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Solar America Board for Codes and Standards

The Solar America Board for Codes and Standards (Solar ABCs) is a collaborative effort among experts to formally gather and prioritize input from the broad spectrum of solar photovoltaic stakeholders including policy makers, manufacturers, installers, and consumers resulting in coordinated recommendations to codes and standards making bodies for existing and new solar technologies. The U.S. Department of Energy funds Solar ABCs as part of its commitment to facilitate widespread adoption of safe, reliable, and cost-effective solar technologies.

For more information, visit the Solar ABCs Web site:

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Acknowledgements

The author wishes to thank Gary Nakarado, J.D. of Regulatory Logic LLC for his critical review.

This material is based upon work supported by the Department of Energy under Award Number DE-FC36-07GO17034.

Table of Contents

Disclaimer ii

Executive Summary iii

Author Biography iv

Table of Contents v

Introduction 1

- What is a Utility External Disconnect Switch? 1
- Historical Background on Distributed Generation 1
- Current Status of the Utility External Disconnect Switch Requirements 2

Review of Literature, Standards, and Operations 2

- Safety, OSHA, and ANSI 2
- *National Electrical Code* Requirements 3

UL 1741 and Product Safety Evaluations 4

- Safety of Inverter Based System Subject to UL Testing Under IEEE Standards 1547-2003 4
- Traditional Utility Protection Practices Not Evaluated as Rigorously as Inverter Based Interconnection 4
- IEEE Standard Isolation Device Requirement 5

Operational Issues 5

- Non-Use of the Utility Accessible Switch 5
- Cost 6
- Legal and Jurisdictional Issues 6

Conclusions 7

Recommendation 7

References 8

Acronyms 9

Glossary of Terms 9

Introduction

What is a Utility External Disconnect Switch?

Photovoltaic (PV) systems are designed to operate as electric power generators, connected in parallel with the utility grid, and to meet stringent equipment and interconnection standards. A utility-interactive inverter serves as the interface for the PV system providing voltage and frequency synchronization and serving as the system controller. The inverter converts the DC power produced by the PV array into AC power in harmony with the voltage and power quality requirements of the utility grid. This harmonious voltage and frequency synchronization requires the existence of the utility AC power as a reference signal. The grid-interactive inverters are designed to shut down in the absence of utility power.

In the United States, the *National Electric Code® (NEC*) and authorities having jurisdiction (AHJ) require that grid-interactive PV inverters meet the safety and operational requirements of Underwriters Laboratories (UL) standard 1741[1] in addition to the interconnection requirements of Institute of Electrical and Electronic Engineers (IEEE) standard 1547-2003[2]. These standards describe the safety, system protection, and power quality requirements that the inverter must meet. As noted above, these standards also specify operational requirements for safe operation when the inverter is connected to the grid. UL 1741 test standard evaluates inverters for compliance with the IEEE 1547 interconnection requirements to automatically prevent the PV source from supplying power to the grid when the utility grid is not energized.

A Utility External Disconnect Switch (UEDS) is a disconnect device that the utility uses to isolate a PV system to prevent it from accidentally sending power to the utility grid during routine or emergency maintenance. The UEDS is installed in an accessible location for operation by utility personnel. Figure 1 shows the UEDS in a typical installation. However, meter locations on buildings vary, depending upon local zoning law and utility practices, and line workers seeking to disconnect PV systems in an emergency, may find it difficult to locate the meter and the UEDS. For example, they could be mounted on a wall behind bushes or other obstructions. Also, emergencies often occur during inclement weather or at night.

Figure 1: Typical location of Utility External Disconnect Switch, marked with a yellow caution label, below the production meter. The revenue meter is to left.

Historical Background on Distributed Generation

Utilities have historically treated customer-sited generation equipment connected to the grid with similar scrutiny as their large central power plants. Since there is a wide variety of generator types and installations, this common approach may cause excessive interconnection requirements for small, inverter-based generating systems. Central power plants are synchronous generators that export large amounts of power on high-voltage transmission lines. In contrast, small renewable energy systems are inverter-based sources that connect relatively small generators of power to the low-voltage side of the distribution transformer. Some utilities require distributed resources to provide direct-transfer trip, Supervisory Control And Data Acquisition (SCADA), and redundant relay protection devices such as those used by central power plants. Over the past decade, standards and codes have been updated to facilitate the safe operation of small distributed energy systems. Inverters and other equipment meet these newer standards. Many utilities now have different rules and procedures for small distributed systems than they have for central power plants.

1 UL 1741(2005) Inverters, Controllers, and Interconnection System Equipment for Use with Distributed Energy Resources

2 IEEE 1547 (2003), IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems

Current Status of the Utility External Disconnect Switch Requirements

Several utilities (such as National Grid[3], Pacific Gas and Electric[4] (PG&E) and Sacramento Municipal Utility District[5] (SMUD)) and eight states (Arkansas, Delaware, Florida, Nevada, New Jersey, New Hampshire, North Carolina, and Utah)[6] have waived the requirement for a UEDS for small, inverter-based systems. Increasingly, utilities such as PG&E and SMUD are taking advantage of self-contained meters as the means for facilitating the desired accessible/visible break/lockable functions without requiring a UEDS. As a result, more than half of all photovoltaic installations in the US in 2007 were installed without a UEDS[7].

Utility testimony indicates that, for properly designed and installed Code-compliant PV systems, the UEDS provides little, if any, additional safety, when a self-contained meter is already present[8]. There remain state and utility interconnection rules and guidelines that still require an accessible, lockable, visible-break safety-disconnect switch (for example[9,10]). Some utility companies are reluctant to accept the growing body of evidence that this additional safety device is unnecessary.

Review of Literature, Standards, and Operations

Safety, OSHA, and ANSI

Safety, in all aspects of PV system installation, interconnection, and operation, is of paramount concern to the Solar ABCs and the continued growth of connecting renewable energy sources to the grid. The Occupation Safety and Health Administration (OSHA) provides the law of the land for electrical safety regulations although utilities may interpret this law in various ways. The OSHA Act of 1970 requires employers to provide employees with a workplace free from recognized hazards known to cause serious physical harm. Sub part S of OSHA 29CFR part 1910, "Standards for General Industry," contains requirements that deal with protection from electrical hazards. Switching and tagging, and lockout/tagout are the primary methods of hazardous energy control. OSHA rules direct utilities to follow three general steps in switching and tagging procedures: first, check to be sure the circuit is dead; second, ground the circuit conductors; and third, work with gloves.

OSHA 1910.269 and provisions of 1910.331 through 1910.335 cover electrical safety work practices. As part of the three-step process to lockout/tagout a line section, OSHA Section 1910.333(b)(2)(iv)(B) states that:

A qualified person shall use test equipment to test the circuit elements and electrical parts of equipment to which employees will be exposed and shall verify that the circuit elements and equipment parts are de-energized. The test shall also determine if any energized condition exists as a result of inadvertently induced voltage or unrelated voltage backfeed, even though specific parts of the circuit have been de-energized and presumed to be safe. If the circuit to be tested is over 600 volts, nominal, the test equipment shall be checked for proper operation immediately after this test.

3 John J. Bzura PhD. email correspondence. *M.D.T.E. No. 1116-A Canceling M.D.T.E. No. 1088 Effective: April 2, 2007*. February 2008.

4 Pacific Gas and Electric Company. (Nov 2006). AC disconnect switches for inverter-based generation. Retrieved June 12, 2008 from http://www.pge.com/b2b/newgenerator/solarwindgenerators/disconnectswitches

5 "SMUD Waives Switch Requirement for Solar Systems: Move Makes Solar Installations Easier." SMUD, Feb. 21, 2007. http://www.smud.org/news/releases/07archive/02_21solar.pdf

6 Coddington, M.H., Margolis, R.M., & Aabakken, J. (2008). *Utility-interconnected photovoltaic systems: Evaluating the rationale for the utility-accessible external disconnect switch* page 23

7 Larry Sherwood, IREC personal communication July 6, 2008.

8 Public Service of Colorado testimony in Docket 07R-166E that its policy provides field personnel of either pulling the meter or utilizing the EUDS if they choose to disconnect a customer's system page 88

9 Ohio PUCo. Technical Requirement and Parallel Operation of Distributed Generation. page 1.4.2.

10 Exelon Energy Delivery Interonnection Guideslines for Generators 2 MVA or Less.Original: October 31, 2006. Page 8.

In contrast, utility standards for lockout/tagout usually reference the older, less rigorous American National Standards Institute (ANSI) standard Z244.1-2003 procedures. Where OSHA requires that a circuit be measured and verified as de-energized from all sources before servicing, the ANSI standard does not require this. The lack of a requirement to manually check for safe conditions has often been cited as the necessity for an accessible, lockable UEDS. However, OSHA procedures explicitly require the line section to be verified as de-energized prior to all service actions[11].

It is important to note that all grid interactive inverters installed in the U. S. have been tested to the UL 1741 and IEEE 1547 standards (explained below) that include passing the Unintentional Islanding Test, which verifies that the inverter does not operate independent of the utility. This evaluation also tests that these inverters cease to export power when the utility is de-energized.

Since the OSHA procedure must be performed *before* starting any maintenance or emergency work, a line determined to be de-energized and made safe via the OSHA safety procedures by a worker can not become energized by a grid-interactive inverter under any circumstances without reapplication of line voltage from the utility. Hence, since workers must determine that a line is de-energized and attach equipotential grounding before servicing, presence of the UEDS provides little additional protection for line workers.

National Electrical Code Requirements

The *National Electrical Code® (NEC)* requires all buildings or structures to have switches or breakers capable of disconnecting them from all sources of power[12]. The switches must be manually operable without exposing the operator to contact with live parts and must be readily accessible[13]. *NEC* 690.13 states: "Means shall be provided to disconnect all current-carrying conductors of a photovoltaic power source from all other conductors in a building or other structure." In addition, the switches must be permanently marked to identify them as PV system disconnects. In the case of solar generators, the *NEC* requires at least two manual disconnects on the inverter (one AC disconnect switch and one DC disconnect switch). In section 690.64, the *NEC* specifies that PV system inverters must have means for disconnecting AC, either with breakers in distribution panels or fusible switches. The *NEC* does not require that these disconnects be lockable or that they provide a visible-break separation, conditions placed on the UEDS.

More significant is the difference between the *NEC* and the utility in their working definition of the term "readily accessible." From the *NEC* perspective, a circuit breaker panel in the laundry room in a residence is readily accessible to the electrician who would come to repair a PV system (or general house wiring, electric range, etc.). So is the disconnect switch next to the inverter inside of the garage. If the house is locked and no one is home, then the electrician can't get to the breaker or the disconnect—or the inverter—and therefore can't work on the PV system, wiring, range, etc.

Utilities have a different perspective on *readily accessible*—their stated use of the utility disconnect would potentially require emergency access 24 hours a day, 7 days a week. It cannot be locked in a garage or laundry room. Since the utility usually has access to the customer's revenue meter, they typically want or require the PV utility disconnect switch to be located near the meter. Even though the meter may be located inside the house or building (in an area where the utility has 24-hour access), utility accessible locations are usually (though not always) on the building exterior, leading to the PV industry misnomer, *External* Disconnect Switch, rather than the more correct, Utility Accessible Switch designation.

11 OSHA standard interpretations: Recognition of ANSI ASSE Z244.1-2003 "Control of hazardous energy-lockout tag-out and alternative methods" consensus standard. Washington, D.C.: Occupational Safety & Health Administration.

12 National Fire Protection Association, *National Electrical Code (NEC)* 2008 section 690.13

13 ibid section 690.17 (1)

While in some cases the meter location may be a convenient point to connect the PV system—and thus a single switch could serve *NEC* and utility needs—in many cases it can be complicated and expensive to route. At times, it can be difficult to route PV output wires from a location that is both convenient and acceptable under *NEC* requirements (such as inside a garage) to a point acceptable to utilities. Meter locations on buildings vary depending upon local zoning law and utility practices, and line workers seeking to disconnect PV systems in an emergency may find it difficult to locate the meter and the UEDS. For example, they could be mounted on a wall behind bushes or other obstructions. Also emergencies often occur during inclement weather or at night. In those many cases where the *NEC* disconnect located near the inverter does not meet the utility's needs for readily accessible, the UEDS represents a redundant means to disconnect the system from the grid. In addition, this additional wire and equipment also contributes to system losses and potential maintenance concerns.

UL 1741 and Product Safety Evaluations

Safety of Inverter based system Subject to UL Testing under IEEE Standards 1547

The UL 1741 standard covers inverters, multi-mode inverters, converters, controllers, and interconnection systems for use with Distributed Energy Resources (DER). UL 1741 combines product safety requirements with the interconnection system test requirements developed in the IEEE 1547 standard to delineate the specific procedures and criteria for evaluating and certifying distributed generation products. UL 1741 goes beyond IEEE 1547 requirements to include product safety aspects. Rigorous tests must be passed for any inverter to obtain UL 1741 listing.

IEEE 1547 and IEEE 1547.1 were written to become the basis for DER interconnection of 60 Hz systems (i.e., North America voltage and frequency) and were based upon existing criteria for evaluating utility interconnection relays, and upon utility interconnection certification requirements from individual state and local public utility commissions (PUCs). Relays perform the protective functions that are integrated into an inverter. UL 1741 was revised in 2005 to directly reference the IEEE 1547 requirements and IEEE 1547.1 test procedures. IEEE 1547 references IEEE C37.90 and IEEE C62.41, standards that are normally applied to "utility grade" protection relays.

The combination of the UL 1741 and IEEE 1547 standards help to harmonize the utility interconnection requirements and equipment conformance validation across the United States. The IEEE 1547-compliant UL 1741 requirements became effective on May 5, 2007. Underwriters Laboratories Inc. and other Nationally Recognized Testing Laboratories (NRTLs) perform quarterly unannounced manufacturing inspections on the UL 1741 Listed equipment to verify that products continue to be produced in the same manner as when they were originally evaluated and tested. This process is intended to prevent variations in the critical components (hardware and software) that could affect the critical utility interconnection performance of the product.

Traditional Utility Protection Practices Not Evaluated as Rigorously as Inverter Based Interconnection

Unfortunately, utilities have not required that interconnection protection relays be Listed to UL 1741. Utility protection equipment is only required to meet the IEEE 1547.1 testing requirements and lacks the additional safety afforded by product testing and oversight of critical hardware and software that a NRTL listing provides.

PV system inverters today are UL 1741 Listed with anti-islanding feature. Islanding is a situation in which a portion of the electrical grid that contains loads and generation source remains energized even after it is isolated from the remainder of the electrical

grid. The traditional utility concern is that the islanded system will suddenly and unexpectedly connect to the grid and re-energize it—or remain energized when the utility believes the portion of the grid in question to be completely de-energized. To be UL 1741 Listed, inverters must pass tests to "successfully demonstrate that their anti-islanding protection methods operate in less than two seconds under a range of conditions expected on the feeder[14]."

There are distributed generation systems designed to operate site loads during utility outages. However, these are for service institutions such as hospitals and other sites that have stand-by generation that is energized during a utility outage. All of these systems have specially designed power transfer systems that prevent the system from energizing the utility grid during an outage.

IEEE Standard Isolation Device Requirement

Some utilities cite the IEEE Standard 1547 Isolation Device clause 4.1.7 as justification for the UEDS[15]. Clause 4.1.7 in IEEE-2003 states: "When required by the Area Electric Power System (EPS) operating practices, a readily accessible, lockable, visible-break isolation device shall be located between the Area EPS and the DER unit." In other words, under IEEE 1547, an isolation device is not a universal requirement, but IEEE 1547 recognizes that utilities could require a redundant disconnect that could be on the utility side of the meter in addition to the many utility methods already available to isolate a circuit. Unless the local jurisdiction rules otherwise, this isolation device clause in IEEE 1547 is not a mandatory equipment requirement.

Operational Issues

Non-Use of the UEDS

Where the UEDS is required for renewable energy systems, discussions with utility personnel show that few utilities have used the switch during maintenance or emergency situations. One research project found that none of the external disconnect switches studied had been used by utility maintenance staff[16].

We will review some of the reasons why utility workers have not operated the UEDS for safety during either maintenance or emergency conditions. First, most residential PV systems are less than 10 kW. Residential customers have a potential connected load above 20 kW. Motor loads in particular tend to trip off isolated PV systems because motors have an in-rush current in the range of 5-12[17] times normal load. Typical motor loads are air conditioning units, washing machines, and refrigerators. If the grid is de-energized, then the PV alone cannot supply the motor load for the residence, and the inverter will shut off.

Second, according to Coddington et al.[18], on the UEDS a line worker can only be injured by a PV system if several failures occur at the same time. Similarly, the California Rule 21 Supplemental Review Guideline[19] states that a number of specific conditions must exist for unintentional islanding to take place. Public Service of Colorado's expert witness on this subject[20] has confirmed that a very unlikely series of events must occur to place a line worker at risk from a PV system installed without a UEDS.

14 Email and conference call with Tim Zgonena, Principal Engineer, Underwriters Laboratories, Inc.

15 Potomac Electric Power Company's Reply Comments Case No 1050,41 May 2,2008 Response to MD-DC-VA Solar Energy Industry Association page 6

16 U.S. Department of Energy, *Million Solar Roofs Case Study: Overcoming Net Metering and Interconnection Objections,* September 2005

17 How to Make Accurate Inrush Current Measurements Mar 1, 2003 , By Bob Greenberg, Fluke Corp

18 ibid Coddington page 11

19 www.energy.ca.gov/distgen/interconnection/SUP_REV_GUIDELINE_20050831.PDF Section 7.1 5a-c

20 Public Utilities Commission State of Colorado Docket 07A-462E Volume 4 page 102

Third, operation of multiple UEDSs is onerous for the utility. Utility companies may be reluctant to follow the number of steps necessary to document the required information necessary to properly switch and tag each PV system. This includes recording the location and size of each PV system on the utility's circuit maps and making this information available to system operators, engineers, line workers, and all non-utility employee crews working on the utility facilities. This is simply not practical in utility operations. In order to do this, information with details of the interconnect agreement must be communicated from the commercial side to the operational side of the utility. In addition, if the UEDS is to be operated for safety during maintenance and emergency situations, then the appropriate switching orders need to be generated for each work group, and all switching and tagging orders for small PV systems need to be posted and incorporated into existing switching and tag-out orders. Finally, although the utility must ensure access to the UEDS just as it does for all metering, utility metering personnel and service personnel are not the same. Service outages on the distribution system come at night or in bad weather conditions when metering personnel are not available to help with locating a UEDS. Thus, some utilities allow the practice of "pulling the meter" to isolate the system[21,22] if the need for isolation is found to be necessary.

Cost

Several PV installers have estimated the typical incremental cost of installing a UEDS to be in the range of $200 to $400. In response to a question from the Florida Public Utilities Commission, Progress Energy estimated the cost of the UEDS to be $1,253.13 per customer[23]. Whether the lesser or the higher estimate, on small systems, the UEDS is a burden that will have long-term impacts with no clear benefits. The national interest requires that our renewable energy installations be completed in as cost effective a manner as possible, consistent with Best Practices including safety concerns.

Legal and Jurisdictional Issues

There are two legal issues that arise from the utilities' claim that the UEDS is necessary for safety. The first issue is the exposure that utilities accept when they "require" the UEDS and then fail to operate it during maintenance or emergency situations. A utility that fails to incorporate the use of the UEDS into its standard operating procedures could as a result be faced with the prospect of additional source of liability or even punitive damages in case of injury[24].

The second issue arises from the fact that the utility requires the line worker to operate the UEDS even though it is located outside the utility's jurisdiction, i.e., it is not utility property and is located on the customer side of the meter. The legal concern arises because utility line workers are considered not "qualified"[25] under *NEC* requirements to work outside the utility's jurisdiction. The utility is exposed to liability if the line worker becomes injured attempting to operate the UEDS.

21 Pacific Gas and Electric Company. (Nov 2006). AC disconnect switches for inverter-based generation. Retrieved June 12, 2008 from http://www.pge.com/b2b/newgenerator/solarwindgenerators/disconnectswitches/

22 Transcript of cross examination of Public Service of Colorado expert witness on this subject in 2008 Public Utility Commission of Colorado Docket 07R-166E page 88

23 Florida Public Utilities Commission (2007). Docket 070674-EI. Tallahassee, FL.

24 ibid Cook

25 National Fire Protection Association. (2007). Report on proposals A2007 NFPA 70. Quincy, MA:

Conclusions

This report highlights how a number of progressive state regulatory commissions and utilities with jurisdiction over a large portion of the country's inverter-based renewable energy systems have eliminated the UEDS requirement traditionally required for interconnection of Distributed Energy Resource generation and how the growing evidence indicates that the UEDS requirement can be eliminated from state and utility requirements for PV systems without compromising the safety of these systems or of personnel working near them.

The disadvantages of the UEDS requirement are:

- The lack of any measurable benefit to safety
- The additional cost of UEDS
- The potentially detrimental impact on PV system losses and reliability
- The possible liability incurred to federal sanctions and penalties as well as to punitive damages.

Furthermore,

- Utilities rarely, if ever, use the installed UEDS
- PV systems installed without a UEDS have had a clean safety record
- More than half of the small PV systems installed in 2007 did not have a UEDS
- A growing number of utility and regulatory commissions have decided to eliminate the UEDS requirement.

Recommendation

The recommendation is to eliminate the requirement for UEDS for all small, inverter-based systems in all jurisdictions. With the inherent safety features built into all UL-listed PV inverters, the UEDS is functionally unnecessary and provides little, if any, additional safety.

For customers with self-contained meters (including almost all residential and small commercial customers), the meter itself is already fully capable of providing the functions required of the switch (i.e., a visible, physical, lockable separation of the system from the utility). At the very minimum, these customers should be excluded from any UEDS requirement.

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Acronyms

AC	Alternating current
ANSI	American National Standard Institute
AHJ	Authorities Having Jurisdiction
DC	Direct current
DOE	Department of Energy
DER	Distributed Energy Resource
EPS	Electric Power Systems
FERC	Federal Energy Regulatory Commission
IEEE	The Institute of Electrical and Electronic Engineers
IREC	Interstate Renewable Energy Council
NEC	*National Electrical Code®*
NFPA	National Fire Protection Association
NREL	National Renewable Energy Laboratory
NRTLs	Nationally Recognized Testing Laboratories
OSHA	Occupational Safety Health Administration
PG&E	Pacific Gas & Electric
PV	Photovoltaic
SMUD	Sacramento Municipal Utility District
Solar ABCs	Solar America Board for Codes and Standards
UL	Underwriters Laboratories
UEDS	Utility External Disconnect Switch

Glossary of Terms

Best Practice: A technique or methodology that, through experience and research, has proven to reliably lead to a desired result. A commitment to using the Best Practices in any field is a commitment to using all of the knowledge and technology at one's disposal to ensure success.

De-energized: Free from any electrical connection to a source of potential difference and from electrical charge; not having a potential different from that of the Earth.

Intentional Islanding: Intentional islanding is the purposeful sectionalization of the utility system during widespread disturbances to create power "islands." These islands are designed to maintain a continuous supply of power during disturbances of the main distribution system.

Self-Contained Meter: A utility revenue meter that contains all sensing elements within the casing and meter base connections. All power to the facility must pass directly through the meter in order for the facility to receive service. Should the meter be removed, a physical separation will occur between the meter-base blade sockets, and the facility will be isolated from the utility. Nearly all residential customers are served by self-contained meters.

Unintentional Islanding: An unplanned condition where one or more DERs and a portion of the electric utility grid accidentally remain energized through the point of interconnection.

Utility External Disconnect Switch: An isolation device, accessible to utility personnel, used to provide a physical separation between a customer-generator and the utility system. This device must have a visibly-verifiable separation, be lockable in the open position, but does not need to be load-break rated or even be a switch.

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Potential Impacts of Advanced Metering Infrastructure on Renewable Energy Policy

A Solar ABCs White Paper

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April 2010

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Executive Summary

Advanced Metering Infrastructure (AMI) allows bidirectional communication between the utility and the customer. This allows the utility to gain rapid feedback on the condition of and events occurring on its electric grid and the opportunity to assert controls over load-side parameters.
This white paper is a primer that gives the reader an overview of AMI and identifies possible impacts on renewable energy policy and the integration of renewable energy generation into the electric utility grid.

Key Findings

Renewable and distributed generation will be integral parts of the future grid. As AMI is adopted, regulator decisions on AMI adoption will impact renewable energy policy and utility integration. The following list presents some of the areas that will be most affected.

Utility Rate Structure

AMI has the potential to bring time-of-use and real time pricing to the mass-market and, in many cases, to provide utilities with a strong business case for doing so. Renewable energy advocates must educate themselves about the proposed rates to ensure that they do not adversely affect the market for solar PV or other renewable technologies.

Incentives

The meter data management system must be able to incorporate the calculation of both the net energy generation and incentives, and communicate these derivations to the customer. Additionally, the speed of detection and response of all communications must be assessed and made compatible with other levels of communications. It is likely that some utilities will not consider these issues on their own and could resist incorporating these calculations into an AMI project because the additional costs do not appear to have a benefit for operation. However, as more renewable energy is integrated into the electric grid, these features will be needed and may force a later and costly modification to any existing AMI application.

Data

AMI technologies will often allow access to real-time data about the conditions of the utility grid as well as the manner in which individual consumers use electricity. These data will be valuable to many parties, but customer privacy must be observed. Utilities may be reluctant to share the information. One solution that has been used is that regulators not allow utilities to have control of the data; instead, third-party vendors should be engaged to manage the data and assure neutrality.

Interconnection

The control functionality and the capabilities of AMI may reduce the barriers to interconnection of distributed renewable energy technologies. For example, the current practice of limiting distributed generation (DG) penetration to 10 % of local distribution rating may be eased as the utilities can be assured of knowing the conditions on its grid at all times and of controlling DG device interaction. Thus, AMI technologies may allow greater penetration of distributed generation and reduce the barriers to interconnection.

Engaging Policy Makers

As AMI projects are designed, it is likely that their implementation may affect current policies. Due consideration to the impact of any plan that may restrict existing, successful policies should be given to ensure that the recognized societal benefits are maintained.

Standardization of AMI Requirements

Those reviewing any plans for the implementation of AMI projects must consider the ability of the proposed technology to communicate with other technologies. The renewable energy community should be aware of new standards and ensure that devices such as inverters meet the standards necessary to be integrated into the future grid.

Work with Utilities

The renewable energy community should seek out opportunities to work with electric utilities and technology manufacturers. Many of the existing business models governing investor-owned utilities would need revision under the new paradigm that adoption of AMI will introduce. These new paradigms offer an opportunity for the renewable energy community to have input into new methods of transacting business in the energy sector.

Author Biography

Keith McAllister is currently the Program Manager for Clean Energy Applications at the North Carolina Solar Center at North Carolina State University. He is also the Director of the US DOE's Southeast Clean Energy Application Center and a member of the Solar ABCs Steering Committee. In these roles, Mr. McAllister continues to investigate technology and policy initiatives that increase the efficient use of energy. Mr. McAllister has also investigated novel concepts for the electric grid such as micro-grids and advanced metering infrastructure. As an engineer in the research section of Progress Energy (formerly known as Carolina Power & Light Company) Mr. McAllister worked on programs in the areas of Thermal Energy Storage, air-source and ground-source heat pumps, building envelope improvement, lighting, distributed generation, and industrial energy efficiency. This experience has given him a broad knowledge of both the electric utility's and end user's perspective on energy use, energy reliability and security and energy efficiency. Mr. McAllister holds both a BS and MS in Mechanical Engineering from North Carolina State University and he is also a licensed professional engineer in the State of North Carolina.

IREC

Interstate Renewable Energy Council Web site:

www.irecusa.org

NORTH CAROLINA SOLAR CENTER

North Carolina Solar Center Web site:

www.ncsc.ncsu.edu

Solar America Board for Codes and Standards

The Solar America Board for Codes and Standards (Solar ABCs) is a collaborative effort among experts to formally gather and prioritize input from the broad spectrum of solar photovoltaic stakeholders including policy makers, manufacturers, installers, and consumers resulting in coordinated recommendations to codes and standards making bodies for existing and new solar technologies. The U.S. Department of Energy funds Solar ABCs as part of its commitment to facilitate wide-spread adoption of safe, reliable, and cost-effective solar technologies.

For more information, visit the Solar ABCs Web site:

www.solarabcs.org

Acknowledgement:

This material is based upon work supported by the Department of Energy under Award Number DE-FC36-07GO17034.

Keith McAllister and his staff would like to thank The Department for their support on this important project, Jason Keyes, Kevin Fox, and Mike Sheehan from IREC, Andy Rosenthal from NMSU, Larry Sherwood from Sherwood Associates, Mike Coddington and Tom Basso from the National Renewable Energy Laboratory, and Ward Bower from Sandia National Laboratory as well as the stakeholders who participated in the quarterly conference calls and the stakeholder meeting for their input to this document.

Table of Contents

Disclaimer ii

Executive Summary iii

Author Biography iv

Introduction 1

AMI & AMR Technologies 3

- Automated Meter Reading Technology 3
- Advanced Metering Infrastructure Technology 4

Issues for Renewable Energy 5

- Issue: Utility Rate Structure 5
- Issue: Incentives 5
- Issue: Data 6
- Issue: Interconnection 6
- Issue: Engaging Policy Makers 7
- Issue: Standardize AMI requirements. 7
- Issue: Work with Utilities 7

References 8

Suggested Further Reading 9

Nomenclature 10

Frequently Asked Questions 11

Introduction

Over the last two decades, groundbreaking changes have occurred within the electric utility industry: deregulation in certain regions, utility mergers and acquisitions, the convergence and subsequent divergence of the electric and natural gas industries, energy trading, organized electricity markets in the form of Regional Transmission Operators (RTOs) or Independent System Operators (ISOs), renewable portfolio standards, greenhouse gas (GHG) policies, and many others. The next groundbreaking change has begun (see Figures 1 & 2) and may be the most dramatic of all. The North American electric system has begun to transcend its historic, one-way supplier-to-buyer structure to move to a fully integrated digital network—a new paradigm called Advanced Metering Infrastructure (AMI) — in which suppliers and buyers may, in many cases, communicate using near real-time information to make choices regarding electricity supply and usage.

Figure 1: AMI, AMR & Smart Grid Projects as of November 2008 (Google maps 2008)

The American Recovery and Reinvestment Act of 2009 (ARRA), also known as the Stimulus Plan, has provided some funding for these and other initiatives. The ARRA provides $4.5 billion specifically for Smart Grid technologies; (Smart Grid News 2009) additionally, other portions of the ARRA contain language which could incorporate stimulus funding.

These include:

- New loan authority for Bonneville Power and Western Area Power Authority for transmission projects ($6.5B)
- Energy Efficiency and Conservation Block Grant ($3.2B)
- Transportation, including electric vehicles ($1.7B)
- Renewable energy loan guarantees ($6B)
- Research in energy efficiency, renewables, batteries and clean fossil energy ($8.4B)
- Broadband Technologies Opportunities Program ($7.2B)

Additionally, the DOE has increased capital funding for Smart Grid project grants from $20 million to $200 million. (Smart Grid News 2009) This funding, as well as the proven advantages of AMI technologies to significantly reduce utility operational costs and enable significant demand-side response (Duke Energy 2008), has led to a dramatic increase in the number of projects as shown in Figure 2.

Figure 2: AMI, AMR & Smart Grid Projects as of October 2009 (Google maps 2009)

As these projects are implemented, legislative and regulatory decisions are being made which will impact renewable energy policies.

This paper is a primer that gives the reader an overview of AMI and identifies possible impacts on renewable energy policy and the integration of renewable energy generation into the electric utility grid.

The first section provides a high level description of the technologies. Providing a detailed explanation of how AMI and its related technology Automatic Meter Reading (AMR) work is outside the scope of this document. Many other industry documents are publicly available for that purpose. For a more detailed knowledge of these technologies, please see the "Suggested Further Reading" section at the end of the paper.

The next section identifies some of the impacts on the following renewable energy issues:

- Rate structures
- Incentives
- Ownership of data
- Technical interconnection issues
- Engaging policy makers
- Standardize AMI requirements

The paper encourages policy makers and regulators to become educated on these and other potential impacts and to become engaged in the regulator process of AMI proceedings.

AMI & AMR Technologies

In order to understand the current environment which is fostering the explosive growth of AMI projects, one should understand the vision of the future electric transmission and distribution grid. In 2003 the United States Department of Energy's (DOE) Office of Electricity Delivery and Energy Reliability (OE) gathered 65 senior executives from electric utilities, equipment manufacturers, information technology providers, federal and state government agencies, interest groups, universities, and national laboratories. The mission of this group was to develop a national vision of the future electrical system with a focus on "the portion of the electric infrastructure that lies between the central power plant and the customer —as well as the regulatory framework that governs system planning and market operations." The result of that meeting was a vision document entitled "Grid 2030" – A National Vision for Electricity's Second 100 Years," (US DOE 2003) which has provided the framework for DOE's research, development and implementation of Smart Grid technologies which includes AMI and AMR.

On a national level, Congress began to recognize the potential benefits of smart grid technology several years ago. The Energy Independence and Security Act of 2007 (EISA 2007) Section 1301 establishes a federal policy to modernize the electric utility transmission and distribution system to maintain reliability and infrastructure protection. (EISA 2007) AMI refers to a distribution system that allows for flow of information from a customer's meter in two directions: both inside the house to thermostats, appliances, and other devices, and from the house back to the utility. Section 1307 directs the states to encourage utilities to employ AMI technology and allow utilities to recover AMI investments through rate structures. This could be in a rate rider form which could be charged on a kWh or a per dollar basis. However, utility commissions may allow a flat charge to be applied to the service and facility charges.

Through AMI, today's peaks and valleys of consumer demand may be smoothed as the industry's supply side becomes attuned to and is supplemented by information and input from the demand side (PJM 2007). The report draws the conclusion that from the perspective of the utility, accurate real-time or time-of-use pricing will drive demand-side behavior. Integrated distributed generation and demand response capabilities may support load leveling, allowing central plants to run at a higher capacity factor. The grid of the future will incorporate renewable energy, such as wind and solar, energy storage and management, photovoltaics, and deliver signals to consumer appliances which will modify their energy use characteristics.

The following sections give a very high level review of AMR and AMI technologies.

Automated Meter Reading Technology

AMR technology, often used to reduce metering reading costs, uses a solid-state meter (SSM) to automatically collect energy data from a customer's premise and transmit it to a centralized database, sometimes called a meter-data management system (MDMS), for billing and analysis. The information may be passed from the meter to the database in a variety of methods, including handheld scanners, transmission to personnel either walking or driving by, or over a variety of communications networks. Meters may simply capture energy usage data or may include features such as tamper detection, alarm conditions, or interval data. AMR automates the meter reading functions of the utility. There are many features available in these systems. The New York Public Service Commission identified a few of these features in a 2008 report.

AMR is expected to provide multiple benefits to the utility:

- elimination of manual meter reading,
- deferral of metering capital costs,
- increased revenue due to improved meter accuracy,
- reduction of off-cycle reads,
- fewer estimated bills,
- lower load research costs,
- reduction of revenue losses from unoccupied premises,
- reduction of field service orders,

- reduction of call center contacts for bill-related and power quality calls, and
- reduction of compensation/claims for manual meter reading accidents.

Future and societal benefits include decreased costs through use of remote reconnect/disconnect or load limiting devices, and the potential for more accurate cost allocation and rate design because of accurate hourly billing consumption data. (NYPSC 2008)

Advanced Metering Infrastructure Technology

AMI builds on the capability of AMR by adding more robust communications technologies, which allows the utility to communicate with the customer, the customer to communicate with the utility and, in many cases, allows the utility to gain rapid feedback on the condition of and events occurring on its utility grid.

An Advanced Metering Infrastructure (AMI) system typically utilizes an SSM, a Home Area Network (HAN), a communications system, a meter-data management system (MDMS), and a utility operating system (UOS) that makes use of the data provided by the other components of the system.

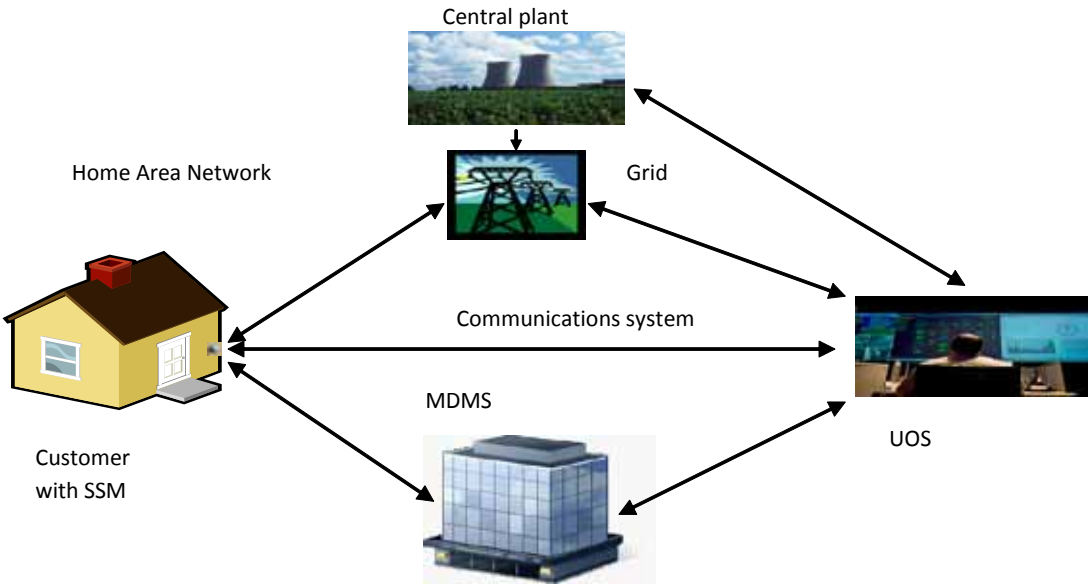

Figure 3: AMI System

In addition to the benefits gained from the AMR system, an AMI system offers reduction of costs to support other R&D initiatives by providing a low cost method of gathering data, reduction of false outage dispatches, reduction of nested-outage restoration time, reduction of long-term outage response time, increased customer participation in demand-response programs that may defer transmission and distribution system upgrades, decreased costs through use of remote reconnect/disconnect or load limiting devices, additional reduction of field service orders, possible increased customer utilization of eCommerce channels, avoided capacity costs due to increased load management participation, and the ability to meet increased demand from cutting edge technologies (NYPSC 2008).

Issues for Renewable Energy

AMI, and its component technology AMR, have begun a transformative revolution within the electric utility industry, as has been seen in other network-based industries such as the telecommunication industry. It is clear that AMI is and will continue to be a disruptive technology that replaces existing methods and systems. A lesson learned from the telecommunications and internet experiences shows that standardized architecture and techniques are required for the distributed intelligence and "smart" power systems, which will enable this revolution (USDOE 2003).The two-way communication features and distributed intelligence that are emerging in these technologies will change the way that electricity is generated, transmitted, and ultimately used. Renewable and Distributed generation are viewed to be integral parts of the future grid as it reaches its potential as seen by the DOE and others. As AMI is adopted, decisions are being made in the regulatory process which impact Renewable Energy Policy. While this list is not intended to be comprehensive, some of the areas which will most affect Renewable Energy Policy are briefly discussed below.

Issue: Utility Rate Structure

AMI has the potential to bring time-of-use (TOU) and real time (RTP) pricing to the mass-market and, in many cases, to provide utilities with a strong business case for doing so. In the past, TOU tariffs were often seen as overly complicated for both the utility and the customer. However, the two-way communication feature of AMI will allow pricing signals to be sent to the customer. These pricing signals may match rates to the actual cost of energy at a given time period. The utilization of these rate structures may allow one of the great potentials of AMI, the ability to reduce the peak demands in electrical energy usage, to be realized. Currently, the average capacity factor of central power plants is 55% (Pullins 2008). Thus, up to 45% of the capital dollars spent to build these facilities was necessary just to meet peaking requirements. While a small portion of this excess capacity can be attributed to the need for a reserve margin, even that need could be reduced or nearly eliminated once the full capabilities of an AMI enabled grid are realized. The pricing signals along with rate design are expected to modify customer behavior. Automation within the HAN will allow appliances to react to these signals without the need for customer intervention, but the customer may chose to have the ability to be notified a day in advance and make these decisions based on predicted costs. It is envisioned that modified customer behavior will serve to flatten demand curves. As peak demands are reduced the need for demand charges within tariffs may also be reduced. The two-way communication ability facilitates customer choice. Xcel Energy provides two potential examples through its pilot Smart Grid project in Boulder, CO (James 2008). Xcel expects to be able to offer customers a variety of rates from which to select. Consumers may desire a flat-rate, a TOU structure or a critical-pricing model. One novel initiative that has been discussed by Xcel would allow the consumer to set a price for their electricity purchase. The customer would choose from a low-cost option to a range of higher cost options which would include more Renewable Energy (RE) generation assets. In essence, consumers would have input into the dispatching decision making process (personal meeting with Xcel).

Renewable Energy advocates must educate themselves about the proposed rates to ensure that they do not adversely affect solar PV or other renewable technologies. For example, many net metering rates initially had Net Excess Generation (NEG) (IREC 2010) credits forfeited to the utility at the end of the calendar year. However, PV systems could build up more NEG credits during the summer than could be expended by the end of the year. Several jurisdictions have changed the "true-up" date to the spring of the new calendar year to alleviate this issue.

Issue: Incentives

The information gathering capability of AMI could have a dramatic impact on the way incentives are measured, especially for performance-based and time-of-use incentives, as well as a means of providing customers a simple way to understand the impact of these incentives. The Solar Alliance, alliance of solar manufacturers, integrators and financiers and a respected voice in the solar PV marketplace, states that a "commitment to analytical rigor and technical analysis is critical to demonstrate the effectiveness of a solar [incentive] program." (Solar Alliance 2008) These data can be easily captured by AMI systems. These data can be used to verify both the performance of systems and to provide documentation for successful systems that can be replicated.

An ability of a fully integrated AMI system is that utility sub-systems have the ability to communicate with one another. Distributed generation assets, such as PV, could be monitored in real time and the data could be

incorporated into the utilities billing systems which could reduce the costs of incentive programs while allowing access to data that could be used to evaluate incentive programs. (Connecticut DPUC 2008) Additionally, the information could be relayed to a HAN. If properly designed, the customer interface will allow an open, easily understood and transparent means of communicating the value of incentives to consumers.

Those interested in the development of RE must become part of the discussion of any AMI docket. The appropriate features of the AMI components must be included if the previously stated scenarios are to become reality. For example, the SSM must have the ability to distinguish the direction of power flow and to communicate with inverters. The HAN must have the ability to display the information in a clear and meaningful way. The MDMS must be able to incorporate the calculation of both the NEG and incentives and communicate these derivations to the customer. The speed of detection and response of all communications must be assessed and determined compatible with other levels of communications. It is likely the utilities will not even consider these issues on their own and are likely to resist incorporating additional costs for what are seen as a small portion of ratepayers. However, as more RE is integrated into the electric grid these features will be needed and would most likely force a costly modification to any existing AMI application. In the cases of states where munis and co-ops are not regulated by Utility Commissions, legislation may be necessary to ensure these issues are addressed.

Issue: Data

AMI technologies will often allow access to real-time data about the conditions of the utility grid as well as the manner in which individual consumers use electricity. It is clear that energy use and load information will be valuable to many entities. Manufacturers, integrators, billing aggregators, NGOs and many others will want access to these data, which will be invaluable in the development of innovation that will benefit all. For example, RE & Distributed Generation (DG) developers may use the data for target marketing purposes, equipment and appliance manufactures would want to know when consumers' products require maintenance or replacement, RE advocates would want access to real-time data in order to develop new policies and incentives, to name a few.

In this environment, it is essential to carefully define ownership rights for metering data; however, any policy that defines ownership rights and access to data must also give careful consideration to privacy rights and security risks. Rule makers must balance the benefits of making data available to entities outside of the electric utility while limiting potential issues related to privacy and security. One solution that has been used is that regulators not allow utilities to have control of the data; instead, third-party vendors should be engaged to manage the data and assure neutrality. (IESO 2007) Additionally, any regulations must also include language that will protect the utilities from liabilities associated with unauthorized use of these data. A utility must be held harmless, if they are complying with the regulations, in the event that personal information is stolen or otherwise misused.

Issue: Interconnection

The control functionality and the capabilities of new power electronics devices may reduce the barriers to interconnection of distributed renewable energy technologies. Traditionally, distribution engineers made calculations based on static conditions. Protection, with protection and coordination device settings derived based on one-way power flows. Now, with the ability to gather real-time data on grid operations, to communicate updated control settings to protection devices and control DG equipment, interconnection could become plug and play.(FREEDM 2009) Smart Grid and AMI have the ability to positively impact RE and DG technology by reducing the cost of interconnection studies, shortening the time to get interconnection approval, allowing larger systems to be integrated into the grid and facilitating different rules for different sized systems. (McGranahan 2008) The current practice of limiting DG penetration to 10% of local distribution rating could also be eliminated as the utilities can be assured of knowing the conditions on its grid at all times and controlling DG device interaction. Thus, these technologies may allow greater penetration of distributed generation and reduce the barriers to interconnection.

RE and DG technologies will play a crucial role in this new paradigm. These assets can be used to relieve congestion, potentially improve reliability, reduce restoration times, and help flatten load profiles on central plants. While the potential of RE and DG to achieve these impacts have been discussed for years, communication and control issues have limited the actual implementation of these capabilities. However, the widespread use of AMI may help enable the potential to become reality. RE advocates must educate themselves on the capabilities of AMI technologies and ensure that the features necessary to facilitate the integration of DG is included in a

utility's plan to integrate AMI onto their T&D grid.

Issue: Engaging Policy Makers

As seen in Figure 2, many electric utilities have deployed large numbers of AMR and / or AMI systems. As these plans go through the regulatory process, decisions are being made that will impact RE policy. The RE community must fully understand the potential of AMI to impact its industry. Once these policies are in place, they will become difficult to modify.

Existing RE policy benefits, such as Net Metering, Renewable Portfolio Standards, Public Benefit Funds, were designed to recognize the societal benefits of distributed RE, such as greenhouse gas reduction, resource diversification, renewable portfolio standard requirement compliance, and alleviation of demand in transmission-constrained load pockets. Current policies have been successful in approaching these objectives. As AMI projects are designed, it is likely that their implementation may affect current policies. Due consideration to the impact of any plan that may restrict existing, successful policies should be given to ensure that the recognized societal benefits are maintained. Existing RE policies should be examined with an eye on the disruptive capabilities of AMI and the RE policies may need to be revised to maximize the benefit to society.

Issue: Standardize AMI Requirements

The Grid 2030 document (USDOE 2003) concluded that standardization of protocols take place between the different technology components of AMI. A key feature of AMI is its ability to communicate. If devices are not able to communicate with each other due to proprietary designs, the ability of AMI to reach its full potential will be severely limited. Those reviewing any plans for the implementation of AMI projects must consider the ability of the proposed technology to communicate with other technologies. Several IEEE standards are being developed. In May 2009, the DOE announced that any projects receiving stimulus funding must comply with no less than 16 standards addressing such topics as cyber security, SSM's, and DG components (WSJ 2009) and the IEEE P2030 interoperability standards (IEEE 2009) began proceedings in 2009.

The RE community should be aware of these standards and ensure that devices such as inverters meet the standards necessary to be integrated into the future grid.

Issue: Work with Utilities

The RE community should seek out opportunities to work with electric utilities and technology manufacturers. AMI technologies will change the way we generate, distribute and utilize electricity. Many of the existing business models governing investor owned utilities are becoming outdated under the new paradigm that will develop. These new paradigms offer an opportunity for the RE community to have input into new methods of transacting business in the energy sector. The RE community has insight into the emerging technology that is early in its technology development cycle. The insight that this community brings will be valuable to regulators, policy makers, technology manufacturers and utilities. By working with utilities to address issues such as the depreciation of equipment, contracting issues related to the utilities obligation to serve when confronted with DG assets which they do not own, and intelligent tariff / rate and incentive designs which drive behavior, the RE community can gain a valuable negotiating position to push issues that are important to its goals. Becoming educated on the issues and the capabilities of the technologies, as well as comprehending the potential impact of today's decisions on future policy goals could enhance the many of the gains made over the last thirty years and provide new opportunities for the RE community.

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Nomenclature

ARRA	The American Recovery and Reinvestment Act of 2009
AMI	Advanced metering infrastructure
AMR	Automated meter reading
DG	Distributed generation
DOE	US Department of Energy
DSM	Demand-side management
EISA 2007	Energy Independence and Security Act of 2007
GHG	Greenhouse gases
HAN	Home Area Network
ISO/RTO	Independent System Operator or Regional Transmission Operator
kW	Kilowatt: one thousand watts of electrical power
kWh	Kilowatt-hour; one thousand watt-hours
MDMS	Meter data-management system
NEG	Net Excess Generation
NGO	Non-Government Organizations
OE	US DOE Office of Electricity Delivery and Energy Reliability
PV	Photovoltaics; solar electric panels
RE	Renewable energy
SSM	Solid-state meter
T&D	An electric utility's transmission and distribution system
TOU	Time-of-use
UOS	Utility operating system

For a comprehensive AMI and time-of-use glossary, see http://www.ferc.gov/industries/electric/indus-act/demand-response/2006/survey/glossary.pdf

Frequently asked questions

Q: What is the difference between AMR, AMI, and Smart Grid? Are they all the same?

A: First, there is a distinction between each of these technologies, and each is evolving. There is not a universally agreed upon definition for any of them. In many cases the technologies overlap. One way to draw a distinction between the technologies is the degree of sophistication of the communications and control systems.

For AMR, the communication system is still one-way, from the customer to the utility. The frequency of communication is intermittent and dependant on the utility to initiate it. Generally, there are no automatic control functions in an AMR system. However, an advanced meter is required, which does have communications capability. Generally, a MDMS is also required and data from the MDMS may be shared with groups, such as system planners within the utility. A HAN is not present and the UOS and the MDMS do not necessarily communicate with each other. Any DSM programs are generally separate from the AMR system, either driven by rate structures or an independent communications system.

For AMI the communication system becomes persistent and two-way. The customer and the utility can now interact with each other. The HAN allows the customer to begin to automate choices about energy use based on signals sent from the utility. Equipment and appliances within the customer's premise can receive signals directly from the utility and change their operating conditions based on predetermined settings made by the customer. The MDMS and the UOS are integrated that allow a higher degree of automation to be present on the utility grid. Algorithms within the UOS utilize data from the MDMS and from other advanced equipment on the utility's grid to determine conditions which allow operators to more effectively control the flow of power and react to abnormal conditions much quicker.

Smart Grid adds a higher degree of automation to the scenario. Intelligent equipment and computer software can make decisions about grid operations that remove human error. These systems can either make suggestions to operators or take control of the grid to reroute the flow of power to mitigate grid congestion or to rectify fault conditionsExactly where the line between these different technologies begin and end can be blurred, particularly between Smart Grid and AMI. However, as a utility moves up the technology curve to Smart Grid, it and its ratepayers will continue to enjoy the benefits of AMR and AMI.

Q: Does a utility have to install AMR, then AMI, then Smart Grid?

A: No, a utility and its regulating body must make a choice about which technology is best suited for the rate payers and the utility. Certainly a utility could begin with an AMR system; in fact many have decided that AMR is the most cost effective of these technologies. However, a utility, with regulatory approval, could start with a Smart Grid application, completely bypassing AMR and AMI.

Q: Why should the RE community worry about Smart Grid technologies? Once a Smart Grid project is installed RE assets such as PV will be able to take advantage of it benefits, right?

A: This seems like a logical conclusion, but there is a great danger to RE if these projects are allowed to be developed without input from the RE community. Each of the components of a Smart Grid system has different features which may affect the cost of the overall system. It is analogous to making a decision about the purchase of a personal computer. Should one choose a desktop or a laptop? Should one choose a separate CD player to ease the process of copying CD's and DVD's, is a separate video card required or is the video capability of the motherboard adequate? Which operating system and software are best to meet the purchaser's needs? How large should the hard drive and RAM be? Each of these choices will impact the performance of the computer system as well as the initial cost. Certainly one would be able to make changes at a later date, i.e. new software or an additional RD player can be added, but usually these modifications are more expensive than they would be had the decision had been made to include them with the original order.

Left to their own, utilities and regulatory bodies are likely to focus on solutions to traditional grid issues. For example, the ability to determine which way the power is flowing by a SSM is a feature that must be specified and may add cost to the meter. If decisions are made based on traditional grid issues, this feature may be omitted; either to reduce costs or because it was not considered necessary. Without this feature, the meter will be unable to credit DG assets for the power they generate; in fact, the customer would be charged for this generation as if it had come from the utility.

Any number of these scenarios can be envisioned that will affect the ability of RE assets to be interconnected, the design of rates and incentives, or the enactment of new policies and legislation favorable to PV and other RE technologies.

Q: Do "Smart Meters" have the capability to disconnect a customer from the grid? If so, would this feature do away with the need for a Utility External Disconnect Switch (UEDS) for PV generators?

A: Currently, some meters have the capability to disconnect a customer's premise for systems up to 200A. This is typically a residential or small commercial customer. However, the communications features of AMI and Smart Grid could easily incorporate this ability for larger systems if the proper equipment is installed at the customers premise.

It should be noted that the need for a Utility External Disconnect Switch has been challenged by the RE community for many years. Michael Sheehan, from the Solar ABCs and Mike Coddington, from NREL, have recently written two excellent position papers on the subject. Many utilities are beginning to eliminate this requirement, and those that have the requirement do not have plans to utilize the UEDS in the event of an outage.

It is the position of the Solar ABCs that a UEDS is not required in any case. If a utility has this requirement and is seeking approval for an AMI or Smart Grid project, this feature should be mandated by regulators and the UEDS requirement should be eliminated.

Expedited Permit Process for PV Systems

A Standardized Process for the Review of Small-Scale PV Systems

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June 2011

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Download this report and the Expedited Permitting Process:

www.solarabcs.org/permitting

Executive Summary

This report presents an expedited permit process for small-scale photovoltaic (PV) systems. The Solar America Board for Codes and Standards (Solar ABCs) recommends that local jurisdictions use this process for awarding building permits to installers of small PV systems. Use of this process simplifies the requirements for the contractor submitting the request and reduces the time needed for the local jurisdiction providing structural and electrical review of the permit application.

The term "expedited permit process" refers to an organized permitting process by which a majority of small, residential-sized photovoltaic systems can be permitted quickly and easily. It is not intended to apply to all types of PV systems. The primary need and value for this process is for systems of less than 10-15 kW of output power. A key difference between small and large projects is the inability of small projects to absorb engineering review costs. Standardizing the process as much as possible is in the contractor's and jurisdiction's interest. As projects increase in size and complexity, the ability to handle these projects via a standard framework diminishes.

The one-page expedited permit process and the accompanying guidelines explaining each step provide a means to differentiate PV systems that can be permitted quickly and easily due to their similarity with the majority of small-scale PV systems. Those systems with unique characteristics may be handled with minimal additions to this expedited process or may require additional information, depending on the uniqueness of the installation.

The diagrams shown in the *Expedited Permit Process* are available online at www.solarabcs.org/permitting in an interactive PDF format so that the diagrams can be filled out electronically and submitted either in printed form or via email to the local jurisdiction. An electronic format is used so that the supplied information is standardized and legible for the local jurisdiction. As this process evolves, and suggestions are received, Solar ABCs will publish additional drawings and diagrams on its website.

The expedited process does provide flexibility in the structural review process. The structural review section includes span tables and additional information found in Appendix B. PV systems with battery backup require a more detailed electrical drawing than this process provides.

Appendix A has an example included of a submittal. An assortment of special electrical topics is presented in *Appendix C*. Temperature tables included in *Appendix E* are used in applying the National Electrical Code's temperature-dependent criteria. This document is intended to be usable throughout the United States and can provide standard installation design documentation for most locations within the U.S. and other regions that use the *National Electrical Code* (NEC), 2011 version (unless otherwise indicated).

Author Biography

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Bill Brooks has worked with utility-interconnected PV systems since the late 1980s. He is a consultant to the PV industry on a variety of performance, troubleshooting, and training topics. Over the past 13 years, these training workshops have helped thousands of local inspectors and thousands of electricians and installers understand PV systems and how to properly install them.

His field troubleshooting skills have been valuable in determining where problems occur and to focus training on those issues of greatest need. Mr. Brooks has written several important technical manuals for the industry that are now widely used in California and beyond. His experience includes work on technical committees for the National Electrical Code, Article 690, and IEEE utility interconnection standards for PV systems. In 2008 he was appointed to Code Making Panel 4 of the National Electrical Code by the Solar Energy Industries Association.

Mr. Brooks holds Bachelor and Master of Science Degrees in Mechanical Engineering from N.C. State University and is a Registered Professional Engineer in both North Carolina and California.

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Solar America Board for Codes and Standards

The Solar America Board for Codes and Standards (Solar ABCs) is a collaborative effort among experts to formally gather and prioritize input from the broad spectrum of solar photovoltaic stakeholders including policy makers, manufacturers, system designers, suppliers, installers, electric utilities, and consumers, resulting in coordinated recommendations to codes and standards making bodies for existing and new solar technologies. The U.S. Department of Energy funds Solar ABCs under the Solar America Initiative Market Transformation (SAI-MT) Program as part of its commitment to facilitate wide-spread adoption of safe, reliable, and cost-effective solar technologies.

For more information, visit the Solar ABCs web site:

www.solarabcs.org.

Acknowledgements

This material is based upon work supported by the Department of Energy under Award Number DE-FC36-07GO17034.

Dedication

This document is dedicated to two key individuals that represent the very best of those who have worked on the codes and standards processes as they relate to PV systems. These two amazing people, Tim Owens, of Santa Clara Building Department, and Chuck Whitaker, of BEW Engineering, passed away in the months prior to the release of this standardized permitting process.

Tim Owens

Tim Owens passed away in December of 2008 at the age of 59 in the midst of a distinguished career in the electrical trades and code enforcement fields. While working as Chief Electrical Inspector for the City of San Diego in 1999, Tim was the first jurisdictional officer to put together a simplified permitting process for PV systems. His desire to see such a process become commonplace is what has driven this author to work on improving permitting and approval processes for PV systems over the past decade. The solar community lost a true friend and partner who was dedicated to the success of solar photovoltaic systems in California and the rest of the U.S.

Chuck Whitaker

Chuck Whitaker passed away in early May of 2009 at the age of 52 in the midst of a distinguished career supporting the development and implementation of most of the codes and standards the govern and support PV systems both nationally and internationally. His passing coincided with the initial release of this standardized permitting process.. The author had the privilege of knowing Chuck for two decades and working closely with him for over eight years as his employee and colleague. It is difficult to overstate Chuck's contribution to the PV industry; his influence is found in nearly every code and standard that has been developed for PV equipment and systems over the past 25 years. It is only fitting that this document—which includes his influence—be dedicated to his memory. A huge hole is left in the PV industry with Chuck's passing, and it is the hope of many of us in the codes and standards arena to be able to carry on his tireless work some semblance of the skill, wit, and humor that were the hallmarks of this amazing individual.

Table of Contents

Disclaimer ii

Executive Summary iii

Author Biography iv

Dedication v

Introduction 1

What Qualifies a PV Project for Expedited Permitting? 1

The Permitting Process for PV Systems in the United States 2

Problems with the Existing Processes of Permitting PV systems 2

Activities to Develop Standardized Review Processes 3

Unifying the existing permitting processes to Move Toward a Standardized Expedited Permit Process 4

Recommendations on applying the Expedited Permit Process 4

References 5

Expedited Permit Process for PV Systems 6

Expedited Permit Process for Small-Scale PV Systems 7

Expedited Permit Guidelines for Small-Scale PV Systems 11

- Section 1. Required Information for Permit 11
- Section 2. Step 1: Structural Review of PV Array Mounting System 11
- Section 3. Step 2: Electrical Review of PV System 13
- Section 4. Inverter Information 14
- Section 5. Module Information 14
- Section 6. Array Information 15
- Section 7. Signs 16
- Section 8. Wiring and Overcurrent Protection 17
- Section 9: AC Point of Connection 20
- Section 10: Grounding 21

Appendix A: Example Submittals 23

Appendix B: Structural 32

Appendix C: Micro-Inverter and AC Modules 34

Appendix D: Special Electrical Topics 39

Appendix E: Cost of Permits 45

Appendix F: Temperature Tables 46

Introduction

The term "expedited permit process" refers to an organized permitting process by which a majority of small photovoltaic (PV) systems can be permitted quickly and easily. It is not intended to apply to all types of PV systems. The primary need and value for this process is for systems of less than 10-15 kW maximum power output. As PV systems increase in size and complexity, the ability to handle these projects via a standard framework diminishes. This is not to say that larger systems cannot be handled in a straightforward manner. Many larger PV system projects may be approved with minimum review as is required with smaller systems. A key difference between small and large projects is the inability of small projects to absorb engineering review costs. The expedited permit process is intended to simplify the structural and electrical review of a small PV system project and minimize the need for detailed engineering studies and unnecessary delays.

It is not the intent of an expedited process to circumvent the engineering process. Rather, the intent is to address the engineering concerns by recognizing the similarities among these smaller systems and establishing guidelines to determine when a PV project is within the boundaries of typical, well-engineered systems. To this end, a one-page permit form was devised to outline the process and define what qualifies for expedited permitting. An explanatory document accompanies the permit form so that contractors and local jurisdictions using the form have a description of how to provide the required information.

What Qualifies a PV Project for Expedited Permitting?

The permit form outlines what information is needed for the permit package and the minimum requirements needed for utilizing expedited permitting as summarized below.

1. The structural installation of the systems meets the following criteria:
    a. the array is mounted on a code-compliant structure;
    b. an engineered mounting system is used to attach the array to the structure; and,
    c. the array has a distributed weight of less than 5 lbs./ft^2 and less than 45 lbs. per attachment.
2. The electrical design of the system can be described using the supplied standard electrical diagram and meets the following criteria:
    a. all products are listed and identified for the application (i.e. modules, inverters, source combiners, etc.);
    b. the array is composed of 4 series strings or less and,
    c. the inverter output is 13.44 kW or less (maximum size for 70-amp breaker) and is connected on the load side of the service disconnect.

In order to complete the permit package, the applicant is required to provide the following:

1. a completed permit application
2. the proposed site diagram showing the relative location of major components
3. the proposed standard electrical diagram
4. the specification sheets and simple instruction manuals for major components.

Even though these stipulations may seem restrictive at first, the majority of PV systems installed in the U.S. will easily meet these requirements. For projects that do not meet these simplified criteria, additional steps may be necessary. Currently, the expedited process identifies steps to complete the review of the structural installation should the array be installed on a roof that is unfamiliar to the jurisdiction, or when a non-

typical mounting system is employed. For installations that do not meet the electrical installation criteria, detailed ampacity calculations, and other supporting documentation may be necessary to complete the review. A variety of special cases will be added to the standard electrical diagram case to accommodate project types that are composed of additional system installations (e.g. supply-side connections, modular inverter systems, and battery-based systems).

Finally, it should be noted that an expedited permit process solves only one of several challenges in the installation process of PV systems. Increasingly, local jurisdictions across the U.S. are placing less emphasis on the permit process and more emphasis on the field inspection process. This is a positive trend for the PV industry, as even the best permit package may do little to reduce challenges during a field inspection. Ultimately, the field inspection will illustrate how well a contractor is able to install a code-compliant PV system. A well-organized permit package may simply make a poor-quality contractor look good initially, while the final inspection can more clearly identify competent installers. Understanding that this permit process is only one portion of the code-enforcement process will help advocates and jurisdictions put the appropriate emphasis on the review and inspection portions of the process.

The Permitting Process for PV Systems in the United States

In order to understand how an expedited permitting process can be of assistance, we should first examine how permitting in general is conducted throughout the U.S. A common method that local jurisdictions utilize is to split the process into two discrete segments: 1) permitting, and 2) field inspection.

The first segment entails both the plan review and permitting process. Depending on the size of the jurisdiction, this process will vary. For large jurisdictions, there may be a group of people that focuses only on plan reviews and typically does not get involved in the field inspection process. For smaller jurisdictions, one person may be providing the plan review, field inspection, and other services of the office. Understanding that these processes can vary significantly is key in helping jurisdictions choosing to adopt a standardized process.

In addition to the more common standard plan review and inspection processes, there are a many other methods used across the U.S. Many rural areas do not require permits or inspections for construction. Other regions may use third-party inspectors who provide the local government with a certificate that an installation meets local code requirements.

Finally, some jurisdictions have a very minimal or non-existent permit process, with all the emphasis placed on the field inspection. This minimal permit process might include simply mailing, faxing, or emailing a short form into an office or going online and paying a fee. This expedited permit process may contain more steps than some jurisdictions require. However, even for those jurisdictions that do not require plan submittals, the documentation can be supplied at the field inspection for reference.

Problems with the Existing Processes of Permitting PV systems

Given the differences in permitting processes across the U.S., and the significant variations in experience relating to system inspection at various jurisdictions, it becomes apparent why permitting issues have been cited as a barrier to the widespread installation of PV systems. Several articles and reports have been written, documenting general permitting difficulties and cite specific examples of difficulties and delays for

PV system projects as a result of the permitting process. A recent report entitled, *Taking the Red Tape out of Green Power,* written by Damian Pitt of the Network of New Energy Choices, outlines many of these issues (Pitt, 2008). The report highlights many issues that create barriers to successful PV system installations, and include references to complex and inconsistent permitting processes throughout various jurisdictions.

The expedited permit process proposed in this report will assist jurisdictions in removing complexities and creating a more consistent permitting process. The complexities of the permitting processes are often a result of jurisdictions requiring that multiple departments review permit applications. As a jurisdiction becomes familiar with the expedited permitting process, a simple review by a single department will often be sufficient. The second obstacle, lack of consistency among jurisdictions, is addressed by the very intent of the standard permitting process. As the Pitt report points out, it is not necessarily the amount of information required that is the problem, but rather the uncertainty of not knowing whether the information being supplied is sufficient (Pitt, 2008). Each time a request for additional information is issued by a jurisdiction, days are added to the approval timeframe for the project and costs increase for both the jurisdiction and the contractor.

Activities to Develop Standardized Review Processes

As we seek to develop a single, uniform permitting process for small-scale PV systems, we must acknowledge the fact that this is not a new concept. As long ago as 1999, the City of San Diego, under the leadership of the chief electrical inspector Tim Owens, attempted to standardize the permit process for PV systems. At about the same time, the Florida Solar Energy Center (FSEC) started their PV System Design Review and Approval program. This detailed design review and approval program was developed to support a Florida rebate program for PV systems up to 100 kW, and was later standardized into FSEC Standard 203-05, *Procedures for Photovoltaic System Design Review and Approval*. The approval is based on the system design complying with the applicable codes and standards, and its consistency with industry-accepted design practices.

Since the turn of the millennium, many other organizations and jurisdictions have developed standardized permit processes. In 2004, the Interstate Renewable Energy Council (IREC) and Pace University in New York put together the first Inspector Guideline for PV Systems. This project was funded by the U.S. Department of Energy (DOE) and received fairly widespread use throughout the U.S. Dozens of jurisdictions in California and across the U.S. have been using this document as a tool to help them review PV system projects and as a template to request information from contractors.

As PV systems began to proliferate in large markets such as California and New Jersey, the pressure to develop standardized permit processes increased. Other organizations such as the Sierra Club and SolarTech in the San Francisco Bay area, and the Colorado Solar Energy Industries Association (CoSEIA) began developing new processes. Although many of the new processes were based on the DOE guidelines, new items were added to address concerns that the DOE guidelines may not have covered. In addition to private organizations working on guidelines, numerous local jurisdictions developed guidelines as well. Among these jurisdictions are the City of Ventura, California, and regional International Code Council (ICC) chapters, such as the County of Sonoma and the ICC Tri-Chapter Uniform Code Committee (TUCC) in the San Francisco Bay area.

Unifying the existing permitting processes to Move Toward a Standardized Expedited Permit Process

With all the energy and focus being placed on this specific issue, the timing was right to work with all these jurisdictions and organizations to determine whether a single process could be developed that met the concerns of all the parties and that could be used as a nationwide template for jurisdictions. By incorporating the major components of each of the developed processes, the Expedited Permit Process was drafted and released for review in early March, 2009. This new permitting process was significantly different from the previous DOE guidelines and included many of the unique aspects of the SolarTech and TUCC documents.

Over the course of March and April of 2009, numerous reviews of the draft document were provided by solar contractors, individuals at organizations including SolarTech, National Renewable Energy Laboratory (NREL), New Mexico State University (NMSU), California Solar Energy Industries Association (CalSEIA), CoSEIA, and jurisdictions that had expressed interest in reviewing the draft. As a result of these reviews, substantial updates and changes were made to the content of the process. In particular, the electrical diagram went from a single 11"x17" diagram with areas to fill in the specifications of the electrical components to two 8.5"x11" diagrams that can be filled in electronically using a PDF reader. Other comments suggested adding descriptions of special cases, such as making ac connections on the supply side of service disconnect and making ac connections to subpanels. Rather than incorporate these special topics into the body of the explanatory document, each item is addressed separately in the appendix under Special Electrical Topics.

The feature that sets the expedited permit process apart from other current standardization attempts is the development of a standard electrical diagram and standard wire sizing. This diagram is pivotal to the development of a standard permit process. Variations in how electrical design information is presented can be a major problem for jurisdictions approving projects. These variations often cause permitting delays as the jurisdictions are unsure about what information is being provided, or left out, when the permit application is submitted. This uncertainty often causes jurisdictions to set a one- or two-week turn around for PV projects. A standard diagram can remove that uncertainty and allow a jurisdiction to review and approve a project at the time of submittal. What is often termed "over the counter" approvals is one of the goals of the Expedited Permit Process. "Over the counter" refers to a local jurisdictional review provided by plan checkers that are available at the permitting counter. A highly organized standardized permit package makes this type of counter review possible.

Recommendations on applying the Expedited Permit Process

It is likely that various regions and jurisdictions across the United States have regulations and requirements that restrict their ability to adopt the expedited permitting process. At the same time, the issues that jurisdictions face when permitting PV systems are often similar. All jurisdictions must address the safety of PV systems as they affect structures and electrical hazards. The key is beginning with a consistent starting point in the development of a local or regional requirement. By using the new expedited permit process provided by the Solar America Board for Codes and Standards (Solar ABCs), jurisdictions can be assured that they are consistent in their application of codes and standards. Contractors can also be assured that the requirements for permitting will not vary dramatically among jurisdictions.

Solar ABCs recommends that this permitting process be used in its entirety. As jurisdictions begin to use this process and see opportunities to improve the guidelines the updates can be

implemented and posted on the Solar ABCs website at www.solarabcs.org/permitting. With this approach, the latest version can be found and downloaded from a consistent location and jurisdictions can update their local processes as often as they deem necessary. By having a process that can be consistently updated, the permitting process can stay current with the design and installation practices as they change over time. The ultimate goal is to have the best and most up-to-date information on PV system design and installation practices in the hands of jurisdictions and contractors across the U.S. As codes are updated and changed, this flexible system can be adapted quickly and easily.

References

National Fire Protection Association, (*2011), National Electrical Code 2011*.

Pitt, D., *(2008) Taking the Red Tape Out of Green Power: How to Overcome Permitting Obstacles to Small-Scale Distributed Renewable Energy, Network for New Energy Choices*. Retrieved 9/4/09 from http://www.newenergychoices.org/uploads/redTape-rep.pdf

Expedited Permit Process for PV Systems

The Solar America Board for Codes and Standards (Solar ABCs) Expedited Permit Process provides a means to differentiate systems that can be permitted quickly and easily due to their similarity with the majority of small-scale PV systems. Those systems with unique characteristics may be handled with small additions to this Expedited Permit Process or may require much more information, depending on the uniqueness of the installation.

The following pages contain forms to use with the Expedited Permit Process. The forms are available as interactive PDF files at www.solarabcs.org/permitting. In jurisdictions that have adopted the Expedited Permit Process for PV Systems, these forms can be filled out electronically and submitted in either printed form and via email. An electronic format is used so that the supplied information is standardized and legible for the local jurisdiction.

Expedited Permit Process for Small-Scale PV Systems

The information in this guideline is intended to help local jurisdictions and contractors identify when PV system installations are simple, needing only a basic review, and when an installation is more complex. It is likely that 50%-75% of all residential systems will comply with these simple criteria. For projects that fail to meet the simple criteria, resolution steps have been suggested to provide as a path to permit approval.

Required Information for Permit:

1. Site plan showing location of major components on the property. This drawing need not be exactly to scale, but it should represent relative location of components at site (see supplied example site plan). PV arrays on dwellings with a 3' perimeter space at ridge and sides may not need separate fire service review.
2. Electrical diagram showing PV array configuration, wiring system, overcurrent protection, inverter, disconnects, required signs, and ac connection to building (see supplied standard electrical diagram).
3. Specification sheets and installation manuals (if available) for all manufactured components including, but not limited to, PV modules, inverter(s), combiner box, disconnects, and mounting system.

Step 1: Structural Review of PV Array Mounting System

Is the array to be mounted on a defined, permitted roof structure? ☐ **Yes** ☐ **No**

If No due to non-compliant roof or a ground mount, submit completed worksheet for the structure WKS1.

Roof Information:

1. Is the roofing type lightweight (Yes = composition, lightweight masonry, metal, etc…)_____

If No, submit completed worksheet for roof structure WKS1 (No = heavy masonry, slate, etc…).

2. Does the roof have a single roof covering? ☐ **Yes** ☐ **No**

If No, submit completed worksheet for roof structure WKS1.

3. Provide method and type of weatherproofing roof penetrations (e.g. flashing, caulk)._____

Mounting System Information:

1. Is the mounting structure an engineered product designed to mount PV modules with no more than an 18" gap beneath the module frames? ☐ **Yes** ☐ **No**

If No, provide details of structural attachment certified by a design professional.

2. For manufactured mounting systems, fill out information on the mounting system below:
   a. Mounting System Manufacturer _____Product Name and Model#_____
   b. Total Weight of PV Modules and Rails _____lbs
   c. Total Number of Attachment Points_____
   d. Weight per Attachment Point (b ÷ c)_____lbs (if greater than 45 lbs, see WKS1)
   e. Maximum Spacing Between Attachment Points on a Rail _____inches (see product manual for maximum spacing allowed based on maximum design wind speed)
   f. Total Surface Area of PV Modules (square feet)_____ ft^2
   g. Distributed Weight of PV Module on Roof (b ÷ f)_____ lbs/ft^2

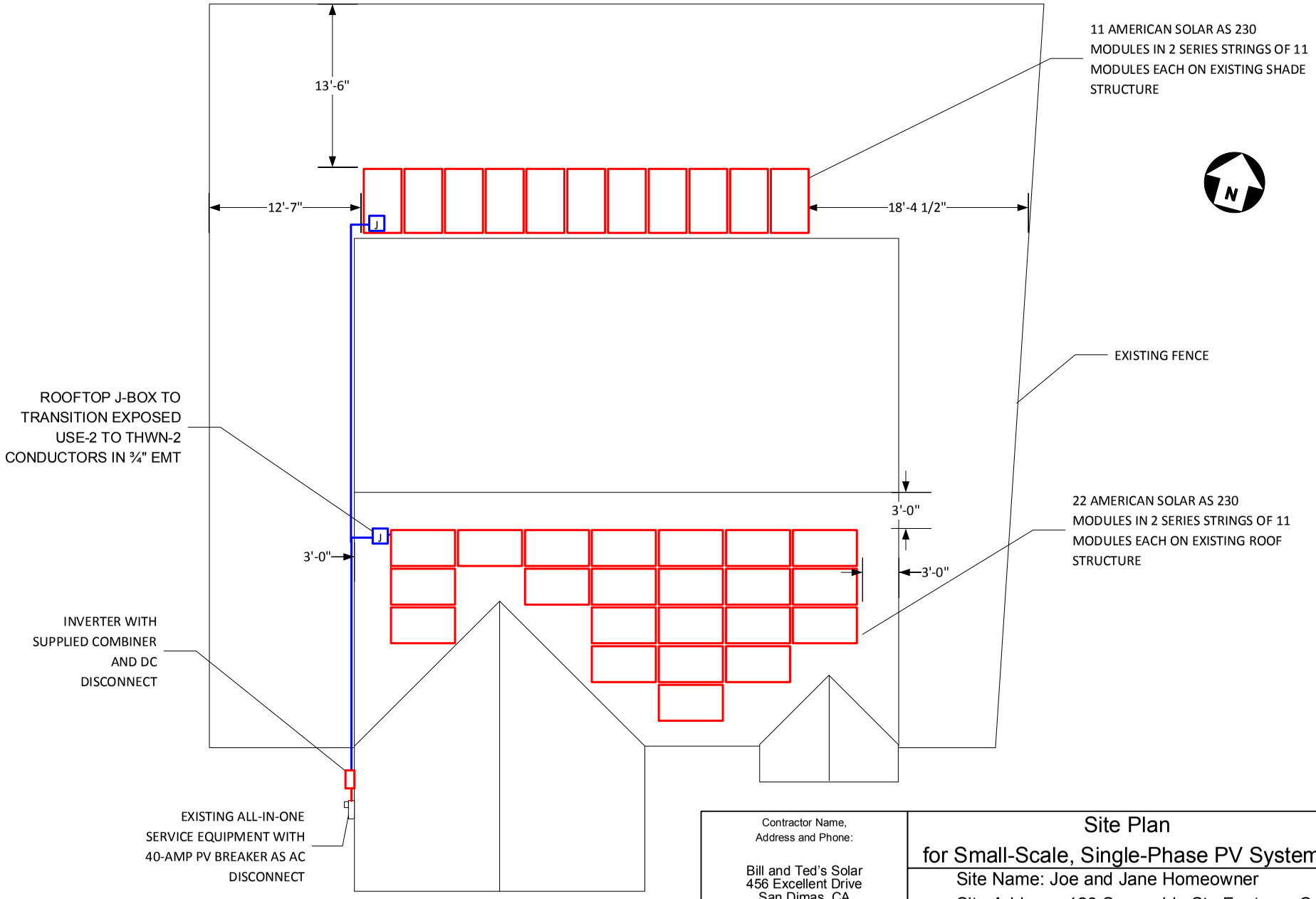
   If distributed weight of the PV system is greater than 5 lbs/ft^2, see WKS1.

Step 2: Electrical Review of PV System (Calculations for Electrical Diagram)

In order for a PV system to be considered for an expedited permit process, the following must apply:

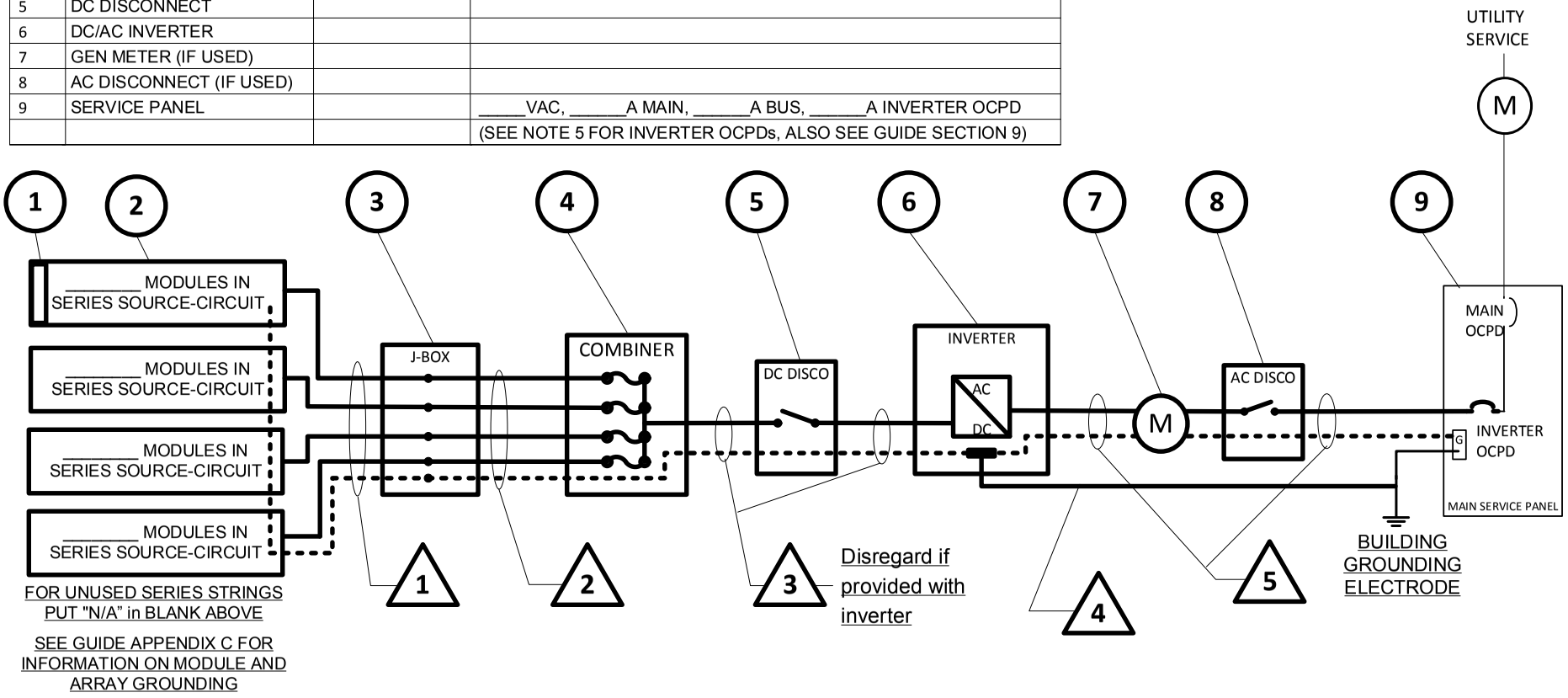
1. PV modules, utility-interactive inverters, and combiner boxes are identified for use in PV systems.
2. The PV array is composed of 4 series strings or less per inverter.
3. The total inverter capacity has a continuous ac power output 13,440 Watts or less
4. The ac interconnection point is on the load side of service disconnecting means (690.64(B)).
5. One of the standard electrical diagrams (E1.1, E1.1a, E1.1b, or E1.1c) can be used to accurately represent the PV system. Interactive PDF diagrams are available at www.solarabcs.org/permitting.

Fill out the standard electrical diagram completely. A guide to the electrical diagram is provided to help the applicant understand each blank to fill in. If the electrical system is more complex than the standard electrical diagram can effectively communicate, provide an alternative diagram with appropriate detail.



Contractor Name, Address and Phone: Bill and Ted's Solar 456 Excellent Drive San Dimas, CA 800-555-1212	Site Plan for Small-Scale, Single-Phase PV Systems Site Name: Joe and Jane Homeowner Site Address: 123 Sunnyside St., Fontana, CA System AC Size: 6.0 kW Solar Array
Drawn By: Bill Checked By: Ted	SIZE · FSCM NO · DWG NO S1.1a · REV 0 SCALE NTS · Date: · SHEET

EQUIPMENT SCHEDULE			
TAG	DESCRIPTION	PART NUMBER	NOTES
1	SOLAR PV MODULE		
2	PV ARRAY		
3	J-BOX (IF USED)		
4	COMBINER (IF USED)		
5	DC DISCONNECT		
6	DC/AC INVERTER		
7	GEN METER (IF USED)		
8	AC DISCONNECT (IF USED)		
9	SERVICE PANEL		_____VAC, _____A MAIN, _____A BUS, _____A INVERTER OCPD
			(SEE NOTE 5 FOR INVERTER OCPDs, ALSO SEE GUIDE SECTION 9)



△ CONDUIT AND CONDUCTOR SCHEDULE					
TAG	DESCRIPTION OR CONDUCTOR TYPE	COND. GAUGE	NUMBER OF CONDUCTORS	CONDUIT TYPE	CONDUIT SIZE
1	USE-2 ☐ or PV WIRE ☐			N/A	N/A
	BARE COPPER EQ. GRD. COND. (EGC)			N/A	N/A
2	THWN-2 ☐ or XHHW-2 ☐ or RHW-2 ☐				
3	THWN-2 ☐ or XHHW-2 ☐ or RHW-2 ☐				
	INSULATED EGC				
4	DC GROUNDING ELECTRODE COND.				
5	THWN-2 ☐ or XHHW-2 ☐ or RHW-2 ☐				
	INSULATED EGC				

Contractor Name, Address and Phone:

_____
_____
_____
_____

Drawn By:

Checked By:

One-Line Standard Electrical Diagram for Small-Scale, Single-Phase PV Systems

Site Name: _____

Site Address: _____

System AC Size: _____

SIZE	FSCM NO	DWG NO	REV
		E1.1	

SCALE	NTS	Date:	SHEET

Notes for Electrical Diagram

PV MODULE RATINGS @ STC (Guide Section 5)

MODULE MAKE	
MODULE MODEL	
MAX POWER-POINT CURRENT (I_{MP})	A
MAX POWER-POINT VOLTAGE (V_{MP})	V
OPEN-CIRCUIT VOLTAGE (V_{OC})	V
SHORT-CIRCUIT CURRENT (I_{SC})	A
MAX SERIES FUSE (OCPD)	A
MAXIMUM POWER (P_{MAX})	W
MAX VOLTAGE (TYP 600V_{DC})	V
VOC TEMP COEFF (mV/°C ☐ or %/°C ☐)	
IF COEFF SUPPLIED, CIRCLE UNITS	

NOTES FOR ALL DRAWINGS:

OCPD = OVERCURRENT PROTECTION DEVICE

NATIONAL ELECTRICAL CODE® REFERENCES SHOWN AS *(NEC XXX.XX)*

INVERTER RATINGS (Guide Section 4)

INVERTER MAKE	
INVERTER MODEL	
MAX DC VOLT RATING	V
MAX POWER @ 40°C	W
NOMINAL AC VOLTAGE	V
MAX AC CURRENT	A
MAX OCPD RATING	A

SIGNS–SEE GUIDE SECTION 7

SIGN FOR DC DISCONNECT

PHOTOVOLTAIC POWER SOURCE	
RATED MPP CURRENT	A
RATED MPP VOLTAGE	V
MAX SYSTEM VOLTAGE	V
MAX CIRCUIT CURRENT	A

WARNING: ELECTRICAL SHOCK HAZARD–LINE AND LOAD MAY BE ENERGIZED IN OPEN POSITION

SIGN FOR INVERTER OCPD AND AC DISCONNECT (IF USED)

SOLAR PV SYSTEM AC POINT OF CONNECTION	
AC OUTPUT CURRENT	A
NOMINAL AC VOLTAGE	V

THIS PANEL FED BY MULTIPLE SOURCES (UTILITY AND SOLAR)

NOTES FOR ARRAY CIRCUIT WIRING (Guide Section 6 and 8 and Appendix D):

1.) LOWEST EXPECT AMBIENT TEMPERATURE BASED ON ASHRAE MINIMUM MEAN EXTREME DRY BULB TEMPERATURE FOR ASHRAE LOCATION MOST SIMILAR TO INSTALLATION LOCATION. LOWEST EXPECTED AMBIENT TEMP _____°C

2.) HIGHEST CONTINUOUS AMBIENT TEMPERATURE BASED ON ASHRAE HIGHEST MONTH 2% DRY BULB TEMPERATURE FOR ASHRAE LOCATION MOST SIMILAR TO INSTALLATION LOCATION. HIGHEST CONTINUOUS TEMPERATURE _____°C

2.) 2005 ASHRAE FUNDEMENTALS 2% DESIGN TEMPERATURES DO NOT EXCEED 47°C IN THE UNITED STATES (PALM SPRINGS, CA IS 44.1°C). FOR LESS THAN 9 CURRENT-CARRYING CONDUCTORS IN ROOF-MOUNTED SUNLIT CONDUIT AT LEAST 0.5" ABOVE ROOF AND USING THE OUTDOOR DESIGN TEMPERATURE OF 47°C OR LESS (ALL OF UNITED STATES),

a) 12 AWG, 90°C CONDUCTORS ARE GENERALLY ACCEPTABLE FOR MODULES WITH Isc OF 7.68 AMPS OR LESS WHEN PROTECTED BY A 12-AMP OR SMALLER FUSE.

b) 10 AWG, 90°C CONDUCTORS ARE GENERALLY ACCEPTABLE FOR MODULES WITH Isc OF 9.6 AMPS OR LESS WHEN PROTECTED BY A 15-AMP OR SMALLER FUSE.

NOTES FOR INVERTER CIRCUITS (Guide Section 8 and 9):

1) IF UTILITY REQUIRES A VISIBLE-BREAK SWITCH, DOES THIS SWITCH MEET THE REQUIREMENT? YES ☐ NO ☐ N/A ☐

2) IF GENERATION METER REQUIRED, DOES THIS METER SOCKET MEET THE REQUIREMENT? YES ☐ NO ☐ N/A ☐

3) SIZE PHOTOVOLTAIC POWER SOURCE (DC) CONDUCTORS BASED ON MAX CURRENT ON NEC 690.53 SIGN OR OCPD RATING AT DISCONNECT

4) SIZE INVERTER OUTPUT CIRCUIT (AC) CONDUCTORS ACCORDING TO INVERTER OCPD AMPERE RATING. (See Guide Section 9)

5) TOTAL OF _____ INVERTER OCPD(s), ONE FOR EACH INVERTER. DOES TOTAL SUPPLY BREAKERS COMPLY WITH 120% BUSBAR EXCEPTION IN 690.64(B)(2)(a)? YES ☐ NO ☐

Contractor Name, Address and Phone: _____	Notes for One-Line Standard Electrical Diagram for Single-Phase PV Systems			
	Site Name: _____			
	Site Address: _____			
	System AC Size: _____			
Drawn By:	SIZE	FSCM NO	DWG NO E1.2	REV
Checked By:	SCALE NTS	Date:	SHEET	

Section 1. Required Information for Permit

1. Site plan showing location of major components on the property. This drawing need not be to scale, but it should represent relative location of components at site. (see supplied example site plan).

   Explanation: This is a simple diagram to show where the equipment is located on the property. This can be a zone-clearance plot plan with the equipment clearly shown and identified on the plan. If PV array is ground-mounted, clearly show that system will be mounted within allowable zoned setbacks. See site plan example drawing in permit process for reference.

2. Electrical diagram showing PV array configuration, wiring system, overcurrent protection, inverter, disconnects, required signs, and ac connection to building (see supplied standard electrical diagram).

   Explanation: The cornerstone of a simplified permit process is the ability to express the electrical design with a generic electrical diagram. This diagram has been designed to accurately represent the majority of single-phase, residential-sized PV systems. PV systems may vary dramatically in PV array layout and inverter selection. However, the majority of small-scale, residential-sized PV systems can be accurately represented by this diagram. This diagram must be fully completed filled out in order for the permit package to be submitted.

3. Specification sheets and installation manuals (if available) for all manufactured components including, but not limited to, PV modules, inverter(s), combiner box, disconnects, and mounting system.

   Explanation: At a minimum, specification sheets must be provided for all major components. In addition to the components listed, other important components may be specialty fuses, circuit breakers, or any other unique product that may need to be reviewed by the local jurisdiction. Installation manuals are also listed in this item. This is referring to the brief versions of manuals that are reviewed by the listing agency certifying the product. Some detailed installation manuals can be several dozens or hundreds of pages. If the local jurisdiction feels it is necessary to review these large documents, a good alternative would be for the documents to be supplied electronically, rather than in print.

Section 2. Step 1: Structural Review of PV Array Mounting System

1. Is the array to be mounted on a defined, permitted roof structure? ☐ **Yes** ☐ **No** (structure meets modern codes)

If No, submit completed worksheet for roof structure WKS1.

Explanation: The reference to a defined, permitted roof structure refers to structures that have a clear inspection history so that verification of structural elements is unnecessary. If structural modifications have been made due to remodeling, those changes should be documented through the permit and review process. It also recognizes the fact that code enforcement for roof structural elements has been much more consistent across the United States in the last 35 years. However, there may be many local jurisdictions who have been carefully reviewing roof structures for a much longer period of time. The local jurisdiction should consider extending this limit based on the period that roofs have been consistently inspected. In areas where jurisdictional reviews have not extended 35 years into the past, the jurisdiction may need to get the information from WKS1 to be sure whether or not the proposed PV system is being installed on a typical roof structure or not.

Roof Information:

1. Is the roofing type lightweight (Yes = composition, lightweight masonry, metal, wood shake, etc.)_____

If No, submit completed worksheet for roof structure WKS1 (No = heavy masonry, slate, etc.).

Explanation: There is a need to distinguish if a roof has a lightweight product. Roof structures supporting heavier roofing materials (e.g. slate, heavy masonry) may not have the assumed dead loading and live loading capacities that are found with lighter weight roofing materials. These are much less common roof types and often justify a further review to clarify whether the roof structure is either in compliance or needs enhancement.

2. If a composition shingle roof, does the roof have a single roof covering? ☐ **Yes** ☐ **No**

If No, submit completed worksheet for roof structure WKS1.

Explanation: *Multiple composition roof layers may be taking a portion or all of the assumed additional weight allowance found in the 5 lbs/ft² allowance at the end of the mounting system section.*

3. Provide method and type of weatherproofing roof penetrations (e.g. flashing, caulk.)_____

Explanation*: The weatherproofing method needs to be specifically identified so that plan checkers and field inspectors are notified ahead of time of the method being used. Some jurisdictions may constrain weatherproofing methods and materials. Sealant information should confirm that the product is compatible with the roofing material.*

Mounting System Information:

1. Is the mounting structure an engineered product designed to mount PV modules with no more than an 18" gap beneath the module frames? ☐ **Yes** ☐ **No**

If No, provide details of structural attachment certified by a design professional.

Explanation*: Non-engineered racking systems have undefined capabilities. PV systems should only be mounted using systems that are engineered and designed for that purpose. Structural loading of a roof is more complex when modules are angled more than 18" above the roof surface. For simplicity, this process has been limited to PV arrays that are mounted parallel to the roof surface or angled with no more than an 18" gap between the module frame and the roof surface. If an installer chooses to mount the PV modules with a larger gap or if they use a mounting system of unique design, then the mounting design would require a review by a design professional.*

2. For manufactured mounting systems, fill out information on the mounting system below:

a. Mounting System Manufacturer _____Product Name and Model#_____ (self-explanatory)

b. Total Weight of PV Modules and Rails _____lbs (include total weight of all hardware used along with module weight)

c. Total Number of Attachment Points_____(self-explanatory)

d. Weight per Attachment Point (b ÷ c)_____lbs (if greater than 45 lbs, see WKS1)

Explanation*: 45 lbs has been used by some jurisdictions as a reasonable level below which point loading of roof joists and trusses can be ignored. Most standard mounting systems have point loadings of 25-35 lbs per attachment.*

e. Maximum Spacing Between Attachment Points on a Rail _____inches (see product manual for maximum spacing allowed based on wind loading)

Explanation*: Depending on the wind loading requirements of a particular jurisdiction, the spacing or attachments may be dictated by the manufacturer's directions. For instance, a particular manufacturer may allow a 72" attachment spacing for a 90 MPH windspeed design, but the spacing reduces to a maximum of 48" when the design windspeed exceeds 100 MPH.*

f. Total Surface Area of PV Modules (square feet)_____ ft²

Explanation*: Take the surface area of a single module, and multiply it by the total number of modules in the roof-mounted system.*

g. Distributed Weight of PV System on Roof (b ÷ f)_____ lbs/ft²

If distributed weight of the PV system is greater than 5 lbs/ft², see WKS1.

Explanation*: The 5 lbs/ft² limit is based on two things: 1) the roof is typical of standard code-compliant roof structures so that the structure either has the proper spans and spacing, or proper use of engineered trusses (first item under "Step 1: Structural Review"); and, 2) there is a single layer of roofing so that the normal weight allowance for additional roof layers is unused and available for the weight of the PV system. For applications on lightweight masonry roofing materials and other lightweight roofing products (e.g. metal, shake, etc.), these materials do not accept multiple layers and therefore the 5 lbs/ft² allowance is used to identify the maximum allowable additional weight for roofs that are exchanging the allowable live load for a dead load that prevents live load such as people walking on the roof.*

Section 3. Step 2: Electrical Review of PV System (Calculations for Electrical Diagram)

In order for a PV system to be considered for an expedited permit process, the following must apply:

1. PV modules, utility-interactive inverters, and combiner boxes are identified for use in PV systems.

***Explanation**: PV utility-interactive inverters must be specifically listed and labeled for this application [NEC 690.60 and 690.4] (Brackets refer to sections in the 2011 NEC throughout this document.)Without this specific identification process an unacceptable amount of review would be necessary to approve an inverter. Inverters that pass UL1741 and are listed as "utility-interactive" have met the requirement. Over 500 inverters currently meet this requirement. An inclusive list of these inverters is available online at http://gosolarcalifornia.com/equipment/inverter.php.*

PV modules must also be listed and identified for use in PV systems [NEC 690.4]. PV modules that pass UL1703 and have a 600-Volt maximum voltage meet the requirement. A list of these modules is available online at http://gosolarcalifornia.com/equipment/pvmodule.php. Source-circuit combiners must be listed and labeled to meet the dc voltage requirements of the PV system or be specifically tested for PV systems and clearly state the allowable maximum current and voltage [NEC 690.4].

2. The PV array is composed of 4 series strings or less, for AC module and micro-inverter arrays, PV array is composed of 4 branch circuits or less.

***Explanation**: The purpose of this requirement is to limit the number of options of what can comply as a "simple" system so that a single electrical diagram can be used to describe a large percentage of the systems being installed. The electrical diagram can handle up to 4 strings or branch circuits in parallel. This ensures that the conduit will have no more than eight current-carrying conductors, which the ampacity tables in this guide have been based upon.*

3. The combined inverter continuous AC power output 13,440 Watts or less.

***Explanation**: The limit is set to stay generally within electrical interconnections that would be considered simple and possibly able to meet the 120% of busbar rating allowance in NEC 690.64(B) in a residence (Minimum breaker for a 13.44 kWac PV system is 70 amps at 240Vac). A 70-amp breaker is important since a 225-amp busbar in a 200-amp panel will allow a 70-amp PV breaker. Since this does happen from time to time, and an installer can choose to install such a panelboard, it is considered the largest "simple" PV system for purposes of this guideline. A table of breaker/ panelboard combinations is in Section 9 of this Guideline.*

4. The ac interconnection point is on the load side of service disconnecting means (NEC 690.64(B)).

***Explanation**: Load side interconnections are by far the most common, particularly in residential applications. Any line side connection is covered by NEC 690.64(A) and 230.82. Although line side connections can be quite straightforward, they should require an additional step in the approval process and require a slightly different electrical drawing.*

5. One of the standard electrical diagrams (E1.1, E1.1a, E1.1b, or E1.1c) can be used to accurately represent the PV system. Interactive PDF diagrams are available at www.solarabcs.org/permitting.

***Explanation**: The basis for a simplified permit is the use of the standard electrical diagram. Clearly, PV systems can vary significantly in PV array layout and inverter selection. However, the majority of small-scale, residential-sized PV systems can be accurately represented by this diagram. This diagram must be completely filled out in order for the permit package to be considered complete. This diagram is not intended for use with battery-based systems. Interactive PDF versions of all the standard electrical diagrams can be found at www.solarabcs.org/permitting. These diagrams allow values to be input and the page to be saved and printed.*

Section 4. Inverter Information

A copy of the manufacturer's specification sheet is required for a permit submittal. In addition, a printed out digital photo of the inverter listing label can be very helpful for gathering the ratings of the equipment.

a. INVERTER MAKE: This is the manufacturer's name (e.g. Motech, PV Powered, SMA, etc.)

b. INVERTER MODEL #: This is the model number on the listing label (e.g. PVMate 3840U, PVP 5200, SB7000US, etc.)

c. MAX DC VOLTAGE RATING: Provided either on listing label or specification sheet.

d. MAX POWER @ 40°C: The maximum continuous output power at 40°C is required information for the listing label and the Go Solar California website. If the specification sheet does not clearly state the value, consult either of these other two sources.

e. NOMINAL AC VOLTAGE: This is the ac output voltage of the inverter as configured for this project. Some inverters can operate at multiple ac voltages.

f. MAX OCPD RATING: This is the maximum overcurrent protective device (OCPD) rating allowed for the inverter. This is either stated on the listing label or in the installation manual. Sometimes this is also listed on the specification sheet—but not always. It is important to check that the inverter OCPD rating in the panel is less than or equal to this maximum rating to preserve the listing of the inverter.

Section 5. Module Information

A copy of the manufacturer's specification sheet is required for a permit submittal. In addition, a printed out digital photo of the module listing label can be very helpful for gathering the ratings of the equipment. A prerequisite for a code-approved installation is the use of PV modules listed UL 1703 [NEC 690.4]. For a current list of modules that are listed to UL 1703, visit the *Go Solar California* website, *http://gosolarcalifornia.com/equipment/pvmodule.php*.

***Explanation**: This module information is particularly important since it is used to calculate several current and voltage parameters required by the National Electrical Code (NEC). Listing information is necessary for NEC testing requirements [NEC 90.7, 100, 110.3, 690.4].*

a) MODULE MANUFACTURER: This is the manufacturer's name (e.g. BP Solar, Evergreen, Solar World, Sharp, SunPower, Suntech etc.)

b) MODULE MODEL #: This is the model number on the listing label (e.g. BP175B, EGS185, SW175 Mono, ND-U230C1, SP225, STP175S, etc.)

c) MAXIMUM POWER-POINT CURRENT (I_{MP})

***Explanation**: The rated IMP is needed to calculate system operating current. This is the current of the module when operating at STC and maximum power.*

d) MAXIMUM POWER-POINT VOLTAGE (V_{MP})

***Explanation**: The rated V_{MP} is needed to calculate system operating voltage. This is the voltage of the module when operating at STC and maximum power.*

e) OPEN-CIRCUIT VOLTAGE (V_{OC})

***Explanation**: The rated V_{OC} is needed to calculate maximum system voltage specified in NEC 690.7.*

f) SHORT-CIRCUIT CURRENT (I_{SC})

***Explanation**: The rated I_{SC} is needed to calculate maximum current specified in NEC 690.8(A).*

g) MAXIMUM SERIES FUSE (OCPD)

***Explanation**: The maximum series fuse (OCPD) rating is needed to ensure that the proper overcurrent protection is provided for the modules and array wiring.*

h) MAXIMUM POWER (P_{MAX}) at Standard Test Conditions (STC is 1000W/m^2, 25˚C cell temp, & Air Mass 1.5)

***Explanation**: Maximum power at STC specifies the rated power of the PV module under simulated conditions.*

i) MAXIMUM SYSTEM VOLTAGE

***Explanation**: Maximum system voltage (often but not always 600 V_{dc}) is needed to show that the NEC 690.7 voltage does not exceed this value.*

Section 6. Array Information

This section defines the configuration of the PV array. PV arrays are generally made up of several modules in series, called "source circuits." These source circuits are often paralleled with multiple other source circuits to make up the entire dc generating unit called an "array." The last four items related to the PV array must be calculated and posted on a sign at the PV power source disconnect. The first two items a) and b) characterize the array design and provide the information necessary to calculate the four items needed to produce proper array identification for the PV power source sign discussed in Section 7 that is required at the site.

a) NUMBER OF MODULES IN SERIES_

***Explanation**: For simplicity, this diagram only addresses the most common configuration of PV modules—multiple modules in series. Although single module PV power sources exist, it is more common to see PV arrays configured with as many as 12 to 24 modules in series.*

b) NUMBER OF PARALLEL CIRCUITS

***Explanation**: Since single-phase inverters can be as large as 12 kW or more, and the largest PV source circuits are only about 2 to 5 kW, it is common for PV arrays to have two or more source circuits in parallel. From Example in Appendix A:*

Number of modules in series = 14
Number of parallel source circuits = 3
Total number of modules = 14 x 3 = 42

c) LOWEST EXPECTED AMBIENT TEMP

***Explanation**: Up through the 2008 edition, the NEC has not clearly defined "lowest expected ambient temperature." ASHRAE (American Society of Heating, Refrigeration, and Air Conditioning Engineers) has performed statistical analysis on weather data from the National Weather Service. These data include values for the mean extreme temperatures for the locations with temperature data. The mean extreme low temperature is the coldest expected temperature for a location. Half of the years on record have not exceeded this number, and the rest have exceeded this number. These data are supplied in the appendix for reference. The 2011 NEC includes an informational Note to 690.7 that specifies the use of the ASHRAE mean extreme value for lowest expected ambient temperature when calculating maximum system voltage.*

d) HIGHEST CONTINUOUS TEMP (ambient)

***Explanation**: Up through the 2011 edition, the NEC has not clearly defined "highest continuous ambient temperature." Continuous is defined in the NEC as a 3-hour period Article 100. ASHRAE (American Society of Heating, Refrigeration, and Air Conditioning Engineers) has performed statistical analysis on weather data from the National Weather Service. These data include design values of 0.4%, 1%, and 2% for each month signifying that the temperature only exceeds the recorded value up to the specified time for a given location with temperature data. The average for June, July, and August of the 2% value has been chosen by the Copper Development Association as the value that best represents a condition that would create the 3-hour continuous condition referred to in Article 100. Two percent of one month is about 14 hours. Since high temperatures usually last for several days in most locations, the **assumption is** that at least one or two 3-hour high temperature events will happen during a given month. These data are supplied in the appendix for reference. If a designer seeks a more conservative approach to temperature, the 0.4% data for hottest month of the year is an alternative value. 0.4% of one month is about 3 hours. Using the 0.4% value assumes that all 3 hours occur on the same day which would be the statistical worst case scenario. Both the 3-month average 2% data and the hottest single month 0.4% data are supplied in the appendix for reference.*

Section 7. Signs

a) PV POWER SOURCE

i) RATED MPP (MAXIMUM POWER-POINT) CURRENT
(sum of parallel source circuit operating currents)

Explanation: Rated MPP current is found by multiplying the module rated MPP current for a module series string by the number of source circuits in parallel.

From the example in Appendix A:

I_{MP} = *7.80 amps*

Number of source circuits in parallel = 3

7.80amps x *3 = 23.4 amps*

ii) RATED MPP (MAXIMUM POWER-POINT) VOLTAGE
(sum of series modules operating voltage in source circuit)

Explanation: Operating voltage is found by multiplying the module rated MPP voltage by the number of modules in a series source circuit.

From the example in Appendix A:

V_{MP} = *29.5 Volts*

Number of modules in series = 11

29.5 Volts x *11 = 325 Volts*

iii) MAXIMUM SYSTEM VOLTAGE [NEC 690.7]

Explanation: Maximum system voltage is calculated by multiplying the value of Voc on the listing label by the appropriate value on Table 690.7 in the NEC, and then multiplying that value by the number of modules in a series string. The table in the NEC is based on crystalline silicon modules and uses lowest expected ambient temperature at a site to derive the correction factor. Some modules do not have the same temperature characteristics as crystalline silicon so the manufacturer's instructions must be consulted to determine the proper way to correct voltage based on lowest expected ambient temperature. As of the 2008 NEC, the manufacturer's temperature correction factor must be used for all modules, regardless of construction, if the information is supplied. All known listed modules currently provide this information.

From the example in Appendix A:

Module V_{OC} = *37.0 Volts*

Rating temperature = 25°C

Number of Modules in Series = 11

Lowest expected ambient temperature (ASHRAE) = 1°C (Ontario, California)

Maximum System Voltage = V_{MAX} = V_{OC} x ***# of Modules in Series*** x ***Temperature Correction Factor***

Method 1*— Module Manufacturer's Temperature Correction Factor—Percentage Method*

Temperature Coefficient for V_{OC} = αV_{OC} = *-0.37%/C = -0.0037/C*

Temperature Correction Factor = 1 + α VOC (%) x *(TempLOW - TempRATING)*

= 1 + (-0.0037/C) x *(-1°C - 25°C)*

= 1 + 0.0962 = 1.0962

V_{MAX} = *37V* x *11* x *1.0962 = 446 Volts < 500Volts (compliant for a* $500V_{MAX}$ *inverter)*

Method 2— Module Manufacturer's Temperature Correction Factor—Voltage Method

Temperature Coefficient for V_{OC} = αV_{OC} = *137mV/C = 0.137 V/C*

Temperature Correction Factor = 1 + [αVOC (V) x *(TempLOW - TempRATED) ÷ VOC]*

= 1 + [0.137 V/C x *(-1°C - 25°C) ÷ 37V]*

= 1 + [5.206V ÷ 37V] = 1.0963

V_{MAX} = *37V* x *11* x *1.0963 = 446 Volts < 500Volts (compliant for a* $500V_{MAX}$ *inverter)*

Method 3—Table 690.7 Temperature Correction Factor

From row for ambient temperature = -1°C to -5°C 1.12

V_{MAX} = *37V* x *11* x *1.12 = 456 Volts < 500Volts (compliant for a* $500V_{MAX}$ *inverter)*

iv) MAXIMUM CIRCUIT CURRENT [NEC 690.8]

Explanation: The maximum circuit current is calculated by multiplying the rated Isc of the PV module by the number of source circuits operating in parallel, then multiplying this value by 125% to account for extended periods of sunlight above the tested solar intensity (rated irradiance = 1000

W/m²; maximum continuous irradiance = 1250 W/m²). The NEC in 690.53 asks for the short-circuit current in the 2005 and 2008 editions, but the 2008 edition clarifies in a Fine Print Note that the intended value is the maximum circuit current as defined in 690.8 (A) and is a worst-case continuous short-circuit current value.

From the example in Appendix A:

I_{SC} = *8.4 amps*

Number of source circuits in parallel = 3

8.4 amps x *3* x *1.25 = 31.5 amps*

b) WARNING SIGN REQUIRED BY NEC 690.17.

***Explanation**: Any time a switch can have the load side energized in the open position, a warning sign must be placed on the switch. This is nearly always true of the dc disconnect at the inverter. The line side of the switch is energized by the PV array, while the load side of the switch is often energized by input capacitors of the inverter. These capacitors can remain energized for five minutes or more as the bleed resistors dissipate the charge over time. The warning sign should read essentially as follows:*

WARNING: ELECTRICAL SHOCK HAZARD–LINE AND LOAD MAY BE ENERGIZED IN OPEN POSITION

c) Point of Connection Sign [NEC 690.54]
(To be placed on the Solar AC Disconnect and AC Point of Connection locations)

i) AC OUTPUT CURRENT

***Explanation**: The ac output current, or rated ac output current as stated in the NEC, at the point of connection is the maximum current of the inverter output at full power. When the rated current is not specifically called out in the specification sheets, it can be calculated by taking the maximum power of the inverter, at 40°, and dividing that value by the nominal voltage of the inverter.*

From the example in Appendix A:

Maximum Inverter Power = 7,000 watts

Nominal Voltage = 240 Volts

I_{RATED} = *7,000 W/ 240 V = 29.2 amps*

ii) NOMINAL AC VOLTAGE

***Explanation**: The nominal ac voltage, or nominal operating ac voltage as stated in the NEC, at the point of connection is the nominal voltage (not maximum or minimum) of the inverter output. It will be the same as the service voltage. Most residential inverters operate at 240 Volts.*

From the example in Appendix A:

Nominal Voltage = 240 Volts

d) PV System Disconnect Location Directory [NEC 690.56(B)]
(To be placed at service disconnect, if PV System Disconnect is not located at the same location)

***Explanation**: For first responders, it may not be readily apparent that a PV system has been installed on site. This directory indicates that a PV system has been installed on site and shows the disconnect location. This is only required if the PV disconnect is not immediately adjacent to the existing service disconnect.*

Section 8. Wiring and Overcurrent Protection

a) DC Wiring Systems:

Source-circuit conductors:

In Exposed Locations:

PV module interconnections are generally 90˚C wet-rated conductors NEC 690.31(A) FPN. The same conductor type is typically used for all home run conductors needed for source circuit conductors in exposed locations.

Allowable wire types are as follows:

- USE-2 single conductor cable for exposed locations. [NEC 690.31(B)]
- PV Wire or PV Cable as a single conductor for exposed locations (required for all ungrounded systems). [NEC 690.31(B), 690.3(0)(3)]

Explanation for the need for High Temperature Conductors: Typical temperature for PV modules in full sun at 20°C outdoor temperature is 50°C. This is a 30°C rise above outdoor temperatures. On the hottest day of the year, outdoor temperatures can reach a continuous temperature of 41°C in many hot locations throughout the United States. This means that the PV module could be operating at 71°C on the hottest day of the year (41°C + 30°C = 71°C). 75°C wire is insufficient for connection to a hot PV module under this condition.

To further support the concern over the high temperature of PV modules, a fine print note has been added to the 2005 NEC.

***"NEC 690.31 (A) FPN:** Photovoltaic modules operate at elevated temperatures when exposed to high ambient temperatures and to bright sunlight. These temperatures may routinely exceed 70°C (158°F) in many locations. Module interconnection conductors are available with insulation rated for wet locations and a temperature rating of 90°C (194°F) or greater."*

In Conduit on Rooftops:

THREE OPTIONS FOR SOURCE CIRCUIT CONDUCTOR TYPE (INSIDE CONDUIT CHOOSE ONE) THWN-2, XHHW-2 and RHW-2

Explanation: Conductors in conduit, when exposed to direct sunlight, must account for the higher temperatures caused by intense sunlight and the proximity of the roof. The 2005 NEC first recognized the issue of sunlit conduit in a fine print note in NEC 310.10.

*"**310.10 FPN No. 2**: Conductors installed in conduit exposed to direct sunlight in close proximity to rooftops have been shown, under certain conditions, to experience a temperature rise of 17°C (30°F) above ambient temperature on which the ampacity is based."*

The 2008 NEC codified this issue by classifying the temperatures based on the height above the roof surface. On residential roofs, where conduit typically is spaced between ½" and 3 ½" above the roof surface, the temperature adder is stated as 22°C above the ambient temperature according to NEC Table 310.15(B)(2)(c): in the 2008 NEC, and Table 310.15 (B)(3)(c) in the 2011 NEC. Using this adder, along with the ASHRAE 2% design data for the hottest location in the U.S. (Palm Springs, CA is 44°C), produces a design temperature of 66°C and correction factor of 0.58 for 90°C conductors based on NEC Table 690.31 and Table 310.16 in the 2008 NEC, and 310.15(B)(16) in the 2011 NEC. If nine conductors or less are in the exposed conduit (4 pairs of conductors or less), then the conduit fill correction factor is 0.7 according to NEC Table 310.15(B)(2)(a): in the 2008 NEC, and Table 310.15(B)(3)(a) in the 2011 NEC. Putting all these correction factors together means that the 30°C conductor ampacity can be calculated as follows:

If only two strings in parallel (no fuses):

$I_{30°C.} = I_{MAX}/0.58/0.7 = 2.46 \times I_{MAX}$

When $I_{SC} = 12.8$ *amps or less, then* $I_{MAX} = I_{SC} \times 1.25 = 16$ *amps or less.*

When $I_{MAX} = 16$ *Amps, then* $I_{30°C.} = 39.4$ *Amps (10 AWG, 90°C required (NEC Table 310.16))*

When $I_{SC} = 9.6$ *amps or less, then* $I_{MAX} = I_{SC} \times 1.25 = 12$ *amps or less.*

When $I_{MAX} = 12$ *Amps, then* $I_{30°C.} = 29.5$ *Amps (12 AWG, 90°C required (NEC Table 310.16))*

When $I_{SC} = 6.4$ *amps or less, then* $I_{MAX} = I_{SC} \times 1.25 = 8$ *amps or less.*

When $I_{MAX} = 8$ *Amps, then* $I_{30°C.} = 19.7$ *Amps (14 AWG, 90°C required (NEC Table 310.16))*

If fuses are needed to protect PV modules (most cases), a shortcut to choose a conductor of sufficient ampacity is to use the following calculation:

$I_{30°C.} = I_{FUSE}/0.58/0.7 = 2.46 \times I_{FUSE}$

When $I_{SC} = 6.4$ *amps or less, then* $I_{MAX} = I_{SC} \times 1.25 = 8$ *amps. The minimum overcurrent protective device (OCPD) as required by 690.8(B) is 10 amps (*$I_{FUSE} = I_{MAX} \times 1.25 = 10A$*).*

When $I_{FUSE} = 10$ *Amps, then* $I_{30°C.} = 2.46 \times 10A = 24.6$ *Amps (14 AWG, 90°C required (NEC Table 310.16) -10A fuse to protect the conductor)*

When $I_{SC} = 7.68$ *amps or less, then* $I_{MAX} = I_{SC} \times 1.25 = 9.6$ *amps. The minimum overcurrent protective device (OCPD) as required by NEC 690.8(B) is 12 amps (*$I_{FUSE} = I_{MAX} \times 1.25 = 12A$*).*

When $I_{FUSE} = 12$ *Amps, then* $I_{30°C.} = 2.46 \times 12A = 29.5$ *Amps (12 AWG, 90°C required (NEC Table 310.16) -12A fuse to protect the conductor)*

When I_{SC} = 9.6 amps or less, then I_{MAX} = I_{SC} x 1.25 = 12 amps. The minimum overcurrent protective device (OCPD) as required by 690.8(B) is 15 amps (I_{FUSE} = I_{MAX} x 1.25 = 15A).

When I_{FUSE} = 15 Amps, then $I_{30°C}$ = 2.46 x 15A = 36.9 Amps (10 AWG, 90°C required (NEC Table 310.16) -15A fuse to protect the conductor)

When I_{SC} = 12.8 amps or less, then I_{MAX} = I_{SC} x 1.25 = 16 amps. The minimum overcurrent protective device (OCPD) as required by 690.8(B) is 20 amps (I_{FUSE} = I_{MAX} x 1.25 = 20A).

When I_{FUSE} = 20 Amps, then $I_{30°C}$ = 2.46 x 15A = 49.2 Amps (8 AWG, 90°C required (NEC Table 310.16) -20A fuse to protect the conductor). However, the NEC in 240.4(B) allows a conductor with an ampacity that falls between two standard OCPD sizes to be rounded up to the next higher OCPD size. Since a 10 AWG conductor has an ampacity of 16.24A after conditions of use are applied (I_{10AWG} = 40A x 0.58 x 0.7 = 16.24), it is acceptable to protect a 10 AWG conductor with a 20A fuse according to NEC 240.4(B).

Since the highest I_{SC} module commonly available as of the writing of this guide is less than 12.8 amps, 10 AWG conductors will always work regardless of location in the U.S. as long as there are no more than 9 current carrying conductors in the conduit and the conduit is at least 0.5" above the roof surface. Smaller wire can be used according to the I_{SC} of the modules being used and the number of conductors in the conduit. These calculations are provided so that contractors and jurisdictions will not need to repeat these standard calculations over and over.

The following table (Conductor Sizing Chart) summarizes the minimum wire size and overcurrent devices for circuits with overcurrent devices from 10 amps up to 400 amps in the hottest U.S. location. Wire size is adjusted for number of conductors in the raceway and is listed as minimum in case size needs to be increased to account for voltage drop on long circuits.

Conductor Sizing Chart for Hottest U.S. Climate

For Sunlit Raceway 0.5"-3.5" from Roof and Max 2% Design Temp - 47°C

80% Duty Fuses		100% Duty Fuses		Minimum Conductor Size in Raceway		
Fuse Size	Max Rated I_{SC}	Fuse Size	Max Rated I_{SC}	Based on # of Cond. in Raceway (AWG)		
Amps	Amps	Amps	Amps	8 conductors	4-6 cond.	2 cond.
10	6.4	10	8	14	14	14
12	7.68	12	9.6	12	14	14
15	9.6	15	12	10	10	14
20	12.8	20	16	10	10	12
25	16	25	20	8	8	10
30	19.2	30	24	6	8	8
35	22.4	35	28	6	6	8
40	25.6	40	32	4	4	6
45	28.8	45	36	3	4	6
50	32	50	40	2	3	4
60	38.4	60	48	2	3	4
70	44.8	70	56	1	2	3
80	51.2	80	64	2/0	1/0	2
90	57.6	90	72	3/0	2/0	1
100	64	100	80	3/0	2/0	1/0
110	70.4	110	88	4/0	4/0	2/0
125	80	125	100	250MCM	3/0	2/0
150	96	150	120	300MCM	350MCM	3/0
175	112	175	140	400MCM	250MCM	4/0
200	128	200	160	2-3/0	400MCM	300MCM
225	144	225	180	2-4/0	500MCM	350MCM
250	160	250	200	2-250MCM	2-4/0	500MCM
300	192	300	240	2-300MCM	2-250MCM	600MCM
350	224	350	280	2-400MCM	2-350MCM	700MCM
400	256	400	320	2-500MCM	2-400MCM	1000MCM

b) AC Wiring Systems

Inverter Output Circuit overcurrent protection should be sized and protected according the manufacturer's directions. The circuit and corresponding overcurrent protection should be sized at a 125% of the maximum continuous output of the inverter [NEC 215.3 Overcurrent for Feeder Circuits, and NEC 690.8(A)(3) and 690.8(B)]. The 125 percent increase over the maximum Inverter Output Circuit current is to account for the standard listing of overcurrent devices to 80% of maximum circuit current for continuous duty. Listed inverters have a maximum allowable overcurrent protection device requirement that is printed on the listing label or found in the installation manual.

Explanation: For instance, the fictitious inverter in the example in Appendix A, the AI-7000 has a maximum continuous output of 29.2 amps and a maximum allowable overcurrent protection of 50 amps. This means that the minimum allowable overcurrent is 40 amps (29.2 amps x 1.25 = 36.5 amps—round up to the next standard size, which is 40 amps) and a maximum of 50 amps. Normally the minimum allowable breaker size is used since the panelboard supply breakers are constrained to 120% of the panelboard busbar rating.

From the example in Appendix A:
Inverter continuous output rating = 7000 Watts
Nominal inverter voltage = 240 Volts
Maximum operating current = 7000 Watts / 240 Volts = 29.2 Amps
Min. Inverter Output Circuit ampacity = 29.2 Amps x 1.25 = 36.5 Amps

Section 9. AC Point of Connection

NEC 705.12 (D) in the 2011 NEC and 690.64 (B) in the 2008 NEC covers the requirements for Point of Connection of the PV inverter to the building electrical system. The most common method of connection is through a dedicated circuit breaker to a panelboard busbar. The sum of the supply breakers feeding the busbar of a panel can be up to 120% of the busbar rating. Appendix C treats this subject in detail.

Explanation: A service panel containing a 200-amp busbar and a 200-amp main breaker will allow breakers totaling 120% of the busbar rating (240-amps). Since the main breaker is 200 amps, the PV breaker can be up to 40 amps without exceeding the 120% allowance. For a service panel with a 125-amp busbar and a 100-amp main breaker, this provision will allow up to a 50 amp breaker (125 amps x 1.2 = 150 amps; 150 amps - 100 amp main breaker = 50 amp PV breaker).

A provision in the 2005 NEC clarifies the fact that dedicated circuit breakers backfed from listed utility-interactive inverters do not need to be individually clamped to the panelboard busbars. This has always been the case, but many inspectors have employed the provisions of NEC 408.36(F) that the breaker be secured in place by an additional fastener. Utility-interactive inverters do not require this fastener since they are designed to shut down immediately should the dedicated breaker become disconnected from the bus bar under any condition. This provision is repeated in the 2008 NEC in a clear and concise statement:

"NEC 690.64(B)(6) *Fastening. Listed plug-in-type circuit breakers backfed from utility-interactive inverters complying with 690.60 shall be permitted to omit the additional fastener normally required by 408.36(D) for such applications."*

Since 690.64(B) and 705.12(D) are nearly identical in the 2008 NEC, the 2011 NEC references 705.12(D) in 690.64(B) so that all utility interactive inverter interconnections are covered in the same section. This will help consistency among other inverter-based technologies such as fuel cells, wind, and micro-turbines. The table below, or Table of NEC 690.64(B) AC Interconnection Options, shows the how the maximum current of the inverter (column 1) requires a minimum size OCPD (column 2), which requires a minimum size conductor (column 3), which requires a compatible busbar/main breaker combination in the panelboard (column 4). The way to understand column 4, minimum busbar/main breaker combinations is to look at the row that coincides with the particular breaker being selected (from column 2) and use any combination from column 4 found

on that row or higher in the table. For instance, a 40-amp inverter breaker works with a 200/200 panel combination, but it also works with a 125/100 combination found on the row above. The 40-amp breaker does not work on the 150/150 combination, since the largest breaker would be 30 amps for the 150/150 combination. Conductor size is listed as minimum in case size needs to be increased to account for voltage drop on long circuits.

Table of NEC 690.64(B) AC Interconnection Options

Maximum Inverter Current	Required Inverter OCPD Size	Minimum Conductor Size in Conduit	Minimum Busbar/Main Breaker Combinations (Busbar Amps/Main Amps)
64 Amps	80 Amps	4 AWG	400/400; 200/150
56 Amps	70 Amps	4 AWG	225/200; 250/225
48 Amps	60 Amps	6 AWG	300/300; 200/175
40 Amps	50 Amps	8 AWG	125/100; 150/125
36 Amps	45 Amps	8 AWG	225/225
32 Amps	40 Amps	8 AWG	200/200
24 Amps	30 Amps	10 AWG	150/150
16 Amps	20 Amps	12 AWG	100/100; 70/60
12 Amps	15 Amps	14 AWG	80/80

Section 10. Grounding

a) *System Grounding*

The NEC requires [NEC 690.41] that all systems operating above 50 volts have one conductor referenced to ground unless the system complies with the requirements of NEC 690.35 for ungrounded PV arrays. For most PV systems, this connection is made in the inverter during manufacture, not on site by the installer.

b) *Equipment Grounding*

The code also requires that all exposed non-current-carrying metal parts of module frames, equipment, and conductor enclosures be grounded regardless of system voltage [NEC 690.43]. The grounding of module frames has received significant attention in the last several years. Many jurisdictions, with a heightened concern over the issue, have dramatically restricted effective grounding options. A discussion on module frame grounding is found in Appendix D.

c) *Sizing of Grounding Conductors*

i) Equipment grounding conductor (EGC) sizing [NEC 690.45]
The size of the EGC is dependent on whether the system has ground fault protection (GFP) equipment or not. The provisions for GFP equipment are stated in NEC 690.5. Almost all inverters have GFP equipment integral to the inverter and require that the PV array be grounded at the inverter only.

(1) Systems with ground fault protection equipment
Size equipment grounding conductor according to NEC Table 250.122

(2) Systems without ground fault protection equipment
The NEC requires that equipment grounding conductors for systems without GFP equipment be sized for twice the minimum ampacity of the circuit conductors [NEC 690.45].

ii) System grounding conductor sizing

(1) AC System

Size grounding electrode conductor (GEC) according to NEC Table 250.66 Normally the site already has the conductor and electrode installed for the ac building wiring.

(2) DC System

Size grounding electrode conductor (GEC) according to NEC 250.166 This results in a minimum size of 8 AWG. The maximum size of the GEC is dependent upon the type of grounding electrode or the maximum size conductor in the dc system, whichever is smaller.

APPENDIX A: EXAMPLE SUBMITTALS

Step 1: Structural Review of PV Array Mounting System

Is the array to be mounted on a defined, permitted roof structure? ☒ **Yes** ☐ **No**

If No due to non-compliant roof or a ground mount, submit completed worksheet for the structure WKS1.

Roof Information:

1. Is the roofing type lightweight (Yes = composition, lightweight masonry, metal, etc…)
   Yes— composition
   If No, submit completed worksheet for roof structure WKS1 (No = heavy masonry, slate, etc…).
2. If a composition shingle roof, does the roof have a single roof covering? ☒ **Yes** ☐ **No**
   If No, submit completed worksheet for roof structure WKS1.
3. Provide method and type of weatherproofing roof penetrations (e.g. flashing, caulk).
   flashing

Mounting System Information:

1. Is the mounting structure an engineered product designed to mount PV modules, with no more than an 18" gap beneath the module frames? ☒ **Yes** ☐ **No** *If No, provide details of structural attachment certified by a design professional.*
2. For manufactured mounting systems, fill out information on the mounting system below:
   a. Mounting System Manufacturer UniRac Product Name and Model# SolarMount
   b. Total Weight of PV Modules and Rails 1780 lbs
   c. Total Number of Attachment Points 48
   d. Weight per Attachment Point (b ÷ c) 37 lbs (if greater than 45 lbs, see WKS1)
   e. Maximum Spacing Between Attachment Points on a Rail 48 inches (see product manual for maximum spacing allowed based on maximum design wind speed)
   f. Total Surface Area of PV Modules (square feet) 674 ft^2
   g. Distributed Weight of PV System on Roof (b ÷ f) 2.64 lbs/ft^2
   If distributed weight of the PV system is greater than 5 lbs/ft^2, see WKS1.

Step 2: Electrical Review of PV System (Calculations for Electrical Diagram)

In order for a PV system to be considered for an expedited permit process, the following must apply:

1. PV modules, utility-interactive inverters, and combiner boxes are identified for use in PV systems.
2. The PV array is composed of 4 series strings or less per inverter.
3. The total inverter capacity has a continuous ac power output 13,440 Watts or less
4. The ac interconnection point is on the load side of service disconnecting means (690.64(B)).
5. One of the standard electrical diagrams (E1.1, E1.1a, E1.1b, or E1.1c) can be used to accurately represent the PV system. Interactive PDF diagrams are available at www.solarabcs.org/permitting.

Fill out the standard electrical diagram completely. A guide to the electrical diagram is provided to help the applicant understand each blank to fill in. If the electrical system is more complex than the standard electrical diagram can effectively communicate, provide an alternative diagram with appropriate detail.

Site plan example 1

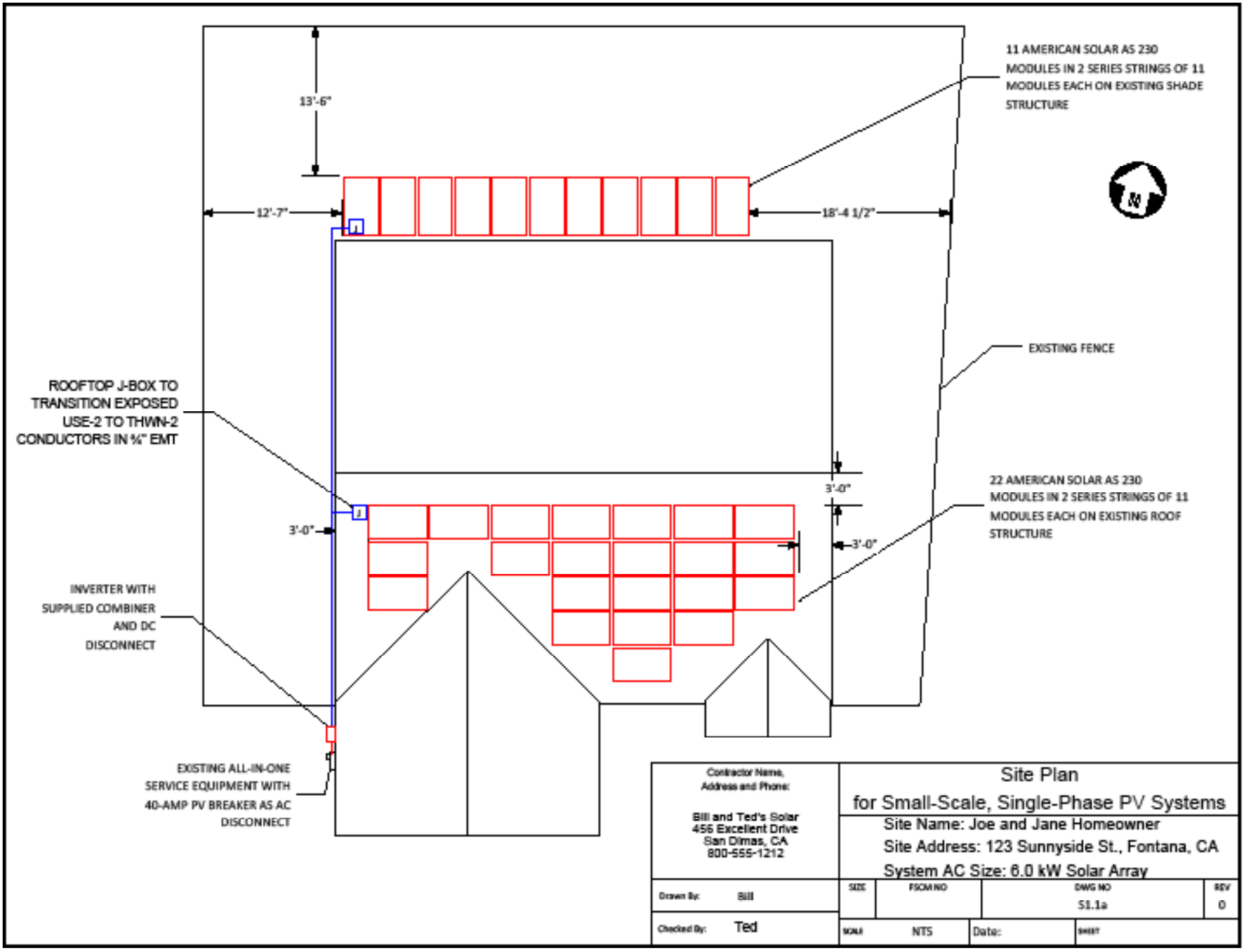
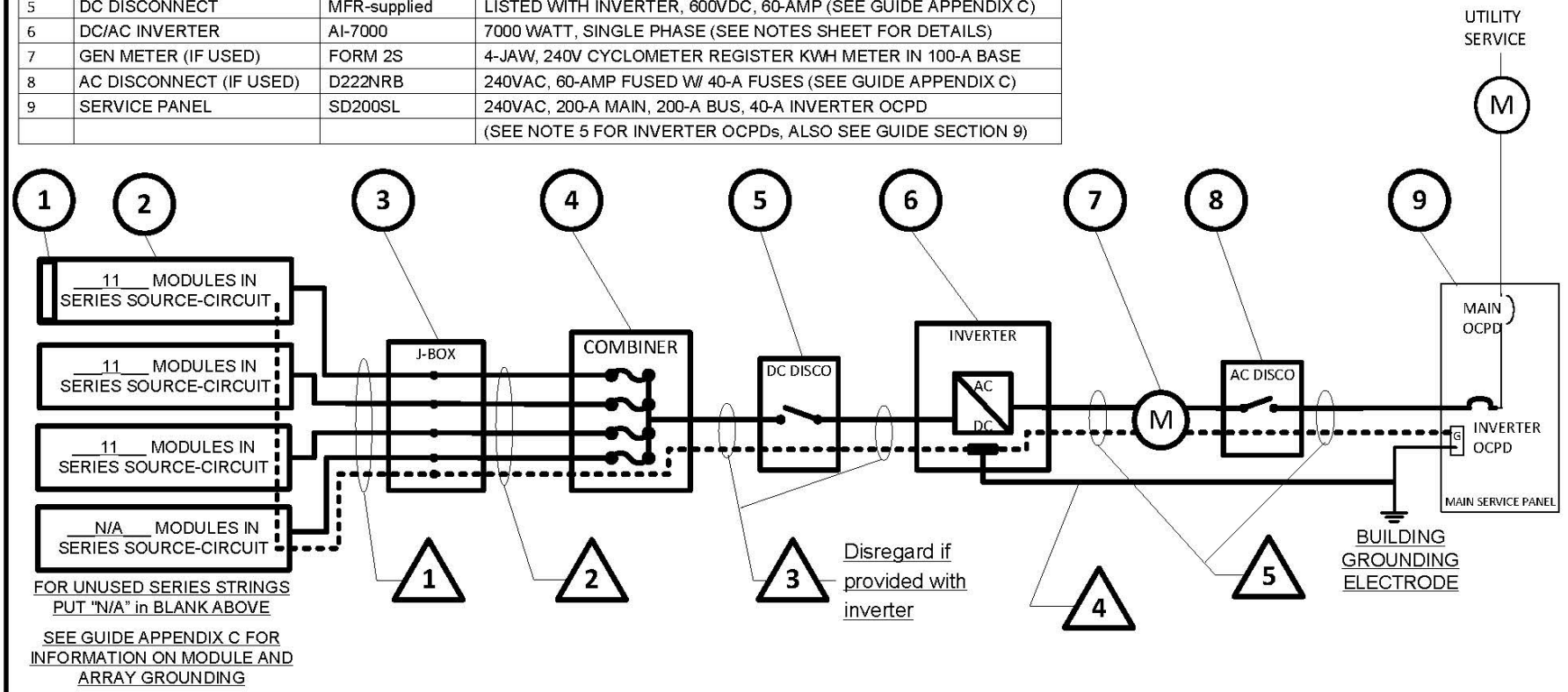


Diagram for Example 1

EQUIPMENT SCHEDULE			
TAG	DESCRIPTION	PART NUMBER	NOTES
1	SOLAR PV MODULE	AS 230	AMERICAN SOLAR, QUANTITY - 33 (SEE NOTES SHEET FOR DETAILS)
2	PV ARRAY	N/A	ARRAY IS 3 STRINGS WITH 11 MODULES PER SERIES STRING
3	J-BOX (IF USED)		6"x6"x4" NEMA 4, PVC JUNCTION BOX
4	COMBINER (IF USED)	MFR-supplied	15-A MAX FUSE W/15-A FUSES, 600VDC, 4-STRING MAX
5	DC DISCONNECT	MFR-supplied	LISTED WITH INVERTER, 600VDC, 60-AMP (SEE GUIDE APPENDIX C)
6	DC/AC INVERTER	AI-7000	7000 WATT, SINGLE PHASE (SEE NOTES SHEET FOR DETAILS)
7	GEN METER (IF USED)	FORM 2S	4-JAW, 240V CYCLOMETER REGISTER KWH METER IN 100-A BASE
8	AC DISCONNECT (IF USED)	D222NRB	240VAC, 60-AMP FUSED W/ 40-A FUSES (SEE GUIDE APPENDIX C)
9	SERVICE PANEL	SD200SL	240VAC, 200-A MAIN, 200-A BUS, 40-A INVERTER OCPD
			(SEE NOTE 5 FOR INVERTER OCPDs, ALSO SEE GUIDE SECTION 9)



CONDUIT AND CONDUCTOR SCHEDULE					
TAG	DESCRIPTION OR CONDUCTOR TYPE	COND. GAUGE	NUMBER OF CONDUCTORS	CONDUIT TYPE	CONDUIT SIZE
1	USE-2 ☒ or PV WIRE ☐	10 AWG	8 BLACK	N/A	N/A
	BARE COPPER EQ. GRD. COND. (EGC)	10 AWG	1 BARE CU	N/A	N/A
2	THWN-2 ☒ or XHHW-2 ☐ or RHW-2 ☐	10 AWG	4-R, 4-W, 1-G	EMT	¾"
3	THWN-2 ☒ or XHHW-2 ☐ or RHW-2 ☐	N/A	N/A	N/A	N/A
	INSULATED EGC	N/A	N/A		
4	DC GROUNDING ELECTRODE COND.	6 AWG	1 BARE CU	N/A	N/A
5	THWN-2 ☒ or XHHW-2 ☐ or RHW-2 ☐	8 AWG	1-R, 1-B, 1-W	EMT	¾"
	INSULATED EGC	10 AWG	1 GREEN		

Contractor Name, Address and Phone:

Bill and Ted's Solar
456 Excellent Drive
San Dimas, CA
800-555-1212

Drawn By: Bill

Checked By: Ted

One-Line Standard Electrical Diagram for Small-Scale, Single-Phase PV Systems

Site Name: Joe and Jane Homeowner
Site Address: 123 Sunnyside St., Fontana, CA
System AC Size: 6.1 kW Solar Array

SIZE	FSCM NO	DWG NO	REV
		E1.1	0

SCALE NTS | Date: | SHEET

Notes for Electrical Diagram for Example 1

PV MODULE RATINGS @ STC (Guide Section 5)

MODULE MAKE	AMERICAN SOLAR
MODULE MODEL	AS 230
MAX POWER-POINT CURRENT (I_{MP})	7.80 A
MAX POWER-POINT VOLTAGE (V_{MP})	29.5 V
OPEN-CIRCUIT VOLTAGE (V_{OC})	37.0 V
SHORT-CIRCUIT CURRENT (I_{SC})	8.40 A
MAX SERIES FUSE (OCPD)	15 A
MAXIMUM POWER (P_{MAX})	230 W
MAX VOLTAGE (TYP 600V_{DC})	600 V
VOC TEMP COEFF (mV/°C ☐ or %/°C ☒)	-0.37
IF COEFF SUPPLIED, CIRCLE UNITS	

NOTES FOR ALL DRAWINGS:

OCPD = OVERCURRENT PROTECTION DEVICE

NATIONAL ELECTRICAL CODE® REFERENCES SHOWN AS *(NEC XXX.XX)*

INVERTER RATINGS (Guide Section 4)

INVERTER MAKE	AMERICAN INVERTER
INVERTER MODEL	AI-7000
MAX DC VOLT RATING	500 V
MAX POWER @ 40°C	7000 W
NOMINAL AC VOLTAGE	240 V
MAX AC CURRENT	29 A
MAX OCPD RATING	50 A

SIGNS–SEE GUIDE SECTION 7

SIGN FOR DC DISCONNECT

PHOTOVOLTAIC POWER SOURCE	
RATED MPP CURRENT	19.6 A
RATED MPP VOLTAGE	430 V
MAX SYSTEM VOLTAGE	577 V
MAX CIRCUIT CURRENT	26.5 A

WARNING: ELECTRICAL SHOCK HAZARD–LINE AND LOAD MAY BE ENERGIZED IN OPEN POSITION

SIGN FOR INVERTER OCPD AND AC DISCONNECT (IF USED)

SOLAR PV SYSTEM AC POINT OF CONNECTION	
AC OUTPUT CURRENT	29 A
NOMINAL AC VOLTAGE	240 V

THIS PANEL FED BY MULTIPLE SOURCES (UTILITY AND SOLAR)

NOTES FOR ARRAY CIRCUIT WIRING (Guide Section 6 and 8 and Appendix E):

1.) LOWEST EXPECT AMBIENT TEMPERATURE BASED ON ASHRAE MINIMUM MEAN EXTREME DRY BULB TEMPERATURE FOR ASHRAE LOCATION MOST SIMILAR TO INSTALLATION LOCATION. LOWEST EXPECTED AMBIENT TEMP ___-1_°C

2.) HIGHEST CONTINUOUS AMBIENT TEMPERATURE BASED ON ASHRAE HIGHEST MONTH 2% DRY BULB TEMPERATURE FOR ASHRAE LOCATION MOST SIMILAR TO INSTALLATION LOCATION. HIGHEST CONTINUOUS TEMPERATURE __37_°C

2.) 2005 ASHRAE FUNDAMENTALS 2% DESIGN TEMPERATURES DO NOT EXCEED 47°C IN THE UNITED STATES (PALM SPRINGS, CA IS 44.1°C). FOR LESS THAN 9 CURRENT-CARRYING CONDUCTORS IN ROOF-MOUNTED SUNLIT CONDUIT AT LEAST 0.5" ABOVE ROOF AND USING THE OUTDOOR DESIGN TEMPERATURE OF 47°C OR LESS (ALL OF UNITED STATES),

a) 12 AWG, 90°C CONDUCTORS ARE GENERALLY ACCEPTABLE FOR MODULES WITH Isc OF 7.68 AMPS OR LESS WHEN PROTECTED BY A 12-AMP OR SMALLER FUSE.
b) 10 AWG, 90°C CONDUCTORS ARE GENERALLY ACCEPTABLE FOR MODULES WITH Isc OF 9.6 AMPS OR LESS WHEN PROTECTED BY A 15-AMP OR SMALLER FUSE.

NOTES FOR INVERTER CIRCUITS (Guide Section 8 and 9):

1) IF UTILITY REQUIRES A VISIBLE-BREAK SWITCH, DOES THIS SWITCH MEET THE REQUIREMENT? YES ☐ NO ☐ N/A ☒

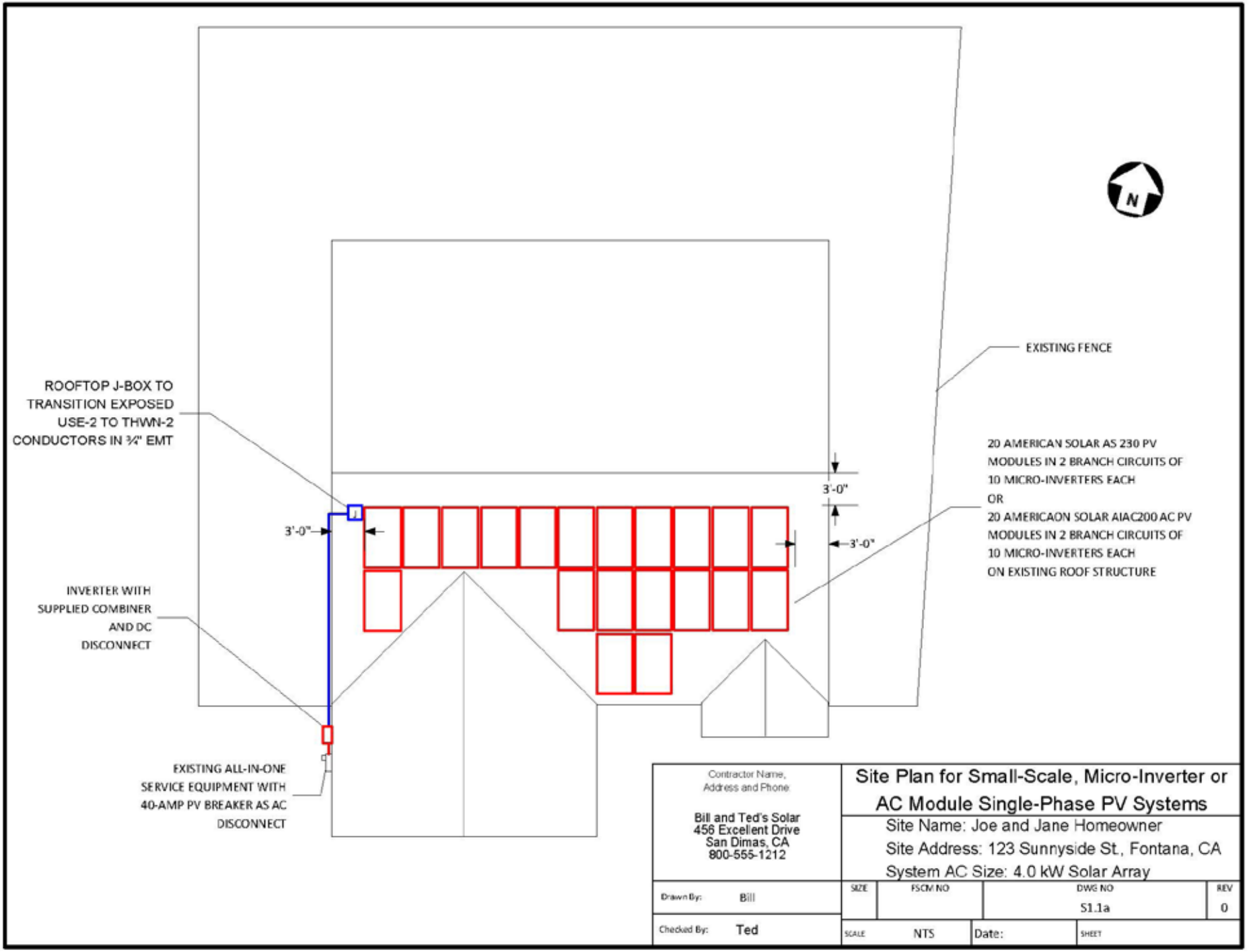
2) IF GENERATION METER REQUIRED, DOES THIS METER SOCKET MEET THE REQUIREMENT? YES ☐ NO ☐ N/A ☒

3) SIZE PHOTOVOLTAIC POWER SOURCE (DC) CONDUCTORS BASED ON MAX CURRENT ON NEC 690.53 SIGN OR OCPD RATING AT DISCONNECT

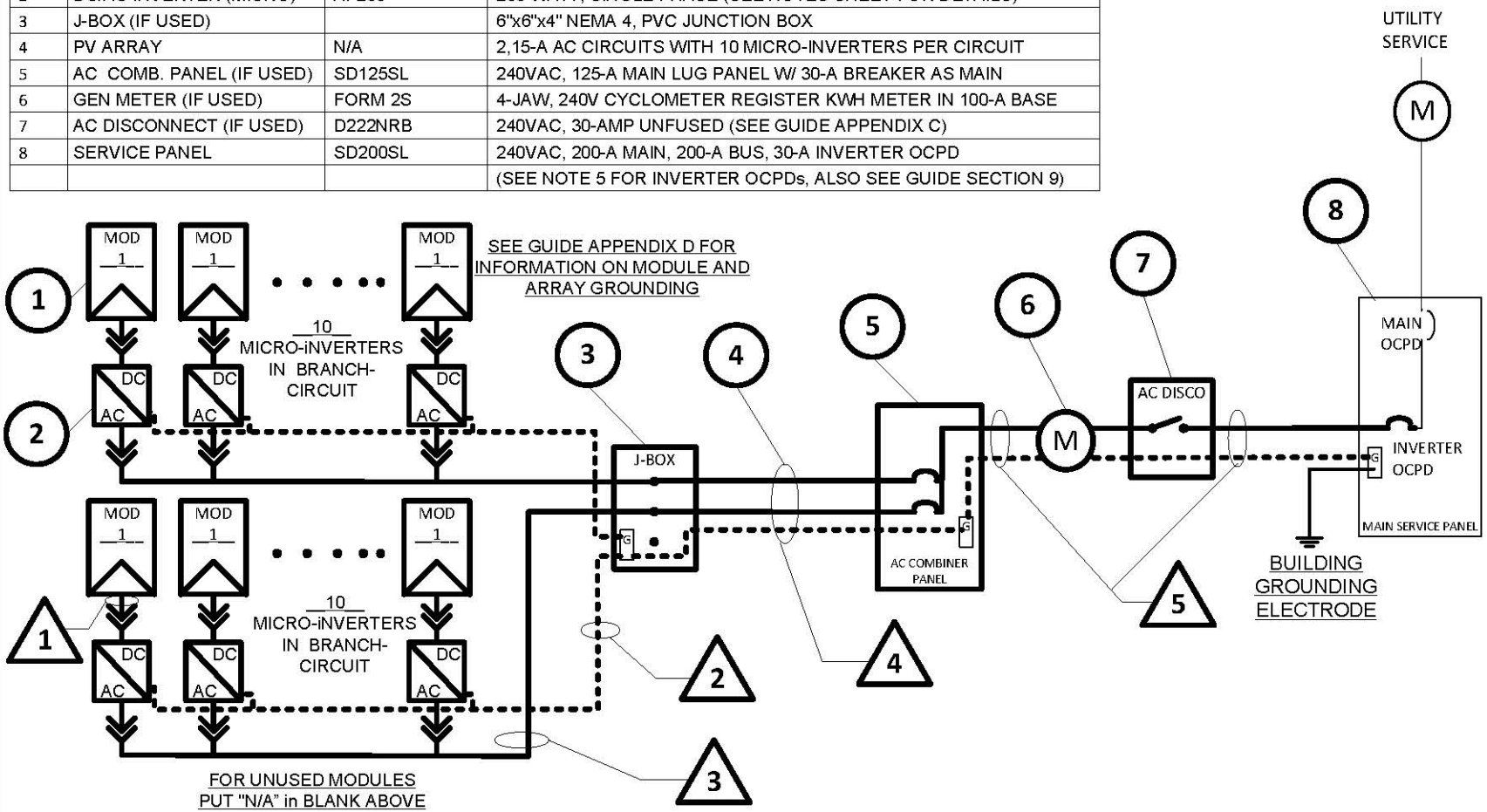
4) SIZE INVERTER OUTPUT CIRCUIT (AC) CONDUCTORS ACCORDING TO INVERTER OCPD AMPERE RATING. (See Guide Section 9)

5) TOTAL OF ___1___ INVERTER OCPD(s), ONE FOR EACH INVERTER. DOES TOTAL SUPPLY BREAKERS COMPLY WITH 120% BUSBAR EXCEPTION IN 690.64(B)(2)(a)? YES ☒ NO ☐

Contractor Name, Address and Phone: Bill and Ted's Solar, 456 Excellent Drive, San Dima, CA, 800-555-1212	Notes for One-Line Standard Electrical Diagram for Single-Phase PV Systems			
	Site Name: Joe and Jane Homeowner			
	Site Address: 123 Sunnyside St., Fontana, CA			
	System AC Size: 6.0 kW Solar Array			
Drawn By: Bill	SIZE	FSCM NO	DWG NO: E1.2	REV: 0
Checked By: Ted	SCALE: NTS	Date:	SHEET	


N
EXISTING FENCE
ROOFTOP J-BOX TO TRANSITION EXPOSED USE-2 TO THWN-2 CONDUCTORS IN ¾" EMT
20 AMERICAN SOLAR AS 230 PV MODULES IN 2 BRANCH CIRCUITS OF 10 MICRO-INVERTERS EACH
OR
20 AMERICAON SOLAR AIAC200 AC PV MODULES IN 2 BRANCH CIRCUITS OF 10 MICRO-INVERTERS EACH
ON EXISTING ROOF STRUCTURE
3'-0"
3'-0"
3'-0"
INVERTER WITH SUPPLIED COMBINER AND DC DISCONNECT
EXISTING ALL-IN-ONE SERVICE EQUIPMENT WITH 40-AMP PV BREAKER AS AC DISCONNECT
Contractor Name, Address and Phone
Bill and Ted's Solar
456 Excellent Drive
San Dimas, CA
800-555-1212
Site Plan for Small-Scale, Micro-Inverter or AC Module Single-Phase PV Systems
Site Name: Joe and Jane Homeowner
Site Address: 123 Sunnyside St., Fontana, CA
System AC Size: 4.0 kW Solar Array
Drawn By: Bill
Checked By: Ted
SIZE
FSCM NO
DWG NO
S1.1a
REV
0
SCALE
NTS
Date:
SHEET

EQUIPMENT SCHEDULE			
TAG	DESCRIPTION	PART NUMBER	NOTES
1	PV DC or AC MODULE	AS 230	AMERICAN SOLAR, QUANTITY - 20 (SEE NOTES SHEET FOR DETAILS)
2	DC/AC INVERTER (MICRO)	AI-200	200 WATT, SINGLE PHASE (SEE NOTES SHEET FOR DETAILS)
3	J-BOX (IF USED)		6"x6"x4" NEMA 4, PVC JUNCTION BOX
4	PV ARRAY	N/A	2,15-A AC CIRCUITS WITH 10 MICRO-INVERTERS PER CIRCUIT
5	AC COMB. PANEL (IF USED)	SD125SL	240VAC, 125-A MAIN LUG PANEL W/ 30-A BREAKER AS MAIN
6	GEN METER (IF USED)	FORM 2S	4-JAW, 240V CYCLOMETER REGISTER KWH METER IN 100-A BASE
7	AC DISCONNECT (IF USED)	D222NRB	240VAC, 30-AMP UNFUSED (SEE GUIDE APPENDIX C)
8	SERVICE PANEL	SD200SL	240VAC, 200-A MAIN, 200-A BUS, 30-A INVERTER OCPD
			(SEE NOTE 5 FOR INVERTER OCPDs, ALSO SEE GUIDE SECTION 9)



CONDUIT AND CONDUCTOR SCHEDULE					
TAG	DESCRIPTION OR CONDUCTOR TYPE	COND.	NUMBER OF	CONDUIT	CONDUIT
		GAUGE	CONDUCTORS	TYPE	SIZE
1	USE-2 ☐ or PV WIRE ☐	MFG	MFG Cable	N/A	N/A
2	GEC ☒ EGC ☒ X ALL THAT APPLY	6 AWG	1 BARE CU	N/A	N/A
3	EXTERIOR CABLE LISTED W/ INV.	MFG	MFG Cable	N/A	N/A
4	THWN-2 ☒ or XHHW-2 ☐ or RHW-2 ☐	12 AWG	2-B, 2-R, 2-W	EMT	¾"
	GEC ☒ EGC ☒ X ALL THAT APPLY	8 AWG	1 GREEN	SAME	SAME
	NO DC GEC IF 690.35 SYSTEM				
5	THWN-2 ☒ or XHHW-2 ☐ or RHW-2 ☐	10 AWG	1-R, 1-B, 1-W	EMT	¾"
	GEC ☒ EGC ☒ X ALL THAT APPLY	8 AWG	1 GREEN	SAME	SAME

Contractor Name, Address and Phone:

Bill and Ted's Solar
456 Excellent Drive
San Dimas, CA
800-555-1212

One-Line Standard Electrical Diagram for Micro-Inverter or AC Module PV Systems

Site Name: John and Jane Homeowner
Site Address: 123 Sunnyside St., Fontana, CA
System AC Size: 4.0 KW

Drawn By:	Bill	SIZE	FSCM NO	DWG NO	REV
Checked By:	Ted			E1.1a	0
		SCALE	NTS	Date:	SHEET

PV MODULE RATINGS @ STC (Guide Section 5)

MODULE MAKE	AMERICAN SOLAR
MODULE MODEL	AS 230
MAX POWER-POINT CURRENT (I_{MP})	7.80 A
MAX POWER-POINT VOLTAGE (V_{MP})	29.5 V
OPEN-CIRCUIT VOLTAGE (V_{OC})	37.0 V
SHORT-CIRCUIT CURRENT (I_{SC})	8.40 A
MAX SERIES FUSE (OCPD)	15 A
MAXIMUM POWER (P_{MAX})	230 W
MAX VOLTAGE (TYP 600V_{DC})	600 V
VOC TEMP COEFF (mV/^{0}C ☐ or %/^{0}C ☒)	-0.37
IF COEFF SUPPLIED, CIRCLE UNITS	

NOTES FOR ALL DRAWINGS:

OCPD = OVERCURRENT PROTECTION DEVICE

NATIONAL ELECTRICAL CODE® REFERENCES SHOWN AS *(NEC XXX.XX)*

INVERTER RATINGS (Guide Section 4)

INVERTER MAKE	AMERICAN INVERTER
INVERTER MODEL	AI-200
MAX DC VOLT RATING	60 V
MAX POWER @ 40^{0}C	200 W
NOMINAL AC VOLTAGE	240 V
MAX AC CURRENT	0.83 A
MAX OCPD RATING	15 A

SIGNS--SEE GUIDE SECTION 7

SIGN FOR DC DISCONNECT

No sign necessary since 690.51 marking on PV module covers needed information

SIGN FOR INVERTER OCPD AND AC DISCONNECT (IF USED)

SOLAR PV SYSTEM AC POINT OF CONNECTION	
AC OUTPUT CURRENT	24 A
NOMINAL AC VOLTAGE	240 V

THIS PANEL FED BY MULTIPLE SOURCES (UTILITY AND SOLAR)

NOTES FOR ARRAY CIRCUIT WIRING (Guide Section 6 and 8 and Appendix E):

1.) LOWEST EXPECT AMBIENT TEMPERATURE BASED ON ASHRAE MINIMUM MEAN EXTREME DRY BULB TEMPERATURE FOR ASHRAE LOCATION MOST SIMILAR TO INSTALLATION LOCATION. LOWEST EXPECTED AMBIENT TEMP ___-1_ ^{0}C

2.) HIGHEST CONTINUOUS AMBIENT TEMPERATURE BASED ON ASHRAE HIGHEST MONTH 2% DRY BULB TEMPERATURE FOR ASHRAE LOCATION MOST SIMILAR TO INSTALLATION LOCATION. HIGHEST CONTINUOUS TEMPERATURE __37_ ^{0}C

2.) 2009 ASHRAE FUNDAMENTALS 2% DESIGN TEMPERATURES DO NOT EXCEED 47^{0}C IN THE UNITED STATES (PALM SPRINGS, CA IS 44.1^{0}C). FOR LESS THAN 9 CURRENT-CARRYING CONDUCTORS IN ROOF-MOUNTED SUNLIT CONDUIT AT LEAST 0.5" ABOVE ROOF AND USING THE OUTDOOR DESIGN TEMPERATURE OF 47^{0}C OR LESS (ALL OF UNITED STATES),

a) 12 AWG, 90^{0}C CONDUCTORS ARE GENERALLY ACCEPTABLE FOR MODULES WITH Isc OF 7.68 AMPS OR LESS WHEN PROTECTED BY A 12-AMP OR SMALLER FUSE.

b) 10 AWG, 90^{0}C CONDUCTORS ARE GENERALLY ACCEPTABLE FOR MODULES WITH Isc OF 9.6 AMPS OR LESS WHEN PROTECTED BY A 15-AMP OR SMALLER FUSE.

NOTES FOR INVERTER CIRCUITS (Guide Section 8 and 9):

1) IF UTILITY REQUIRES A VISIBLE-BREAK SWITCH, DOES THIS SWITCH MEET THE REQUIREMENT? YES ☒ NO ☐ N/A ☐

2) IF GENERATION METER REQUIRED, DOES THIS METER SOCKET MEET THE REQUIREMENT? YES ☐ NO ☐ N/A ☒

3) SIZE PHOTOVOLTAIC POWER SOURCE (DC) CONDUCTORS BASED ON MAX CURRENT ON NEC 690.53 SIGN OR OCPD RATING AT DISCONNECT

4) SIZE INVERTER OUTPUT CIRCUIT (AC) CONDUCTORS ACCORDING TO INVERTER OCPD AMPERE RATING. (See Guide Section 9)

5) TOTAL OF ___2___ INVERTER OUTPUT CIRCUIT OCPD(s), ONE FOR EACH MICRO-INVERTER CIRCUIT. DOES TOTAL SUPPLY BREAKERS COMPLY WITH 120% BUSBAR EXCEPTION IN 690.64(B)(2)(a)? YES☒ NO☐

Contractor Name, Address and Phone:

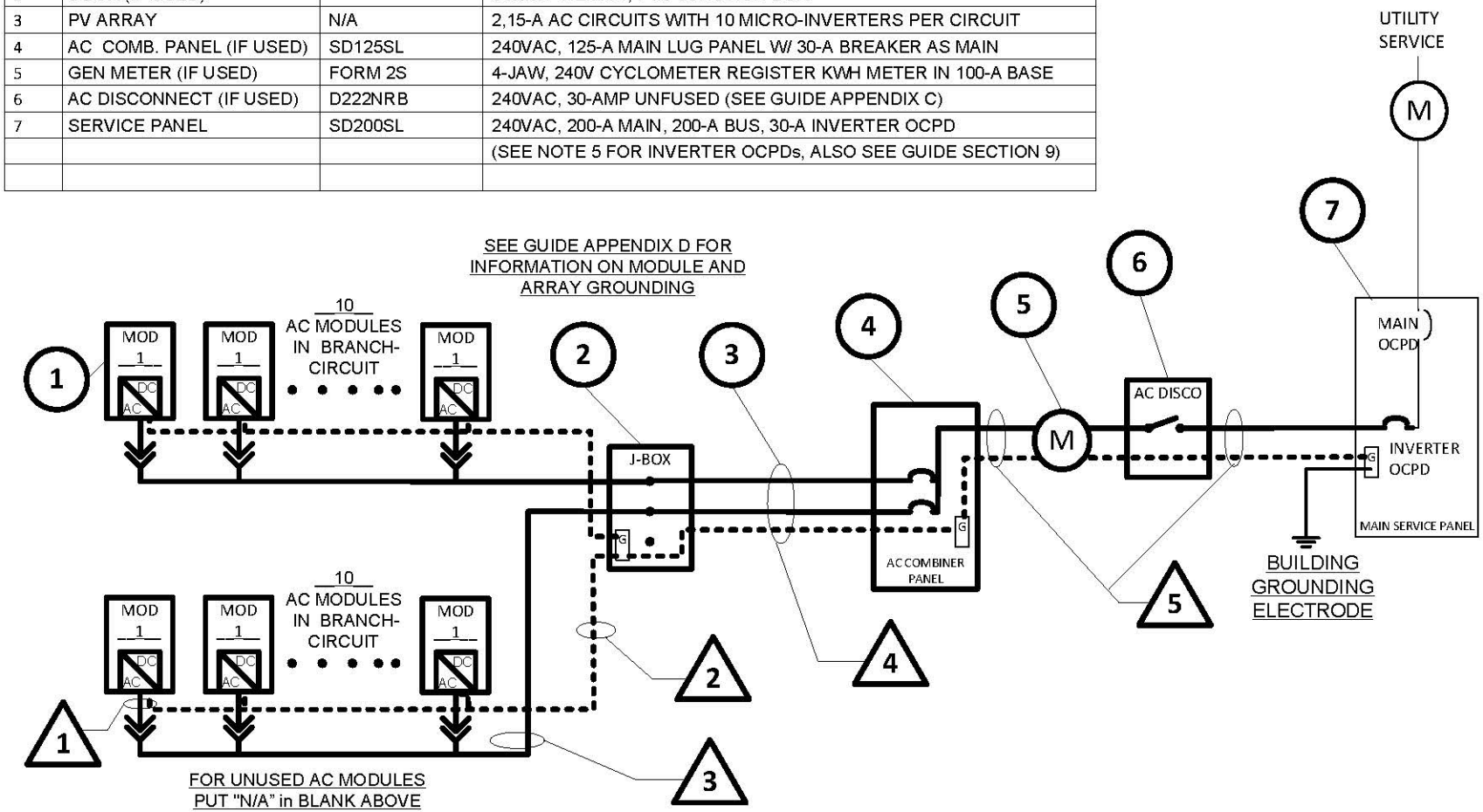
Bill and Ted's Solar
456 Excellent Drive
San Dimas, CA
800-555-1212

Notes for One-Line Standard Electrical Diagram for Single-Phase PV Systems

Site Name: Joe and Jane Homeowner
Site Address: 123 Sunnyside St., Fontana, CA
System AC Size: 4.0 kW Solar Array

Drawn By: Bill	SIZE	FSCM NO	DWG NO E1.2a	REV 0
Checked By: Ted	SCALE NTS	Date:	SHEET	

EQUIPMENT SCHEDULE			
TAG	DESCRIPTION	PART NUMBER	NOTES
1	AC MODULE	ASAC 200	AMERICAN SOLAR, QUANTITY - 20 (SEE NOTES SHEET FOR DETAILS)
2	J-BOX (IF USED)		6"x6"x4" NEMA 4, PVC JUNCTION BOX
3	PV ARRAY	N/A	2,15-A AC CIRCUITS WITH 10 MICRO-INVERTERS PER CIRCUIT
4	AC COMB. PANEL (IF USED)	SD125SL	240VAC, 125-A MAIN LUG PANEL W/ 30-A BREAKER AS MAIN
5	GEN METER (IF USED)	FORM 2S	4-JAW, 240V CYCLOMETER REGISTER KWH METER IN 100-A BASE
6	AC DISCONNECT (IF USED)	D222NRB	240VAC, 30-AMP UNFUSED (SEE GUIDE APPENDIX C)
7	SERVICE PANEL	SD200SL	240VAC, 200-A MAIN, 200-A BUS, 30-A INVERTER OCPD
			(SEE NOTE 5 FOR INVERTER OCPDs, ALSO SEE GUIDE SECTION 9)



CONDUIT AND CONDUCTOR SCHEDULE					
TAG	DESCRIPTION OR CONDUCTOR TYPE	COND. GAUGE	NUMBER OF CONDUCTORS	CONDUIT TYPE	CONDUIT SIZE
1	USE-2 ☐ or PV WIRE ☐	MFG	MFG Cable	N/A	N/A
2	GEC ☒ EGC ☒ X ALL THAT APPLY	6 AWG	1 BARE CU	N/A	N/A
3	EXTERIOR CABLE LISTED W/ INV.	MFG	MFG Cable	N/A	N/A
4	THWN-2 ☒ or XHHW-2 ☐ or RHW-2 ☐	12 AWG	2-B, 2-R, 2-W	EMT	¾"
	GEC ☒ EGC ☒ X ALL THAT APPLY	8 AWG	1 GREEN	SAME	SAME
	NO DC GEC IF 690.35 SYSTEM				
5	THWN-2 ☒ or XHHW-2 ☐ or RHW-2 ☐	10 AWG	1-R, 1-B, 1-W	EMT	¾"
	GEC ☒ EGC ☒ X ALL THAT APPLY	8 AWG	1 GREEN	SAME	SAME

Contractor Name, Address and Phone:

Bill and Ted's Solar
456 Excellent Drive
San Dimas, CA
800-555-1212

One-Line Standard Electrical Diagram for AC Module PV Systems

Site Name: John and Jane Homeowner
Site Address: 123 Sunnyside St., Fontana, CA
System AC Size: 4.0 KW

Drawn By:	Bill	SIZE	FSCM NO	DWG NO	REV
				E1.1b	0
Checked By:	Ted	SCALE	NTS	Date:	SHEET

NOTES FOR ALL DRAWINGS:

OCPD = OVERCURRENT PROTECTION DEVICE

NATIONAL ELECTRICAL CODE® REFERENCES SHOWN AS *(NEC XXX.XX)*

AC MODULE RATINGS (Guide Appendix C)

AC MODULE MAKE	AMERICAN INVERTER
AC MODULE MODEL	AIAC-200
NOMINAL OPERATING AC VOLTAGE	240 V
NOMINAL OPERATING AC FREQUENCY	60 HZ
MAXIMUM AC POWER	200 W
MAXIMUM AC CURRENT	0.83 A
MAXIMUM OCPD RATING	15 A

SIGNS--SEE GUIDE SECTION 7

SIGN FOR DC DISCONNECT

N/A since no dc wiring

SIGN FOR INVERTER OCPD AND AC DISCONNECT (IF USED)

SOLAR PV SYSTEM AC POINT OF CONNECTION	
AC OUTPUT CURRENT	24 A
NOMINAL AC VOLTAGE	240 V
THIS PANEL FED BY MULTIPLE SOURCES (UTILITY AND SOLAR)	

NOTES FOR ARRAY CIRCUIT WIRING (Guide Section 6 and 8 and Appendix F):

1.) LOWEST EXPECT AMBIENT TEMPERATURE BASED ON ASHRAE MINIMUM MEAN EXTREME DRY BULB TEMPERATURE FOR ASHRAE LOCATION MOST SIMILAR TO INSTALLATION LOCATION. LOWEST EXPECTED AMBIENT TEMP ___-1_°C

2.) HIGHEST CONTINUOUS AMBIENT TEMPERATURE BASED ON ASHRAE HIGHEST MONTH 2% DRY BULB TEMPERATURE FOR ASHRAE LOCATION MOST SIMILAR TO INSTALLATION LOCATION. HIGHEST CONTINUOUS TEMPERATURE __37_°C

2.) 2009 ASHRAE FUNDAMENTALS 2% DESIGN TEMPERATURES DO NOT EXCEED 47°C IN THE UNITED STATES (PALM SPRINGS, CA IS 44.1°C). FOR 6 OR LESS CURRENT-CARRYING CONDUCTORS IN ROOF-MOUNTED SUNLIT CONDUIT AT LEAST 0.5" ABOVE ROOF AND USING THE OUTDOOR DESIGN TEMPERATURE OF 47°C OR LESS (ALL OF UNITED STATES),

a) 12 AWG, 90°C CONDUCTORS ARE GENERALLY ACCEPTABLE FOR AC MODULES INVERTER OUTPUT CIRCUITS WITH 12 AMPS OR LESS WHEN PROTECTED BY A 15-AMP OR SMALLER OCPD.

b) 10 AWG, 90°C CONDUCTORS ARE GENERALLY ACCEPTABLE FOR AC MODULES INVERTER OUTPUT CIRCUITS WITH 16 AMPS OR LESS WHEN PROTECTED BY A 20-AMP OR SMALLER OCPD.

NOTES FOR INVERTER CIRCUITS (Guide Section 8 and 9):

1) IF UTILITY REQUIRES A VISIBLE-BREAK SWITCH, DOES THIS SWITCH MEET THE REQUIREMENT? YES ☒ NO ☐ N/A ☐

2) IF GENERATION METER REQUIRED, DOES THIS METER SOCKET MEET THE REQUIREMENT? YES ☐ NO ☐ N/A ☒

3) SIZE PHOTOVOLTAIC POWER SOURCE (DC) CONDUCTORS BASED ON MAX CURRENT ON NEC 690.53 SIGN OR OCPD RATING AT DISCONNECT (N/A)

4) SIZE INVERTER OUTPUT CIRCUIT (AC) CONDUCTORS ACCORDING TO INVERTER OCPD AMPERE RATING. (See Guide Section 9)

5) TOTAL OF ___2___ INVERTER OUTPUT CIRCUIT OCPD(s), ONE FOR EACH AC MODULE CIRCUIT. DOES TOTAL SUPPLY BREAKERS COMPLY WITH 120% BUSBAR EXCEPTION IN 690.64(B)(2)(a)? YES☒ NO☐

Contractor Name, Address and Phone:

Bill and Ted's Solar
456 Excellent Drive
San Dimas, CA
800-555-1212

Notes for One-Line Standard Electrical Diagram for Single-Phase PV Systems

Site Name: Joe and Jane Homeowner
Site Address: 123 Sunnyside St., Fontana, CA
System AC Size: 4.0 kW Solar Array

Drawn By: Bill	SIZE	FSCM NO	DWG NO E1.2b	REV 0
Checked By: Ted	SCALE NTS	Date:	SHEET	

APPENDIX B: STRUCTURAL

B.1 Structure Worksheet—WKS1

If array is roof mounted

This section is for evaluating roof structural members that are site built. This includes rafter systems and site built trusses. Manufactured truss and roof joist systems, when installed with proper spacing, meet the roof structure requirements covered in item 2 below.

1. Roof construction: ☐ **Rafters** ☐ **Trusses** ☐ **Other**: _____
2. Describe site-built rafter or or site-built truss system.
    a. Rafter Size: ___ x ___ inches
    b. Rafter Spacing: _____ inches
    c. Maximum unsupported span: _____ feet, _____ inches
    d. Are the rafters over-spanned? (see the IRC span tables in **B.2**.) ☐ **Yes** ☐ **No**
    e. If ***Yes***, complete the rest of this section.
3. If the roof system has
    a. over-spanned rafters or trusses,
    b. the array over 5 lbs/ft^2 on any roof construction, or
    c. the attachments with a dead load exceeding 45 lbs per attachment;

    it is recommended that you provide one of the following:
        i. A framing plan that shows details for how you will strengthen the rafters using the supplied span tables in B.2.
        ii. Confirmation certified by a design professional that the roof structure will support the array.

If array is ground mounted:

1. Show array supports, framing members, and foundation posts and footings.
2. Provide information on mounting structure(s) construction. If the mounting structure is unfamiliar to the local jurisdiction and is more than six (6) feet above grade, it may require engineering calculations certified by a design professional.
3. Show detail on module attachment method to mounting structure.

B.2 Span Tables

A framing plan is required only if the combined weight of the PV array exceeds 5 pounds per square foot (PSF or lbs/ft^2) or the existing rafters are over-spanned. The following span tables from the 2009 International Residential Code (IRC) can be used to determine if the rafters are over-spanned. For installations in jurisdictions using different span tables, follow the local tables.

Span Table R802.5.1(1),

Use this table for rafter spans that have conventional light-weight dead loads and do not have a ceiling attached.

10 PSF Dead Load Roof live load = 20 psf, ceiling not attached to rafters, L/Δ=180							
Rafter Size			2 x 4	2 x 6	2 x 8	2 x 10	2 x 12
Spacing (inches)	Species	Grade	The measurements below are in feet-inches (e.g. 9-10 = 9 feet, 10 inches).				
16	Douglas Fir-larch	#2 or better	9-10	14-4	18-2	22-3	25-9
16	Hem-fir	#2 or better	9-2	14-2	17-11	21-11	25-5
24	Douglas Fir-larch	#2 or better	8-0	11-9	14-10	18-2	21-0
24	Hem-fir	#2 or better	7-11	11-7	14-8	17-10	20-9

Use this table for rafter spans that have heavy dead loads and do not have a ceiling attached.

20 PSF Dead Load Roof live load = 20 psf, ceiling not attached to rafters, L/Δ=180							
Rafter Size			2 x 4	2 x 6	2 x 8	2 x 10	2 x 12
Spacing (inches)	Species	Grade	The measurements below are in feet-inches (e.g. 9-10 = 9 feet, 10 inches).				
16	Douglas Fir-larch	#2 or better	8-6	12-5	15-9	19-3	22-4
16	Hem-fir	#2 or better	8-5	12-3	15-6	18-11	22-0
24	Douglas Fir-larch	#2 or better	6-11	10-2	12-10	15-8	18-3
24	Hem-fir	#2 or better	6-10	10-0	12-8	15-6	17-11

APPENDIX C: MICRO-INVERTERS AND AC MODULES

General

Micro-inverters and ac modules convert PV dc power to ac power on a module by module basis. The output of the PV module is fed directly into the inverter so that the majority, or all, of the field wiring is ac rather than dc. This array design has several advantages including the fact that, when the utility service is shut down, the only voltage that remains in the system is the low dc voltage that the module produces. In the 1999 NEC section 690.6, Alternating-Current (ac) Modules, was added to the electrical code. While a few products existed at that time, only recently has the number of installations increased sharply.

The fundamental difference between micro-inverters and ac modules is that an ac module does not have to meet the requirements for the dc side of a PV system.The dc wiring is considered internal to the unit and covered by the product listing process (the NEC defines the requirements of an ac module in NEC 690.6(A)). The product listing requirements for the inverter portion of an ac module is covered in the standard, UL 1741, entitled Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources. Article 110.3(B) requires that all equipment is installed according to the product instructions. Jurisdictions are encouraged to approve products that have been certified by a Nationally Recognized Testing Laboratory (NRTL) that is approved by OSHA to test the appropriate product evaluation standards (primarily UL1703 and UL1741) in Article 90.7. Since a micro-inverter is not covered by the 690.6(A) provision, it must comply with the requirements for the dc side of a PV system. In essence, a micro-inverter system is simply a very small PV system with a one (or two) module PV array.

Common code issues for micro-inverters and ac modules

Conductors used for micro-inverters and ac modules

Cables and conductors connected to micro-inverters and ac modules have been called into question by various jurisdictions over the years. Since the wiring for these types of PV systems are often concealed under the PV module, 690.34 applies for connections that require access under the module. 690.34 states, *Access to Boxes. Junction, pull, and outlet boxes located behind modules or panels shall be so installed that the wiring contained in them can be rendered accessible directly or by displacement of a module(s) or panel(s) secured by removable fasteners and connected by a flexible wiring system.* This requires that a flexible wiring system be used to provide for access and servicing. The most common cable type used for the ac side of these systems is Type TC-ER, which is tray cable with extra reinforcing and protection. TC-ER when rated sunlight resistance meets all the requirements of 690.31(D), Flexible Cords and Cables. 690.31(D) cables must be rated for extra hard usage, for outdoor use, for wet locations, and for sunlight resistance, and meet the requirements of article 400. While Type TC-ER is not specifically mentioned in article 400, 400.4 states, *"400.4 Types. Flexible cords and flexible cables shall conform to the description in Table 400.4. Types of flexible cords and flexible cables other than those listed in the table shall be the subject of special investigation."* Since the cable is part of the overall equipment listing, the cable, connectors, and cable to the junction box where the wiring method is transitioned to standard wiring methods is covered by the equipment listing and subjected to special investigation. Proper support of the cable is an important safety consideration and the installation instruction should provide detailed information on how to properly support the cable between modules and to the transitional junction box.

Another common issue for micro-inverters and ac modules is a shared OCPD for multiple units. Typical string inverters will each require a dedicated OCPD, which would be a burdensome requirement for a system with many micro-inverters or ac modules. This feature allows up to 15 or 20 outputs to be paralleled with field wiring and protected by a single 15A or 20A breaker which does not need to be located at the array. Product docu-

mentation will describe the maximum number of units that could be paralleled in this manner on a single OCPD. This configuration is still be compatible with 690.64(B)(1) in that individual inverters/modules can still be disconnected individually, as described below.

Since the remaining requirements differ between micro-inverters and ac modules, the NEC requirements will be covered separately in the following sections.

AC Module Systems in the NEC

Ac modules are defined by the NEC as a complete package of PV parts and electronics, independent of mounting structure, which produces ac power. 690.6 covers the installation requirements of ac modules. 690.6(C) permits a single disconnecting means to provide disconnect for multiple inverters on the same circuit. 690.6(D) permits one device to provide ground-fault protection for all the ac modules a single circuit. Note that this is not a requirement, but rather an allowance. An installer might want to provide this capability with a typical 15- or 20-amp GFCI breaker. While this sounds like a good idea, and appears to comply with 690.6(D), there are no GFCI breakers on the market, as of the writing of this document, that are listed for bidirectional power flow. Laboratory tests have shown that some GFCI breakers can be damaged while backfeeding power. A message to plan checkers and inspectors on this item—do not require GFCI breakers on circuits connected to ac modules until it is a code requirement and specifically listed products are available to properly provide protection.

Marking

Ac module marking is covered specifically in 690.52. These markings are:
(1) Nominal operating ac voltage
(2) Nominal operating ac frequency
(3) Maximum ac power
(4) Maximum ac current
(5) Maximum overcurrent device rating for ac module protection

690.52(5) would normally be the maximum rating of the branch circuit breaker feeding the circuit to the ac modules. The markings of 690.51 (PV module) and 690.53 (PV power source) are not required on the ac module.

The output of ac modules is defined as an inverter output circuit [690.6(B)] and the overcurrent protection for that circuit is permitted to follow the requirements of 240.5(B)(2) for fixture wires. This is significant in that it allows products to have smaller wire connected to OCPDs. By allowing smaller conductors in circuits with larger OCPDs, a product is allowed to have small conductors connected directly to the ac module while feeding power into a larger feeder. The fixture wire provisions even allow as small as 18AWG conductors to be protected by a 20-amp OCPD provided that the circuit is no longer than 20 feet. This is permissive language and does not trump the sizing and OCPD for standard wiring systems. It does allow specialty wiring systems that are evaluated as part of the product listing. Once the circuit reaches the inverter output circuit's OCPD, all aspects of an ac module are identical to other utility-interactive PV systems from that point onward.

Micro-Inverter Systems in the NEC

The term "micro-inverter" is not used in the NEC through the 2011 version. Therefore, the requirements for micro-inverter installations must be ascertained from a series of code requirements that relate to these devices. The key sections of article 690 that provide specific guidance to micro-inverter installations are covered here sequentially.

Maximum system voltage

690.7 defines maximum system voltage as it applies to the dc PV array. Since the PV array is only one or two modules, the worst-case value for most of the U.S. would be to multiply the module rated open-circuit voltage (Voc) by 1.25 since that covers crystalline silicon modules down to 40°F or -40°C. For simplicity, take the maximum allowable dc

voltage for the micro-inverter and divide that value by 1.25. This means that a micro-inverter with a 60-Volt maximum system voltage can use any crystalline-silicon module that has a rated Voc of 48 Volts or less without exceeding maximum voltage. For situations where this simplified 1.25 factor does not work, the standard calculations for maximum system voltage, detailed in section 6 of this guideline, should be used.

Disconnecting Means

Since most micro-inverters are mounted in locations that are not readily accessible (e.g. sloped rooftops), then we must review the requirements of *690.14 (D) Utility-Interactive Inverters Mounted in Not-Readily-Accessible Locations.*

This provision specifically allows micro-inverters to be installed in places that are not readily accessible like rooftops. In order to meet the requirements, the micro-inverter must have dc and ac disconnects in sight of the inverter. These disconnects would also be in a not-readily accessible locations so 690.14(D)(3) requires that an additional ac disconnect be in a readily accessible location. This provision can be met as simply as a circuit breaker at the ac point of connection in the main service panel on a house. Lastly, 690.14(D)(4) requires that a sign be placed at the service entrance notifying where the inverters are located on the premises. The cited article 705.10 allows large numbers of inverters to be identified in groups rather than individually.

690.14(D) begs the question as to whether disconnects now have to be mounted with the micro-inverters. Bulky, vertically mounted disconnects would clearly make micro-inverters impractical. However, the exception at the end of 690.17 clarifies that a connector may be used as a disconnect provided the connector meets the requirements of 690.33 and is identified for the application. All the requirements in 690.33 apply, but the most specific relates to interruption of the circuit, 690.33(E).

690.33(E) Interruption of Circuit. Connectors shall be either (1) or (2): (1) Be rated for interrupting current without hazard to the operator. (2) Be a type that requires the use of a tool to open and marked "Do Not Disconnect Under Load" or "Not for Current Interrupting."

Some micro-inverter manufacturers have their connectors certified as capable of interrupting maximum current without hazard to the operator. Those that do not have this certification must have connectors that require a tool along with the required marking to prevent inadvertent disconnect under load.

System and Equipment Grounding of Micro-Inverters

Since all the dc requirements remain in effect for a micro-inverter, the system grounding rules apply. If a product requires a conductor to be grounded, a grounding electrode (GEC) must be run from the inverter to the grounding electrode system. The minimum size GEC for dc or ac systems is 8AWG [250.166 or 250.66]. Since micro-inverters may choose to ground the dc side of the system, those inverters will need an 8AWG conductor run to the grounding electrode system. 690.47(C)(3) allows for the dc GEC to be combined with the ac equipment grounding conductor (EGC) and for that combined conductor to be terminated at the grounding busbar in the service equipment where the ac circuit originates. This means that a bare or sunlight resistant 8AWG or 6AWG can be run, outside of a raceway and adjacent to the ac conductors, to pick up both the GEC and EGC requirements of a micro-inverter array. At the point where the current carrying conductors transition from the array to the wiring method going to the service panel, the combined GEC/EGC can be irreversibly spliced to a stranded 8AWG to be landed at the grounding busbar in the service equipment.

If the inverter is ungrounded, no GEC is required. Therefore, the EGC must simply be that required by the OCPD supplying the circuit and sized according to Table 250.122. The EGC can now easily be incorporated into the ac connector system provided that it the EGC is the first to make and last to break according to 690.33(D).

Marking

Again, since dc requirements remain for micro-inverters, 690.53, marking for the PV power source applies. In this case, manufacturing a new sign is somewhat problematic since the dc disconnect is a connector. 690.53 requires that the sign be mounted on or adjacent to the PV power source disconnect. Alternatively, the PV module, as required in 690.51, has very similar marking requirements and the marking is adjacent to the PV power source disconnect, the dc connectors. The purpose of the 690.53 sign is to identify the PV array connected to an inverter since the array is often not visible from the location of the inverter, or the size of array is not obvious at the inverter. In the case of the micro-inverter, the array is essentially being held in the hands of the person operating the PV power source disconnect, with the array plainly marked [690.51], so the intent of 690.53 is met.

Span Table R802.5.1(2),

Use this table for rafter spans with a ceiling attached and conventional light-weight dead loads.

10 PSF Dead Load Roof live load = 20 psf, ceiling attached to rafters, L/Δ=240							
		Rafter Size	2 x 4	2 x 6	2 x 8	2 x 10	2 x 12
Spacing (inches)	Species	Grade	The measurements below are in feet-inches (e.g. 9-10 = 9 feet, 10 inches).				
16	Douglas Fir-larch	#2 or better	8-11	14-1	18-2	22-3	25-9
16	Hem-fir	#2 or better	8-4	13-1	17-3	21-11	25-5
24	Douglas Fir-larch	#2 or better	7-10	11-9	14-10	18-2	21-0
24	Hem-fir	#2 or better	7-3	11-5	14-8	17-10	20-9

Use this table for rafter spans with a ceiling attached and where heavy dead loads exist.

20 PSF Dead Load Roof live load = 20 psf, ceiling attached to rafters, L/Δ=240							
		Rafter Size	2 x 4	2 x 6	2 x 8	2 x 10	2 x 12
Spacing (inches)	Species	Grade	The measurements below are in feet-inches (e.g. 9-10 = 9 feet, 10 inches).				
16	Douglas Fir-larch	#2 or better	8-6	12-5	15-9	19-3	22-4
16	Hem-fir	#2 or better	8-4	12-3	15-6	18-11	22-0
24	Douglas Fir-larch	#2 or better	6-11	10-2	12-10	15-8	18-3
24	Hem-fir	#2 or better	6-10	10-0	12-8	15-6	17-11

Use the conventional light-weight dead load table when the existing roofing materials are wood shake, wood shingle, composition shingle, or light-weight tile. (The rationale for allowing these tables to be used is that the installation of a PV system should be considered as part of the live load, since additional loading will not be added to the section of the roof where a PV array is installed.)

Where heavy roofing systems exist (e.g. clay tile or heavy concrete tile roofs), use the 20 lbs/ft^2 dead load tables.

APPENDIX D: SPECIAL ELECTRICAL TOPICS

Module Frame Grounding

Module frame grounding has been a subject of confusion and controversy for many years. The primary concern raised by industry experts, including the Solar ABCs, has been the fact that the anodized aluminum frames in contact with anodized aluminum rails may not create an adequate and reliable electrical connection for bonding and grounding requirements. Until this issue was raised, many inspectors and contractors were satisfied with grounding the metal support structure rather than grounding individual modules. Several standard and new grounding methods can address the electrical bond of the module frame to its support by penetrating each nonconductive surface with a sharp, metallurgically compatible device. This device may be a simple as a stainless steel star washer, or as unique as a specially designed grounding clip with sharp points to pierce the anodizing, addressing the concern of creating a solid electrical connection that will resist corrosion.

PV module grounding options include a variety of methods, such as grounding screws or lugs on each module connected to a ground wire, or methods that create an electrical bond between the module frame and its support structure. Installation manuals for PV modules have become more explicit about grounding methods. The appropriate grounding means are to be defined in the module installation instructions as part of the UL1703 listing. While equipment grounding requirements for PV modules still require some level of interpretation by the local jurisdiction, clarifying language is being proposed for the UL1703 standard that should address most of the current ambiguities.

AC Connection to Building Electrical Systems

AC Connection to Load Side of Main Service Panel

The connection of a PV system's inverter output circuit to the load side of the Main Service panel is the most common installation method. This type of connection is governed by the requirements of NEC 705.12(D) and 690.64(B) in the 2008 NEC. These requirements dictate that the maximum sum of the current ratings of overcurrent protection devices (OCPDs) that can be fed into a conductor or busbar is 120% of the busbar or conductor rating [NEC 705.12(D)(2)]. For example, if a busbar has a current rating of 225-amps, and a main breaker rated at 200-amps, then the maximum breaker rating for a PV inverter is 70-amps as shown below:

Maximum allowable OCPD: Busbar = 225A; 120% of Busbar = 225A x 1.2 = 270A

Existing Main OCPD = 200A

Maximum PV OCPD = Maximum allowable OCPD - Existing Main OCPD = 270A - 200A = 70A

To determine the maximum size inverter that can be fed into a 70A OCPD, remember that most circuit breakers and other OCPDs are limited to 80% of their current rating for continuous operation. This means that 70A circuit breaker must be sized so that 56A can pass through the breaker on a continuous basis (3-hours or more). Since PV inverters are rated based on their maximum power at 40C for a continuous 3-hour period, an inverter capable of a continuous 56A is capable of 11,648 Watts at 208Vac; 13,440Wac at 240Vac; and 15,512Wac at 277Vac.

The only way to put more current into the load side of the service panel in this is example, is to reduce the size of the main OCPD. To the extent that the main OCPD is reduced, the PV inverter OCPD may be increased. However, any time a main OCPD is reduced, a load calculation following the requirements of NEC Article 220 must be calculated to show that the load on the main OCPD will not see more than an 80% continuous load at the chosen OCPD rating.

If no other panel boards exist on this service, the only other opportunity to install a larger PV system is to make a supply-side service connection [NEC 705.12(A) in the 2011 NEC and 690.64(A) in the 2008 NEC]. This method is discussed in the AC Supply Side Connection section in this Appendix.

AC Connection to Subpanel

When a site service contains more than one panel board, the panels fed from the main service panel are referred to as subpanels. The NEC, in 705.12(D) and NEC 690.64(B)(1) in the 2008 NEC, allows the inverter OCPD to be connected at any location in the premises wiring system, provided that the 120% of busbar and conductor ampacity limitation is observed.

For example, a large residence has a main panel with a 400-amp rating with a 400-amp main OCPD. From a 200-amp breaker in this 400-amp panel is a 200-amp panel at the opposite end of the residence. In this example, the PV array is located much closer to the 200-amp panel, so the preferred interconnection point is the 200-amp panel. As long as the inverter OCPD complies with limitations of the 200-amp panel, the inverter can interconnect at that panel.

With a 200-amp busbar and a 200-amp main breaker, the largest PV OCPD allowed in that panel is 40-amps (see discussion on AC Connection to Load Side of Main Service Panel in this Appendix). Assuming a 40-amp PV OCPD is sufficient for the PV inverter (e.g. 7000 Watt inverter), the issues of concern in the subpanel are addressed.

Now consider the current flow at the main service panel. The 2011 NEC instructs the installer to calculate the sum of the supply OCPDs at the main service panel based on the rating of inverter OCPD, which is 40-amps, not the 200-amp feeder breaker that feeds the subpanel [NEC 705.12(D)(2) and NEC 690.64(B)(2) in the 2008 NEC]. Clearly, the 40-amp PV OCPD does not exceed the 120% of busbar rating in the 400-amp panel, whereas, had the 200-amp feeder breaker value been used in the calculation, the installation would have been in violation.

To further extend this example, should another PV inverter be desired, due to the large electrical consumption of the residence, there is still ampacity allowance in the 400-amp main panel busbar. The allowable inverter OCPD size would be calculated as follows:

Maximum allowable OCPD: Busbar = 400A; 120% of Busbar = 400A x 1.2 = 480A

Existing Main OCPD = 400A; Inverter OCPD in 200A subpanel = 40A

Maximum PV OCPD in 400A panel = Maximum allowable OCPD - Existing Main OCPD - Inverter OCPD in 200A subpanel = 480A - 400A - 40A = 40A

Therefore an additional 40A inverter OCPD could be placed in the main panel without any changes to the panel.

Should a larger PV system be desired than could be handled by the two 40A breakers in this example, refer to the discussions in AC Connection to Load Side of Main Service Panel in this Appendix.

AC Supply Side Connection

When the size of PV system is relatively large relative to the size of the site service, it is fairly common to consider a supply side connection for the inverter OCPD. Whenever the 120% allowance for OCPDs connected to busbars or conductors cannot be observed, due to size of the required PV OCPD and the limited size of the service panel, the supply side connection may be the only alternative available. A supply side connection is defined as a connection made between the service meter and the service disconnect.

Not all services can be legally connected at this point. For instance, many all-in-one meter panels, used routinely in new residential construction, have no means of making such a connection without violating the listing of the product. On the other end of the size spectrum, many large 3,000-amp service panels have no space for such a connection. To further complicate this situation, some utilities have begun requiring metering current transformers to be installed on the load side of service OCPD, making a supply side connection impossible.

With those complications aside, we will discuss the situations where a supply side connection is possible and does not violate the equipment listings of the service equipment. The NEC covers supply side connections in 705.12(A) and 690.64(A) in the 2008 NEC. These sections refer back to article 230.82. The supply side connection for the PV system must have a disconnect and OCPD located immediately adjacent to the main service disconnect as specified in 230.91. If the connection is not adjacent, then there must be sign or directory showing where the disconnect(s) are located [NEC 690.56(B)]. Even though the tap rule, discussed in Article 240.99 does not apply to supply side connections, the conductors connecting the supply side connection to the PV OCPD are sized according to the OCPD rating. Therefore, if a 60-amp fused disconnect is used as the PV OCPD, the conductor size between the supply side connection and the PV OCPD need only be 6AWG, regardless of the size of service conductors.

The method of termination of PV conductors to the supply conductors or busbar, depends on the service equipment and conductors. In any case, the service voltage will need to be interrupted to tie in to the service conductors or busbar (very rare exceptions outlined in NFPA 70E are involved at facilities like hospitals where the cut-in process must be done while energized.) Typical termination methods include several options:

1. lugging to an accessible perforated bus within service equipment;
2. using an empty set of double-barrel lugs within service equipment;
3. using piercing lugs on conductors between the meter and service disconnect;
4. any lug identified for making connections to conductors of the size range installed.

Installing lugs on service conductors will often require removal of service conductors and conduit and reinstalling conductors with a junction box to accommodate the connection.

A standard diagram has been added to the list of standard diagrams for permit submittals. The key issue in the permit process is to clearly define the code approved method of making the electrical connection on the supply side of the service disconnect. An example of the diagram, based on Example 1 in Appendix A, is provided on the next page. This diagram is available as a blank interactive PDF at www.solarabcs.org/permitting

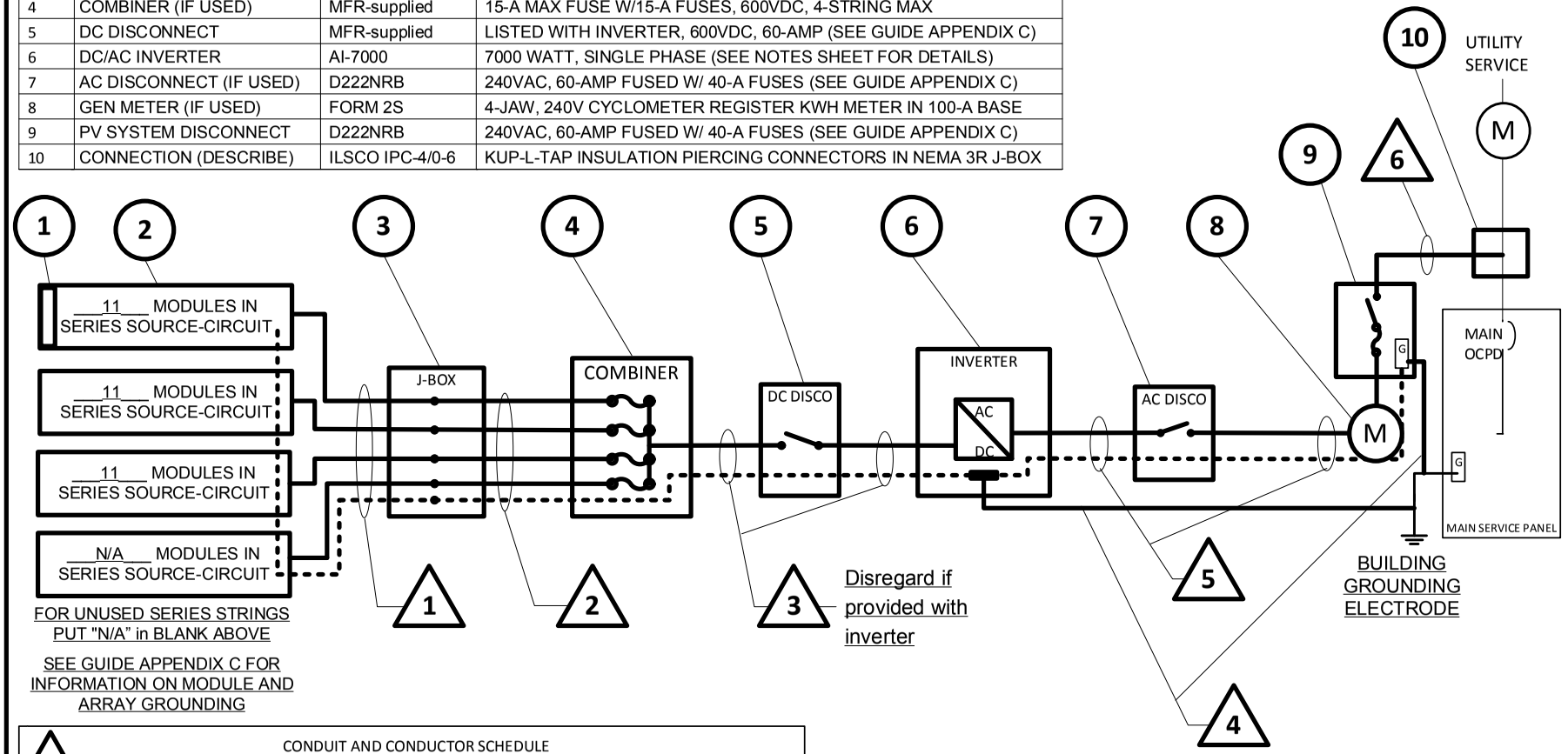
Source Circuit Overcurrent Protection

Source circuit overcurrent protection must be sized so that both the PV module and the conductor from the module to the overcurrent device are properly protected [NEC 690.9 (A), 240.20 (A)]. PV modules must be protected so that the maximum series fuse rating, printed on the listing label, is not exceeded. It is important to note that even though the listing label states "fuse" rating, a more accurate term would be the "maximum series overcurrent protection" rating since either a fuse or a circuit breaker may be used to satisfy this listing requirement. The module may be protected either by installing fuses or circuit breakers in a series string of modules or by the design of the PV system.

Inverters listed with a maximum utility back feed current that is well above 2 amps (typically equal to the maximum allowable output overcurrent protection) must be assumed to provide back feed current to the PV array. Each source circuit must have overcurrent protection that is greater than or equal to the minimum PV Source Circuit current rating and less than or equal to the maximum series fuse rating.

Diagram for Example 1

EQUIPMENT SCHEDULE			
TAG	DESCRIPTION	PART NUMBER	NOTES
1	SOLAR PV MODULE	AS 230	AMERICAN SOLAR, QUANTITY - 33 (SEE NOTES SHEET FOR DETAILS)
2	PV ARRAY	N/A	ARRAY IS 3 STRINGS WITH 11 MODULES PER SERIES STRING
3	J-BOX (IF USED)		6"x6"x4" NEMA 4, PVC JUNCTION BOX
4	COMBINER (IF USED)	MFR-supplied	15-A MAX FUSE W/15-A FUSES, 600VDC, 4-STRING MAX
5	DC DISCONNECT	MFR-supplied	LISTED WITH INVERTER, 600VDC, 60-AMP (SEE GUIDE APPENDIX C)
6	DC/AC INVERTER	AI-7000	7000 WATT, SINGLE PHASE (SEE NOTES SHEET FOR DETAILS)
7	AC DISCONNECT (IF USED)	D222NRB	240VAC, 60-AMP FUSED W/ 40-A FUSES (SEE GUIDE APPENDIX C)
8	GEN METER (IF USED)	FORM 2S	4-JAW, 240V CYCLOMETER REGISTER KWH METER IN 100-A BASE
9	PV SYSTEM DISCONNECT	D222NRB	240VAC, 60-AMP FUSED W/ 40-A FUSES (SEE GUIDE APPENDIX C)
10	CONNECTION (DESCRIBE)	ILSCO IPC-4/0-6	KUP-L-TAP INSULATION PIERCING CONNECTORS IN NEMA 3R J-BOX



FOR UNUSED SERIES STRINGS PUT "N/A" in BLANK ABOVE

SEE GUIDE APPENDIX C FOR INFORMATION ON MODULE AND ARRAY GROUNDING

△ CONDUIT AND CONDUCTOR SCHEDULE					
TAG	DESCRIPTION OR CONDUCTOR TYPE	COND. GAUGE	NUMBER OF CONDUCTORS	CONDUIT TYPE	CONDUIT SIZE
1	USE-2 ☒ or PV WIRE ☐	10 AWG	8 BLACK	N/A	N/A
	BARE COPPER EQ. GRD. COND. (EGC)	10 AWG	1 BARE CU	N/A	N/A
2	THWN-2 ☒ or XHHW-2 ☐ or RHW-2 ☐	10 AWG	4-R, 4-W, 1-G	EMT	¾"
3	THWN-2 ☒ or XHHW-2 ☐ or RHW-2 ☐	N/A	N/A	N/A	N/A
	INSULATED EGC	N/A	N/A		
4	GROUNDING ELECTRODE COND.	6 AWG	1 BARE CU	N/A	N/A
5	THWN-2 ☒ or XHHW-2 ☐ or RHW-2 ☐	8 AWG	1-R, 1-B, 1-W	EMT	¾"
	INSULATED EGC	10 AWG	1 GREEN		
6	THWN-2 ☒ or XHHW-2 ☐ or RHW-2 ☐	6 AWG	1-R, 1-B, 1-W	EMT	¾"

Contractor Name, Address and Phone:

Bill and Ted's Solar
456 Excellent Drive
San Dimas, CA
800-555-1212

Drawn By: Bill

Checked By: Ted

One-Line Electrical Diagram for Supply-Side Connected Single-Phase PV Systems

Site Name: Joe and Jane Homeowner
Site Address: 123 Sunnyside St., Fontana, CA
System AC Size: 6.1 kW Solar Array

SIZE	FSCM NO	DWG NO	REV
		E1.1c	0
SCALE	NTS	Date:	SHEET

Explanation: For source circuit with a maximum circuit current of 6.8 amps and a maximum series fuse rating of 15 amps, The minimum fuse rating would be 9 amps (next larger fuse rating above 8.5 amps; 6.8A x 1.25 = 8.5A) and the maximum would be 15 amps.

For inverters listed with a maximum utility back feed current that is 2 amps or less (e.g. Fronius IG 4000), two source circuits can be connected to the inverter without requiring overcurrent protection on either circuit.

Explanation: If an array containing two strings in parallel is connected to an inverter that is a limited back feeding source (2 amps or less), the maximum current in a string is equal to the current from the other string in parallel plus the maximum back-fed current from the inverter. If the maximum current of each string is 6.8 Amps, and the inverter provides 2 amps, then the maximum current in a fault at any PV module is 8.8 Amps and the maximum series fuse rating of the module will never be exceeded (i.e. a module with an I_{SC} of 5.4 amps will have a maximum series overcurrent device rating of at least 10 amps).

For smaller inverters listed with a maximum utility back feed current that is no larger than the module maximum overcurrent device rating (e.g. Enphase M200 with a 1.6 amp utility backfeed), a single source circuit can be connected to the inverter without requiring overcurrent protection on the array circuit.

Explanation: If a single string array (could be a single module array) is connected to an inverter that provides less than the rated module maximum overcurrent device rating in backfeed current, it is equivalent to having that size overcurrent device prevent current flow from the utility and the array is protected. The maximum reverse fault current at any PV module is the amount of the inverter utility backfeed current and the maximum series fuse rating of the module will never be exceeded.

Disconnecting Means

The NEC defines disconnecting means in the following way:
"NEC Article 100 Disconnecting Means. A device, or group of devices, or other means by which the conductors of a circuit can be disconnected from their source of supply."

A primary purpose of a disconnecting means is to open a circuit providing a source of supply so that the equipment fed by that source can be maintained without exposing the operator to hazardous voltages. NFPA 70E, Standard of Electrical Safety in the Workplace refers to this as an electrically safe work condition.

Disconnecting Means in Inverters

Various inverters have provided a variety of integral dc and ac disconnects. These disconnects may or may not provide the necessary isolation for maintenance. The key in differentiating whether the supplied disconnects provide the appropriate isolation is to review the primary method of maintenance and repair of the device. If the device has a standard means of removing the parts needing service, without exposing the technician to hazardous voltages (anything over 50 Volts), the supplied disconnects meet the intent of maintenance disconnecting means. If the technician is exposed to voltages above 50 Volts during service, even with the supplied disconnecting means, external disconnecting means may be necessary.

It is important to point out that every currently available PV inverter that does not operate on a battery system has input capacitors. These capacitors may remain energized for five or more minutes after all external sources are removed from an inverter. Internal bleed resistors remove this voltage over a prescribed time period, and warning labels are provided on the inverter to identify this hazard. This hazard is typical of electrical equipment using significant capacitance. This capacitive source is controlled by warning signage and bleed resistors and not generally by internal or external disconnects. Disconnects should not be required to control the capacitive source during maintenance or service of the inverter.

Utility-Required Disconnecting Means

Utilities may require some method to isolate PV systems from their grid during maintenance procedures. The isolation device is usually required to provide a visible break in order to comply, and molded-case circuit breakers do not meet that requirement. Several utilities, including the utility with the most PV installations in the U.S., Pacific Gas & Electric, have adopted a policy of allowing residential PV systems with self-contained meters (the most common residential-type meter) to provide the necessary visible break via removal of the meter. For installations with current-transformer meters, a separate visible-break switch is almost always required. When the utility requires a visible-break switch, this switch may be used to provide the NEC-required ac switch for maintaining the inverter if the inverter is located in the immediate vicinity of the switch.

Provisions for the Photovoltaic Power Source Disconnecting Means

The NEC states in 690.14(C)(1), "Location. The photovoltaic disconnecting means shall be installed at a readily accessible location either outside of a building or structure or inside nearest the point of entrance of the system conductors."

a) Readily accessible—NEC Article 100 defines, *"Accessible, Readily (Readily Accessible). Capable of being reached quickly for operation, renewal, or inspections without requiring those to whom ready access is requisite to climb over or remove obstacles or to resort to portable ladders, and so forth."*
b) The "readily accessible" provision is primarily for emergency operation. If the disconnect is not mounted in close proximity of the service entrance disconnect (usually within 10 feet of the meter location or service disconnect switch), then a diagram or directory must be provided to clearly identify where the disconnecting means is located.
c) A rooftop disconnect on a residential roof will normally not qualify as a readily accessible disconnect.

An exception to this requirement was added to the 2005 NEC to provide additional clarification for residential and building integrated PV systems. This exception reads:

> *"Exception: Installations that comply with 690.31(E) shall be permitted to have the disconnecting means located remote from the point of entry of the system conductors."*

NEC 690.31(E) states:

"(E) Direct-Current Photovoltaic Source and Output Circuits Inside a Building. Where direct current photovoltaic source or output circuits of a utility-interactive inverter from a building-integrated or other photovoltaic system are run inside a building or structure, they shall be contained in metal raceways or metal enclosures from the point of penetration of the surface of the building or structure to the first readily accessible disconnecting means. The disconnecting means shall comply with 690.14(A) through 690.14(D)."

Although metal-clad cable is not specifically called out in 690.31(E), in the 2005 and 2008 NEC, many jurisdictions consider installations with metal-clad cable as meeting the intent of this provision.The 2011 NEC specifically allows MC cable in this application by adding the phrase, "Type MC metal-clad cable that complies with 250.118 (10)," to the list of allowed wiring methods. Note that this section specifically mentions building-integrated systems. The way the 2002 NEC was written, a roof-integrated PV system cannot reasonably comply with 690.14(C)(1) as written.

APPENDIX E: COSTS OF PERMITS

Each jurisdiction may have different internal costs structures and approaches to working with solar PV systems. The following section is provided as a suggestion in developing the cost structure for a local jurisdiction.

Explanation: Costs for permits are often based on the overall project cost. This works well for many conventional projects because this accurately represents the scale of the project. However, with a PV installation, the equipment costs are much higher than with other projects of similar scope. It is therefore recommended that an alternative permit fee scale be used for PV system installations. The scope of a PV installation is similar to that of installing a retrofitted residential HVAC system. The permitting costs for a PV system should be similar to those for an HVAC system.

Although initial plan review and field inspection costs may be slightly higher for the first few systems, those costs should reduce as the local jurisdiction becomes familiar with the installations. A subdivision of more than 10 units should be considered for an additional fee reduction based on the repetitive nature of the reviews. A suggested fee schedule is as follows:

Small PV system (up to 4 kW): $75 - $200
Large PV system (up to 10 kW): $150 - $400

For systems of 10-50 kW, consider a permit cost of $15 - $40 per kW.

For systems of 50-100 kW, consider a permit cost of $1,500.

For systems of 100-500 kW, consider a permit cost of $3,000.

For systems up to 1000 kW, consider a permit cost of $3,000-$5,000.

APPENDIX F: TEMPERATURE TABLES

Design Temperatures For Various U.S. Cities

The tables on the following pages indicate low and high ambient design temperatures that must be used when designing code-compliant PV systems. These temperatures have been provided by ASHRAE, and are given in degrees Celsius. The high temperatures are used for conductor sizing and calculations of minimum array operating voltage. The low temperatures are used in the NEC 690.7 calculation.

This website provides an alternative method of viewing this same data:
http://www.solarabcs.org/about/publications/reports/expedited-permit/map/index.html

There are several numbers listed for each site. A description of each number follows:

Elev.: the elevation in meters of the meteorological site.

High Temp (0.4%): this air temperature is only exceeded during 3 hours (not necessarily continuous) of a summer month (June through August). This number is slightly more conservative than the 2% value.

High Temp (2%): this number is likely exceeded during 14 hours (not necessarily continuous) over a summer month (June through August). The Copper Development Association recommends that this number be used for ampacity calculations.

Distance above roof: The high temperature numbers refer only to the air temperature. According to the National Electrical Code, the temperature within rooftop raceways shall be assumed higher than ambient; these temperatures are dependent upon the minimum height of that conduit above the roof (NEC 2008 Table 310.15(B)(2)(c), or NEC 2011 Table 310.15(B)(3)(c)). The three figures here (0.5", 3.5", 12") are based off the High Temp (2%) numbers. Conduit that touches the roof, or is less than 0.5" above the roof is not listed since it is poor practice to mount conduit this close to the roof in general.

Extreme Min: The lowest expected ambient temperature for this site. This number should be used for the calculations for maximum system voltage required in NEC 690.7. An Informational Note in 690.7(A) in the 2011 NEC specifies this value, the Extreme Annual Mean Minimum Design Dry Bulb Temperature from ASHRAE Handbook—Fundamentals, as the proper value for lowest expected ambient temperature.

Temperature Table Continued

State	Station	Elev	High Temp (°C)		Distance above roof			Extreme
		(M)	0.4%	2% Avg	0.5"	3.5"	12"	Min (°C)
AK	ADAK NAS	6	17	14	36	31	28	-11
AK	AMBLER	88	27	24	46	41	38	N/A
AK	ANAKTUVUK PASS	657	24	21	43	38	35	N/A
AK	ANCHORAGE INTL AP	40	24	21	43	38	35	-26
AK	ANCHORAGE MERRILL FIELD	42	25	22	44	39	36	-26
AK	ANCHORAGE/ELMENDORF	59	26	23	45	40	37	-29
AK	ANNETTE ISLAND AP	34	25	22	44	39	36	-13
AK	ANVIK	99	24	22	44	39	36	-34
AK	BARROW W POST-W ROGERS ARPT	4	18	13	35	30	27	-43
AK	BARTER ISLAND (DEW)	12	16	13	35	30	27	N/A
AK	BETHEL AIRPORT	46	25	22	44	39	36	-35
AK	BETTLES FIELD	196	29	25	47	42	39	-48
AK	BIG DELTA ALLEN AAF	388	28	25	47	42	39	-42
AK	CAPE LISBURNE(AWOS)	3	17	14	36	31	28	N/A
AK	CAPE NEWENHAM AFS	161	18	16	38	33	30	N/A
AK	CAPE ROMANZOFF AWOS	123	20	18	40	35	32	N/A
AK	COLD BAY ARPT	31	17	15	37	32	29	-16
AK	CORDOVA	15	24	21	43	38	35	-22
AK	DEADHORSE	18	23	18	40	35	32	-45
AK	DILLINGHAM MUNI	29	24	21	43	38	35	-33
AK	DUTCH HARBOR	4	19	16	38	33	30	-10
AK	FAIRBANKS INTL ARPT	138	30	26	48	43	40	-43
AK	FAIRBANKS/EIELSON A	167	30	26	48	43	40	-44
AK	FIVE FINGER ISLAND	21	20	18	40	35	32	-9
AK	FORT YUKON	138	29	26	48	43	40	-49
AK	FT. RICHARDSON/BRYA	115	26	23	45	40	37	-31
AK	GALENA A.	49	28	25	47	42	39	-46
AK	GULKANA INTERMEDIATE FIELD	481	27	25	47	42	39	-41
AK	HOMER ARPT	22	21	18	40	35	32	-20
AK	HOOPER BAY	6	19	17	39	34	31	N/A
AK	ILIAMNA ARPT	49	26	21	43	38	35	-29
AK	INDIAN MTN AFS AWOS	372	27	24	46	41	38	N/A
AK	JUNEAU INT'L ARPT	7	26	23	45	40	37	-18
AK	KAKE SEAPLANE BASE	0	22	20	42	37	34	-14
AK	KENAI MUNICIPAL AP	28	24	20	42	37	34	-33
AK	KETCHIKAN INTL AP	29	24	21	43	38	35	-14
AK	KING SALMON ARPT	15	25	22	44	39	36	-34
AK	KLAWOCK	15	22	21	43	38	35	-12
AK	KODIAK AIRPORT	34	24	20	42	37	34	-17
AK	KOTZEBUE RALPH WEIN MEMORIAL	5	23	19	41	36	33	-39
AK	LAKE HOOD SEAPLANE	40	26	23	45	40	37	-24
AK	MCGRATH ARPT	103	28	25	47	42	39	-46
AK	MCKINLEY PARK	524	26	23	45	40	37	N/A
AK	MEKORYUK	15	18	15	37	32	29	-29
AK	MIDDLETON ISL. AMOS	37	20	17	39	34	31	-9
AK	MINCHUMINA	213	26	24	46	41	38	N/A
AK	NENANA MUNICIPAL AP	110	30	26	48	43	40	-46
AK	NOME MUNICIPAL ARPT	7	24	20	42	37	34	-36
AK	NORTHWAY AIRPORT	525	28	25	47	42	39	-47
AK	PALMER MUNICIPAL	76	26	23	45	40	37	-28
AK	PETERSBURG	33	23	21	43	38	35	-16
AK	POINT HOPE (AWOS)	4	18	14	36	31	28	N/A
AK	PORT HEIDEN	29	21	17	39	34	31	-24
AK	SAINT MARY`S (AWOS)	95	24	21	43	38	35	-34
AK	SAND POINT	7	18	15	37	32	29	-12
AK	SEWARD	18	26	20	42	37	34	-17
AK	SHEMYA AFB	31	13	11	33	28	25	-8
AK	SHISHMAREF (AWOS)	2	19	15	37	32	29	N/A
AK	SITKA JAPONSKI AP	20	20	18	40	35	32	-11
AK	SKAGWAY AIRPORT	13	24	22	44	39	36	-18
AK	SOLDOTNA	34	25	22	44	39	36	-33
AK	SPARREVOHN AFS	484	24	22	44	39	36	-35
AK	ST PAUL ISLAND ARPT	9	14	12	34	29	26	-18
AK	TALKEETNA STATE ARPT	109	28	24	46	41	38	-35
AK	TATALINA LRRS	301	27	24	46	41	38	N/A
AK	TIN CITY AFS (AWOS)	83	20	15	37	32	29	N/A
AK	TOGIAC VILLAGE AWOS	6	22	19	41	36	33	-31
AK	UNALAKLEET FIELD	6	25	20	42	37	34	N/A
AK	VALDEZ PIONEER FIEL	38	23	21	43	38	35	-21
AK	VALDEZ WSO	11	25	21	43	38	35	-17

Temperature Table Continued

State	Station	Elev	High Temp (°C)		Distance above roof			Extreme
		(M)	0.4%	2% Avg	0.5"	3.5"	12"	Min (°C)
AK	WHITTIER	9	24	21	43	38	35	-16
AK	WRANGELL	13	23	21	43	38	35	-13
AK	YAKUTAT STATE ARPT	9	22	19	41	36	33	-20
AL	ANNISTON METROPOLITAN AP	183	37	34	56	51	48	-11
AL	AUBURN-OPELIKA APT	236	36	33	55	50	47	-9
AL	BIRMINGHAM MUNICIPAL AP	192	37	34	56	51	48	-12
AL	CAIRNS AAF/OZARK	91	37	35	57	52	49	-8
AL	CENTREVILLE WSMO	138	36	34	56	51	48	-11
AL	DAUPHIN ISLAND	9	32	31	53	48	45	-2
AL	DOTHAN MUNICIPAL	98	37	35	57	52	49	-8
AL	GADSEN MUNI (AWOS)	173	36	34	56	51	48	-12
AL	HUNTSVILLE INTL/JONES FIELD	196	36	34	56	51	48	-13
AL	MAXWELL AFB/MONTGOM	53	38	36	58	53	50	-6
AL	MOBILE REGIONAL AP	67	36	34	56	51	48	-7
AL	MONTGOMERY DANNELLY FIELD	62	37	35	57	52	49	-9
AL	MUSCLE SHOALS REGIONAL AP	171	37	35	57	52	49	-12
AL	TUSCALOOSA MUNICIPAL AP	57	37	35	57	52	49	-11
AR	BATESVILLE (AWOS)	141	38	35	57	52	49	-13
AR	BENTONVILLE (AWOS)	395	36	34	56	51	48	-16
AR	EAKER AFB	80	39	36	58	53	50	-15
AR	EL DORADO GOODWIN FIELD	87	38	36	58	53	50	-9
AR	FAYETTEVILLE DRAKE FIELD	384	37	34	56	51	48	-17
AR	FLIPPIN (AWOS)	350	38	35	57	52	49	-15
AR	FORT SMITH REGIONAL AP	141	39	36	58	53	50	-13
AR	HARRISON FAA AP	422	36	34	56	51	48	-15
AR	JONESBORO MUNI	82	37	35	57	52	49	-15
AR	LITTLE ROCK ADAMS FIELD	78	39	36	58	53	50	-11
AR	LITTLE ROCK AFB	103	40	37	59	54	51	-13
AR	LITTLE ROCK/ADAMS F	351	37	34	56	51	48	-12
AR	PINE BLUFF FAA AP	65	38	36	58	53	50	-9
AR	ROGERS (AWOS)	415	36	33	55	50	47	-15
AR	SILOAM SPRING(AWOS)	364	37	34	56	51	48	-15
AR	STUTTGART (AWOS)	68	37	35	57	52	49	-9
AR	TEXARKANA WEBB FIELD	122	39	36	58	53	50	-9
AR	WALNUT RIDGE (AWOS)	83	37	34	56	51	48	-13
AZ	CASA GRANDA (AWOS)	446	44	42	64	59	56	-4
AZ	DAVIS-MONTHAN AFB	809	42	40	62	57	54	-3
AZ	DOUGLAS BISBEE-DOUGLAS INTL A	1250	39	37	59	54	51	-9
AZ	FLAGSTAFF AIRPORT	2135	32	29	51	46	43	-21
AZ	GRAND CANYON NATL P	2065	34	32	54	49	46	-22
AZ	KINGMAN (AMOS)	1050	41	38	60	55	52	-8
AZ	LUKE AFB/PHOENIX	331	46	43	65	60	57	-1
AZ	NOGALES INTL	1236	39	37	59	54	51	-6
AZ	PAGE MUNI (AMOS)	1304	40	37	59	54	51	-9
AZ	PHOENIX SKY HARBOR INTL AP	337	45	43	65	60	57	1
AZ	PRESCOTT LOVE FIELD	1540	37	34	56	51	48	-12
AZ	SAFFORD (AMOS)	950	42	39	61	56	53	-7
AZ	TUCSON INTERNATIONAL AP	779	43	41	63	58	55	-3
AZ	WINSLOW MUNICIPAL AP	1488	39	36	58	53	50	-15
AZ	YUMA INTL AIRPORT	63	46	43	65	60	57	2
AZ	YUMA MCAS	65	46	43	65	60	57	2
CA	ALAMEDA NAS	4	30	26	48	43	40	3
CA	ARCATA AIRPORT	64	21	19	41	36	33	-3
CA	BAKERSFIELD MEADOWS FIELD	150	42	39	61	56	53	-2
CA	BEALE AFB/MARYSVILE	38	41	38	60	55	52	-3
CA	BISHOP AIRPORT	1263	40	38	60	55	52	-13
CA	BLUE CANYON AP	1610	31	28	50	45	42	-8
CA	BLYTHE RIVERSIDE CO ARPT	120	47	44	66	61	58	-1
CA	BURBANK-GLENDALE-PASSADENA AP	223	38	35	57	52	49	1
CA	CAMARILLO (AWOS)	23	28	27	49	44	41	1
CA	CAMP PENDLETON MCAS	24	32	29	51	46	43	-2
CA	CARLSBAD/PALOMAR	100	28	25	47	42	39	4
CA	CASTLE AFB/MERCED	60	40	37	59	54	51	-3
CA	CRESCENT CITY FAA AI	17	19	18	40	35	32	-1
CA	DAGGETT BARSTOW-DAGGETT AP	588	45	42	64	59	56	-5
CA	EDWARDS AFB	706	43	40	62	57	54	-10
CA	EL TORO MCAS	117	34	31	53	48	45	3
CA	EUREKA	18	19	18	40	35	32	-1
CA	FRESNO YOSEMITE INTL AP	100	42	39	61	56	53	-2
CA	FULLERTON MUNICIPAL	29	34	31	53	48	45	2

Temperature Table Continued

State	Station	Elev	High Temp (°C)		Distance above roof			Extreme
		(M)	0.4%	2% Avg	0.5"	3.5"	12"	Min (°C)
CA	GEORGE AFB	876	42	38	60	55	52	-6
CA	HAYWARD AIR TERM	14	33	28	50	45	42	1
CA	IMPERIAL	-17	46	44	66	61	58	-1
CA	JACK NORTHROP FLD H	21	31	26	48	43	40	4
CA	LANCASTER GEN WM FOX FIELD	713	42	38	60	55	52	-9
CA	LEMOORE REEVES NAS	71	41	39	61	56	53	-3
CA	LIVERMORE MUNICIPAL	121	41	36	58	53	50	-3
CA	LOMPOC (AWOS)	27	26	23	45	40	37	-2
CA	LONG BEACH DAUGHERTY FLD	12	33	30	52	47	44	2
CA	LOS ANGELES INTL ARPT	99	28	26	48	43	40	4
CA	MARCH AFB/RIVERSIDE	462	40	37	59	54	51	-2
CA	MCCLELLAN AFB	25	41	38	60	55	52	-3
CA	MODESTO CITY-COUNTY AP	30	42	38	60	55	52	-2
CA	MONTAGUE SISKIYOU COUNTY AP	805	38	34	56	51	48	N/A
CA	MONTEREY PENINSULA	50	24	22	44	39	36	1
CA	MOUNT SHASTA	1078	35	31	53	48	45	-12
CA	MOUNTAIN VIEW MOFFETT FLD NAS	10	33	29	51	46	43	0
CA	NAPA CO. AIRPORT	17	35	31	53	48	45	-4
CA	NORTON AFB/SAN BERN	353	41	38	60	55	52	-2
CA	OAKLAND METROPOLITAN ARPT	27	29	25	47	42	39	1
CA	ONTARIO	304	39	37	59	54	51	-1
CA	PALM SPRINGS INTL	145	47	44	66	61	58	3
CA	PALM SPRINGS THERMAL AP	-36	47	44	66	61	58	-5
CA	PASO ROBLES MUNICIPAL ARPT	249	42	38	60	55	52	-6
CA	POINT ARENA	19	17	15	37	32	29	2
CA	POINT ARGUELLO	34	21	18	40	35	32	5
CA	POINT MUGU NF	4	26	24	46	41	38	2
CA	PORTERVILLE (AWOS)	135	41	38	60	55	52	-2
CA	PT.PIEDRAS BLANCA	21	21	20	42	37	34	3
CA	RED BLUFF MUNICIPAL ARPT	108	44	40	62	57	54	-4
CA	REDDING MUNICIPAL ARPT	153	44	40	62	57	54	-4
CA	RIVERSIDE MUNI	256	39	36	58	53	50	-1
CA	SACRAMENTO EXECUTIVE ARPT	8	41	37	59	54	51	-3
CA	SACRAMENTO MATHER AIRPORT	29	42	38	60	55	52	-3
CA	SACRAMENTO METROPOLITAN AP	10	41	37	59	54	51	-3
CA	SALINAS MUNICIPAL AP	24	29	25	47	42	39	-1
CA	SAN DIEGO LINDBERGH FIELD	9	29	26	48	43	40	5
CA	SAN DIEGO MIRAMAR NAS	146	32	30	52	47	44	1
CA	SAN DIEGO NORTH ISLAND NAS	8	28	25	47	42	39	4
CA	SAN DIEGO/BROWN FLD	159	31	28	50	45	42	2
CA	SAN DIEGO/MONTGOMER	129	32	28	50	45	42	3
CA	SAN FRANCISCO INTL AP	6	29	25	47	42	39	2
CA	SAN JOSE INTL AP	15	36	32	54	49	46	0
CA	SAN LUIS CO RGNL	66	32	28	50	45	42	-2
CA	SANDBERG	1379	35	32	54	49	46	-5
CA	SANTA BARBARA MUNICIPAL AP	6	29	26	48	43	40	-1
CA	SANTA MARIA PUBLIC ARPT	73	29	25	47	42	39	-3
CA	SANTA ROSA (AWOS)	45	38	34	56	51	48	-3
CA	STOCKTON METROPOLITAN ARPT	8	41	38	60	55	52	-3
CA	TRAVIS AFB/FAIRFLD	18	40	36	58	53	50	-3
CA	TRUCKEE-TAHOE	1798	34	30	52	47	44	N/A
CA	TUSTIN MCAF	17	34	31	53	48	45	2
CA	UKIAH MUNICIPAL AP	191	41	37	59	54	51	-3
CA	VISALIA MUNI (AWOS)	89	39	37	59	54	51	-3
CO	AKRON WASHINGTON CO AP	1409	38	34	56	51	48	-23
CO	ALAMOSA SAN LUIS VALLEY RGNL	2299	32	29	51	46	43	-30
CO	ASPEN PITKIN CO SAR	2444	32	28	50	45	42	-24
CO	BUCKLEY ANGB/DENVER	1726	36	33	55	50	47	-22
CO	COLORADO SPRINGS MUNI AP	1881	35	32	54	49	46	-23
CO	CORTEZ/MONTEZUMA CO	1803	37	34	56	51	48	-19
CO	CRAIG-MOFFAT	1915	35	31	53	48	45	-31
CO	DENVER INTL AP	1655	37	34	56	51	48	-23
CO	DENVER STAPLETON INT'L ARPT	1611	36	34	56	51	48	-25
CO	DENVER/CENTENNIAL	1793	36	33	55	50	47	-23
CO	DURANGO/LA PLATA CO	2038	34	32	54	49	46	-21
CO	EAGLE COUNTY AP	1992	33	30	52	47	44	-28
CO	FORT COLLINS (AWOS)	1529	38	34	56	51	48	-23
CO	FORT COLLINS(SAWRS)	1525	34	32	54	49	46	-23
CO	GRAND JUNCTION WALKER FIELD	1475	39	36	58	53	50	-17
CO	GREELEY/WELD (AWOS)	1420	38	35	57	52	49	-27

Temperature Table Continued

State	Station	Elev	High Temp (°C)		Distance above roof			Extreme
		(M)	0.4%	2% Avg	0.5"	3.5"	12"	Min (°C)
CO	GUNNISON CO. (AWOS)	2339	31	28	50	45	42	-31
CO	HAYDEN/YAMPA (AWOS)	2012	33	30	52	47	44	-25
CO	LA JUNTA MUNICIPAL AP	1285	40	37	59	54	51	-21
CO	LAMAR MUNICIPAL	1129	40	37	59	54	51	-22
CO	LIMON	1635	36	33	55	50	47	-25
CO	MONTROSE CO. ARPT	1755	37	34	56	51	48	-19
CO	PUEBLO MEMORIAL AP	1439	39	36	58	53	50	-24
CO	RIFLE/GARFIELD RGNL	1691	38	34	56	51	48	-22
CO	TRINIDAD LAS ANIMAS COUNTY AP	1751	36	33	55	50	47	-23
CT	BRIDGEPORT SIKORSKY MEMORIAL	5	33	30	52	47	44	-14
CT	HARTFORD BRADLEY INTL AP	55	35	32	54	49	46	-20
CT	HARTFORD BRAINARD FD	6	36	32	54	49	46	N/A
CT	OXFORD (AWOS)	222	33	30	52	47	44	-19
CT	WILLIMANTIC (ASOS)	76	34	32	54	49	46	-19
DE	DOVER AFB	7	36	33	55	50	47	-13
DE	GEORGETOWN/SUSSEX	16	36	33	55	50	47	-11
DE	WILMINGTON NEW CASTLE CNTY AP	24	36	33	55	50	47	-15
FL	APALACHICOLA MUNI AP	6	35	33	55	50	47	-5
FL	CAPE SAN BLAS	2	31	30	52	47	44	-2
FL	CECIL FIELD	27	37	35	57	52	49	-6
FL	CRESTVIEW BOB SIKES AP	56	37	35	57	52	49	-9
FL	CROSS CITY AIRPORT	13	36	34	56	51	48	-6
FL	DAYTONA BEACH INTL AP	13	35	33	55	50	47	-2
FL	DESTIN FT. WALTON	7	34	32	54	49	46	N/A
FL	EGLIN AFB/VALPARAIS	20	36	33	55	50	47	-6
FL	FORT LAUDERDALE HOLLYWOOD INT	3	34	33	55	50	47	5
FL	FORT MYERS PAGE FIELD	6	35	34	56	51	48	2
FL	GAINESVILLE REGIONAL AP	50	35	34	56	51	48	-5
FL	HOMESTEAD AFB	5	34	33	55	50	47	5
FL	HURLBURT FIELD (AF)	12	35	33	55	50	47	-5
FL	JACKSONVILLE INTL ARPT	10	36	34	56	51	48	-5
FL	JACKSONVILLE NAS	7	37	35	57	52	49	-4
FL	JACKSONVILLE/CRAIG	13	36	34	56	51	48	-4
FL	KEY WEST INTL ARPT	6	33	32	54	49	46	10
FL	KEY WEST NAS	7	33	32	54	49	46	10
FL	MACDILL AFB/TAMPA	8	35	34	56	51	48	1
FL	MARATHON AIRPORT	2	34	33	55	50	47	N/A
FL	MAYPORT NS	4	37	34	56	51	48	-3
FL	MELBOURNE REGIONAL AP	8	35	33	55	50	47	0
FL	MIAMI INTL AP	9	34	33	55	50	47	5
FL	MIAMI/KENDALL-TAMIA	3	34	33	55	50	47	4
FL	MOLASSES REEF	11	31	30	52	47	44	9
FL	NAPLES MUNICIPAL	7	34	32	54	49	46	3
FL	NASA SHUTTLE FCLTY	3	34	33	55	50	47	0
FL	OCALA MUNI (AWOS)	27	35	34	56	51	48	-6
FL	ORLANDO EXECUTIVE AP	34	35	34	56	51	48	1
FL	ORLANDO INTL ARPT	32	35	34	56	51	48	-1
FL	ORLANDO SANFORD AIRPORT	17	36	34	56	51	48	1
FL	PANAMA CITY BAY CO	6	36	33	55	50	47	-4
FL	PENSACOLA FOREST SHERMAN NAS	9	36	34	56	51	48	-6
FL	PENSACOLA REGIONAL AP	36	36	34	56	51	48	-6
FL	SARASOTA BRADENTON	10	35	33	55	50	47	0
FL	SOMBRERO KEY	37	32	31	53	48	45	11
FL	SOUTHWEST FLORIDA I	9	35	34	56	51	48	1
FL	ST AUGSUTINE ARPT	3	35	33	55	50	47	N/A
FL	ST PETERSBURG CLEAR	3	35	34	56	51	48	1
FL	ST. AUGUSTINE	9	34	31	53	48	45	0
FL	TALLAHASSEE REGIONAL AP	21	37	35	57	52	49	-8
FL	TAMPA INTERNATIONAL AP	3	34	33	55	50	47	-1
FL	TYNDALL AFB	7	35	32	54	49	46	-5
FL	VENICE PIER	5	32	30	52	47	44	1
FL	VERO BEACH MUNICIPAL ARPT	9	35	33	55	50	47	0
FL	WEST PALM BEACH INTL ARPT	6	34	33	55	50	47	3
FL	WHITING FIELD NAAS	61	36	34	56	51	48	-7
GA	ALBANY DOUGHERTY COUNTY AP	59	37	36	58	53	50	-8
GA	ATHENS BEN EPPS AP	244	37	35	57	52	49	-11
GA	ATLANTA (NEXRAD)	296	36	33	55	50	47	-11
GA	ATLANTA HARTSFIELD INTL AP	313	37	34	56	51	48	-11
GA	AUGUSTA BUSH FIELD	45	38	36	58	53	50	-10
GA	AUGUSTA\DANIEL FLD	128	37	35	57	52	49	-6

Temperature Table Continued

State	Station	Elev	High Temp (°C)		Distance above roof			Extreme
		(M)	0.4%	2% Avg	0.5"	3.5"	12"	Min (°C)
GA	BRUNSWICK MALCOLM MCKINNON AP	7	36	33	55	50	47	-5
GA	COLUMBUS METROPOLITAN ARPT	120	37	35	57	52	49	-9
GA	DEKALB PEACHTREE	313	36	34	56	51	48	-9
GA	DOBBINS AFB/MARIETT	330	36	34	56	51	48	-12
GA	FORT BENNING	88	38	36	58	53	50	-10
GA	FULTON CO ARPT BROW	263	36	34	56	51	48	-11
GA	GAINESVILLE\LEE GIL	389	35	33	55	50	47	-8
GA	HUNTER AAF	13	38	35	57	52	49	-5
GA	MACON MIDDLE GA REGIONAL AP	110	38	35	57	52	49	-9
GA	MOODY AFB/VALDOSTA	71	37	35	57	52	49	-7
GA	ROME R B RUSSELL AP	196	38	35	57	52	49	-11
GA	SAVANNAH INTL AP	16	37	35	57	52	49	-7
GA	VALDOSTA WB AIRPORT	60	37	35	57	52	49	-7
GA	WARNER ROBINS AFB	92	38	36	58	53	50	-8
GA	WAYCROSS WARE CO AP	43	38	35	57	52	49	-6
HI	BARBERS POINT NAS	10	34	32	54	49	46	13
HI	HILO INTERNATIONAL AP	11	30	29	51	46	43	15
HI	HONOLULU INTL ARPT	5	32	32	54	49	46	14
HI	KAHULUI AIRPORT	15	32	31	53	48	45	13
HI	KANEOHE BAY MCAS	6	30	29	51	46	43	16
HI	KONA INTL AT KEAHOL	15	31	30	52	47	44	14
HI	LIHUE AIRPORT	45	30	29	51	46	43	14
HI	MOLOKAI (AMOS)	137	31	30	52	47	44	13
IA	AMES MUNI ARPT	291	34	32	54	49	46	-26
IA	ANKENY REGIONAL ARP	275	37	34	56	51	48	-22
IA	ATLANTIC	360	36	33	55	50	47	N/A
IA	BOONE MUNI	354	35	33	55	50	47	N/A
IA	BURLINGTON MUNICIPAL AP	214	37	33	55	50	47	-23
IA	CARROLL	375	35	33	55	50	47	N/A
IA	CEDAR RAPIDS MUNICIPAL AP	266	36	33	55	50	47	-26
IA	CHARITON	320	37	33	55	50	47	-23
IA	CHARLES CITY	343	33	32	54	49	46	N/A
IA	CLARION	354	35	32	54	49	46	N/A
IA	CLINTON MUNI (AWOS)	216	35	32	54	49	46	-25
IA	CRESTON	394	36	33	55	50	47	-23
IA	DAVENPORT NEXRAD	259	34	32	54	49	46	-25
IA	DES MOINES INTL AP	294	37	33	55	50	47	-25
IA	DUBUQUE REGIONAL AP	329	34	31	53	48	45	-26
IA	ESTHERVILLE MUNI	401	34	31	53	48	45	-26
IA	FAIR FIELD	244	37	34	56	51	48	N/A
IA	FORT DODGE (AWOS)	355	35	32	54	49	46	-27
IA	KEOKUK MUNI	205	38	34	56	51	48	N/A
IA	MARSHALL TOWN MUNI	296	34	32	54	49	46	-26
IA	MASON CITY MUNICIPAL ARPT	373	35	32	54	49	46	-28
IA	OTTUMWA INDUSTRIAL AP	258	37	33	55	50	47	-24
IA	SIOUX CITY SIOUX GATEWAY AP	336	37	33	55	50	47	-26
IA	SPENCER	408	36	32	54	49	46	-28
IA	STORM LAKE	454	36	33	55	50	47	N/A
IA	WASHINGTON	230	36	33	55	50	47	N/A
IA	WATERLOO MUNICIPAL AP	268	36	33	55	50	47	-28
IA	WEBSTER CITY	342	35	33	55	50	47	-25
ID	BOISE AIR TERMINAL	874	39	36	58	53	50	-17
ID	BURLEY MUNICIPAL ARPT	1267	37	33	55	50	47	-20
ID	CALDWELL (AWOS)	740	39	35	57	52	49	-13
ID	CHALLIS	1546	36	32	54	49	46	-29
ID	COEUR D`ALENE(AWOS)	707	36	32	54	49	46	-18
ID	ELK CITY (RAMOS)	1249	38	34	56	51	48	-15
ID	IDAHO FALLS FANNING FIELD	1446	36	33	55	50	47	-26
ID	JOSLIN FLD MAGIC VA	1297	38	34	56	51	48	-16
ID	LEWISTON NEZ PERCE CNTY AP	438	40	35	57	52	49	-14
ID	MCCALL ARPT	1530	33	29	51	46	43	-26
ID	MOUNTAIN HOME AFB	912	40	37	59	54	51	-19
ID	MULLAN (AWRS)	1011	32	30	52	47	44	-21
ID	POCATELLO REGIONAL AP	1365	37	34	56	51	48	-24
ID	SALMON/LEMHI (AWOS)	1233	36	31	53	48	45	-24
IL	AURORA MUNICIPAL	215	35	32	54	49	46	-25
IL	CAHOKIA/ST. LOUIS	126	37	34	56	51	48	-17
IL	CHICAGO MIDWAY AP	188	36	33	55	50	47	-22
IL	CHICAGO OHARE INTL AP	205	36	33	55	50	47	-24
IL	DECATUR	213	36	33	55	50	47	-22

Temperature Table Continued

State	Station	Elev	High Temp (°C)		Distance above roof			Extreme
		(M)	0.4%	2% Avg	0.5"	3.5"	12"	Min (°C)
IL	GLENVIEW NAS	199	36	33	55	50	47	-24
IL	LAWRENCEVILLE\VIN.	131	36	33	55	50	47	-18
IL	MARSEILLES ISLAND	225	36	33	55	50	47	-25
IL	MATTOON/CHARLESTON	220	35	32	54	49	46	-20
IL	MOLINE QUAD CITY INTL AP	181	37	34	56	51	48	-25
IL	MOUNT VERNON (AWOS)	146	36	34	56	51	48	-21
IL	PEORIA GREATER PEORIA AP	202	36	33	55	50	47	-23
IL	QUINCY MUNI BALDWIN FLD	234	37	33	55	50	47	-23
IL	ROCKFORD GREATER ROCKFORD AP	227	35	33	55	50	47	-26
IL	SCOTT AFB/BELLEVILL	135	37	35	57	52	49	-19
IL	SOUTHERN ILLINOIS	128	36	34	56	51	48	-17
IL	SPRINGFIELD CAPITAL AP	187	36	33	55	50	47	-23
IL	STERLING ROCKFALLS	197	35	32	54	49	46	-25
IL	UNIV OF ILLINOIS WI	236	36	33	55	50	47	-23
IL	W. CHICAGO/DU PAGE	231	35	32	54	49	46	-24
IN	EVANSVILLE REGIONAL AP	118	36	34	56	51	48	-19
IN	FORT WAYNE INTL AP	252	35	32	54	49	46	-23
IN	GRISSOM ARB	253	36	33	55	50	47	-23
IN	HUNTINGBURG	161	35	33	55	50	47	N/A
IN	INDIANAPOLIS INTL AP	246	35	32	54	49	46	-22
IN	LAFAYETTE PURDUE UNIV AP	194	36	33	55	50	47	-23
IN	MONROE CO	264	34	32	54	49	46	-21
IN	SOUTH BEND MICHIANA RGNL AP	236	36	32	54	49	46	-22
IN	TERRE HAUTE/HULMAN	175	36	33	55	50	47	-23
KS	CHANUTE MARTIN JOHNSON AP	308	38	35	57	52	49	-19
KS	COFFEYVILLE MUNI	230	38	36	58	53	50	-17
KS	CONCORDIA BLOSSER MUNI AP	452	40	37	59	54	51	-21
KS	DODGE CITY REGIONAL AP	790	40	37	59	54	51	-20
KS	ELKHART (AWOS)	1099	39	37	59	54	51	N/A
KS	FT RILEY/MARSHALL A	324	40	37	59	54	51	-20
KS	GARDEN CITY MUNICIPAL AP	878	39	37	59	54	51	-22
KS	GOODLAND RENNER FIELD	1124	39	36	58	53	50	-23
KS	GREAT BEND (AWOS)	575	41	37	59	54	51	-19
KS	HAYS MUNI (AWOS)	609	41	38	60	55	52	-20
KS	HILL CITY MUNICIPAL AP	677	42	38	60	55	52	-21
KS	LAWRENCE MUNI ARPT	254	39	36	58	53	50	-21
KS	LIBERAL MUNI	901	39	37	59	54	51	-18
KS	MANHATTAN RGNL	330	40	37	59	54	51	-22
KS	MCCONNELL AFB	414	40	37	59	54	51	-17
KS	MEDICINE LODGE ASOS	469	41	38	60	55	52	-17
KS	NEWTON (AWOS)	467	40	36	58	53	50	-17
KS	OLATHE/JOHNSON CO.	334	37	35	57	52	49	-20
KS	PARSONS\TRI CITY	274	38	36	58	53	50	-19
KS	RUSSELL MUNICIPAL AP	568	41	37	59	54	51	-21
KS	SALINA MUNICIPAL AP	391	41	38	60	55	52	-20
KS	TOPEKA FORBES FIELD	329	38	35	57	52	49	-20
KS	TOPEKA MUNICIPAL AP	270	38	35	57	52	49	-21
KS	WICHITA MID-CONTINENT AP	408	41	37	59	54	51	-18
KS	WICHITA/COL. JABARA	433	41	36	58	53	50	-17
KS	WINFIELD\ARK CITY	353	40	37	59	54	51	-17
KY	BOWLING GREEN WARREN CO AP	164	36	33	55	50	47	-17
KY	CAPITAL CITY ARPT	245	35	32	54	49	46	-17
KY	CINCINNATI NORTHERN KY AP	269	36	32	54	49	46	-21
KY	FORT CAMPBELL (AAF)	173	37	34	56	51	48	-16
KY	FORT KNOX/GODMAN	239	37	33	55	50	47	-18
KY	HENDERSON CITY	117	35	33	55	50	47	-19
KY	JACKSON JULIAN CARROLL AP	414	34	31	53	48	45	-18
KY	LEXINGTON BLUEGRASS AP	301	35	33	55	50	47	-19
KY	LONDON-CORBIN AP	369	34	32	54	49	46	-18
KY	LOUISVILLE BOWMAN FIELD	170	37	34	56	51	48	-18
KY	LOUISVILLE STANDIFORD FIELD	149	36	34	56	51	48	-17
KY	PADUCAH BARKLEY REGIONAL AP	126	36	34	56	51	48	-17
KY	SOMERSET(AWOS)	283	37	34	56	51	48	-13
LA	ALEXANDRIA ESLER REGIONAL AP	36	38	35	57	52	49	-7
LA	ALEXANDRIA INTERNATIONAL	27	37	35	57	52	49	-7
LA	BARKSDALE AFB	54	38	35	57	52	49	-9
LA	BATON ROUGE RYAN ARPT	23	35	34	56	51	48	-6
LA	FORT POLK (ARMY)	102	37	35	57	52	49	-6
LA	GRAND ISLE	10	32	31	53	48	45	0
LA	LAFAYETTE REGIONAL AP	13	35	34	56	51	48	-6

Temperature Table Continued

State	Station	Elev	High Temp (°C)		Distance above roof			Extreme
		(M)	0.4%	2% Avg	0.5"	3.5"	12"	Min (°C)
LA	LAKE CHARLES REGIONAL ARPT	3	35	34	56	51	48	-5
LA	MONROE REGIONAL AP	25	37	36	58	53	50	-8
LA	NEW ORLEANS ALVIN CALLENDER F	0	35	33	55	50	47	-5
LA	NEW ORLEANS INTL ARPT	6	36	34	56	51	48	-4
LA	NEW ORLEANS LAKEFRONT AP	3	35	34	56	51	48	-1
LA	PATTERSON MEMORIAL	3	36	33	55	50	47	-3
LA	SALT POINT (RAMOS)	3	34	33	55	50	47	N/A
LA	SHREVEPORT DOWNTOWN	55	39	37	59	54	51	-6
LA	SHREVEPORT REGIONAL ARPT	79	38	36	58	53	50	-8
LA	SOUTHWEST PASS	12	32	31	53	48	45	2
MA	BARNSTABLE MUNI BOA	17	32	28	50	45	42	-16
MA	BOSTON LOGAN INT'L ARPT	9	35	32	54	49	46	-17
MA	BUZZARDS BAY	17	27	23	45	40	37	-15
MA	CHATHAM MUNI ARPT	19	31	27	49	44	41	N/A
MA	LAWRENCE MUNI	46	34	32	54	49	46	-18
MA	MARTHAS VINEYARD	21	31	27	49	44	41	-17
MA	NEW BEDFORD RGNL	25	34	31	53	48	45	-17
MA	NORWOOD MEMORIAL	15	35	32	54	49	46	N/A
MA	OTIS ANGB	40	32	29	51	46	43	-16
MA	PLYMOUTH MUNICIPAL	45	34	31	53	48	45	-18
MA	PROVINCETOWN (AWOS)	2	32	28	50	45	42	-14
MA	SOUTH WEYMOUTH NAS	49	35	32	54	49	46	-19
MA	WORCESTER REGIONAL ARPT	310	32	29	51	46	43	-20
MD	ANDREWS AFB	86	37	34	56	51	48	-15
MD	BALTIMORE BLT-WASHNGTN INT'L	47	37	34	56	51	48	-15
MD	PATUXENT RIVER NAS	12	36	33	55	50	47	-13
MD	SALISBURY WICOMICO CO AP	18	36	33	55	50	47	-14
MD	THOMAS POINT	12	33	30	52	47	44	-10
ME	AUBURN-LEWISTON	88	33	30	52	47	44	-27
ME	AUGUSTA AIRPORT	110	33	30	52	47	44	-23
ME	BANGOR INTERNATIONAL AP	59	33	30	52	47	44	-27
ME	BAR HARBOR (AWOS)	26	30	27	49	44	41	-22
ME	BRUNSWICK NAS	23	33	30	52	47	44	-24
ME	CARIBOU MUNICIPAL ARPT	190	32	28	50	45	42	-31
ME	GREENVILLE (AMOS)	316	30	28	50	45	42	-30
ME	HOULTON INTL ARPT	145	32	29	51	46	43	-32
ME	LORING AFB/LIMESTON	227	32	28	50	45	42	-29
ME	MATINICUS ROCK	27	22	19	41	36	33	-18
ME	MT DESERT ROCK	16	21	18	40	35	32	-18
ME	NORTHERN AROOSTOOK	309	29	27	49	44	41	-28
ME	PORTLAND INTL JETPORT	19	33	30	52	47	44	-23
ME	PRESQUE ISLE MUNICIP	163	31	29	51	46	43	-34
ME	ROCKLAND/KNOX(AWOS)	17	31	27	49	44	41	-21
ME	SANFORD MUNI (AWOS)	74	34	31	53	48	45	-27
ME	WATERVILLE (AWOS)	101	32	29	51	46	43	N/A
ME	WISCASSET	21	32	29	51	46	43	-23
MI	ALPENA COUNTY REGIONAL AP	211	34	30	52	47	44	-26
MI	ANTRIM CO ARPT	190	33	30	52	47	44	-25
MI	BENTON HARBOR/ROSS	196	34	31	53	48	45	-19
MI	CADILLAC WEXFORD CO AP	398	33	30	52	47	44	-29
MI	CHIPPEWA CO INTL	250	31	28	50	45	42	-27
MI	COPPER HARBOR RAMOS	186	31	26	48	43	40	-22
MI	DETROIT CITY AIRPORT	191	35	32	54	49	46	-19
MI	DETROIT METROPOLITAN ARPT	202	35	32	54	49	46	-20
MI	DETROIT WILLOW RUN AP	218	35	32	54	49	46	-20
MI	ESCANABA (AWOS)	187	31	27	49	44	41	-26
MI	FLINT BISHOP INTL ARPT	234	35	31	53	48	45	-23
MI	GRAND RAPIDS KENT COUNTY INT'	245	34	31	53	48	45	-22
MI	GROSSE ISLE ARPT	176	34	31	53	48	45	-16
MI	HANCOCK HOUGHTON CO AP	329	33	28	50	45	42	-24
MI	HARBOR BEACH(RAMOS)	183	35	31	53	48	45	-17
MI	HOLLAND/TULIP CITY	210	33	30	52	47	44	-19
MI	HOUGHTON LAKE ROSCOMMON CO AR	354	33	30	52	47	44	-26
MI	HOWELL	293	34	32	54	49	46	-20
MI	IRON MOUNTAIN/FORD	360	34	30	52	47	44	-29
MI	IRONWOOD (AWOS)	375	33	29	51	46	43	-30
MI	JACKSON REYNOLDS FIELD	311	33	31	53	48	45	-22
MI	KALAMAZOO BATTLE CR	273	34	32	54	49	46	-20
MI	LANSING CAPITAL CITY ARPT	266	34	31	53	48	45	-24
MI	MACKINACK ISLAND	300	33	28	50	45	42	-26

Temperature Table Continued

State	Station	Elev	High Temp (°C)		Distance above roof			Extreme
		(M)	0.4%	2% Avg	0.5"	3.5"	12"	Min (°C)
MI	MANISTEE (AWOS)	189	32	29	51	46	43	-21
MI	MANISTIQUE (AMOS)	178	28	25	47	42	39	-22
MI	MARQUETTE COUNTY ARPT	431	33	29	51	46	43	-30
MI	MENOMINEE (AWOS)	191	33	29	51	46	43	-26
MI	MUSKEGON COUNTY ARPT	193	32	30	52	47	44	-20
MI	NEWBERRY LUCE CO.	265	32	28	50	45	42	-26
MI	OAKLAND CO INTL	306	34	31	53	48	45	-20
MI	OSCODA WURTSMITH AFB	193	35	31	53	48	45	-22
MI	PASSAGE ISLAND	209	22	19	41	36	33	-24
MI	PELLSTON EMMET COUNTY AP	218	33	30	52	47	44	-29
MI	ROCK OF AGES	223	25	21	43	38	35	-26
MI	SAGINAW TRI CITY INTL AP	204	35	32	54	49	46	-21
MI	SAULT STE MARIE SANDERSON FIE	221	32	28	50	45	42	-29
MI	SELFRIDGE ANGB	177	35	32	54	49	46	-20
MI	ST.CLAIR COUNTY INT	198	33	32	54	49	46	-22
MI	STANNARD ROCK	212	26	23	45	40	37	-20
MI	STURGIS\KIRSH MUNI	282	33	32	54	49	46	-21
MI	TRAVERSE CITY CHERRY CAPITAL	192	34	31	53	48	45	-23
MN	AITKIN NDB(AWOS)	367	32	29	51	46	43	-33
MN	ALBERT LEA (AWOS)	383	34	31	53	48	45	-28
MN	ALEXANDRIA MUNICIPAL AP	436	35	31	53	48	45	-31
MN	AUSTIN MUNI	375	34	31	53	48	45	-28
MN	BAUDETTE INTERNATIONAL AP	330	32	29	51	46	43	-35
MN	BEMIDJI MUNICIPAL	420	33	30	52	47	44	-34
MN	BENSON MUNI	317	36	32	54	49	46	-30
MN	BRAINERD/WIELAND	374	34	30	52	47	44	-33
MN	CAMBRIDGE MUNI	287	37	32	54	49	46	-31
MN	CLOQUET (AWOS)	390	33	29	51	46	43	-31
MN	CRANE LAKE (AWOS)	350	33	29	51	46	43	-34
MN	CROOKSTON MUNI FLD	273	32	30	52	47	44	-34
MN	DETROIT LAKES(AWOS)	426	33	30	52	47	44	-32
MN	DULUTH HARBOR (CGS)	186	33	29	51	46	43	-27
MN	DULUTH INTERNATIONAL ARPT	432	32	28	50	45	42	-32
MN	ELY MUNI	455	32	29	51	46	43	-37
MN	EVELETH MUNI (AWOS)	421	33	29	51	46	43	-35
MN	FAIRMONT MUNI(AWOS)	354	33	31	53	48	45	-26
MN	FARIBAULT MUNI AWOS	322	34	31	53	48	45	-29
MN	FERGUS FALLS(AWOS)	361	35	31	53	48	45	-31
MN	FLYING CLOUD	283	35	32	54	49	46	-27
MN	FOSSTON(AWOS)	388	33	30	52	47	44	-35
MN	GLENWOOD (ASOS)	425	36	31	53	48	45	-30
MN	GRAND MARAIS MUNI	548	29	26	48	43	40	-30
MN	GRAND RAPIDS(AWOS)	413	32	28	50	45	42	-32
MN	HALLOCK	250	33	31	53	48	45	-34
MN	HIBBING CHISHOLM-HIBBING AP	414	32	29	51	46	43	-36
MN	HUTCHINSON (AWOS)	323	34	32	54	49	46	-30
MN	INTERNATIONAL FALLS INTL AP	361	32	29	51	46	43	-37
MN	LITCHFIELD MUNI	347	34	31	53	48	45	-28
MN	LITTLE FALLS (AWOS)	342	35	32	54	49	46	-32
MN	MANKATO(AWOS)	311	33	31	53	48	45	-26
MN	MARSHALL/RYAN(AWOS)	359	35	32	54	49	46	-27
MN	MINNEAPOLIS/BLAINE	278	35	32	54	49	46	-26
MN	MINNEAPOLIS/CRYSTAL	265	36	32	54	49	46	-26
MN	MINNEAPOLIS-ST PAUL INT'L ARP	255	36	32	54	49	46	-28
MN	MONTEVIDEO (AWOS)	315	34	32	54	49	46	-28
MN	MORA MUNI (AWOS)	309	33	31	53	48	45	-31
MN	MORRIS MUNI (AWOS)	347	33	31	53	48	45	-30
MN	NEW ULM MUNI (AWOS)	308	34	32	54	49	46	-27
MN	ORR	397	33	29	51	46	43	-35
MN	OWATONNA (AWOS)	350	33	31	53	48	45	-28
MN	PARK RAPIDS MUNICIPAL AP	440	33	30	52	47	44	-34
MN	PEQUOT LAKE (AMOS)	390	36	31	53	48	45	-35
MN	PIPESTONE (AWOS)	529	34	31	53	48	45	-28
MN	PRINCETON MUNI	306	35	31	53	48	45	-29
MN	RED WING	239	35	32	54	49	46	-28
MN	REDWOOD FALLS MUNI	314	36	33	55	50	47	-29
MN	ROCHESTER INTERNATIONAL ARPT	402	33	31	53	48	45	-29
MN	ROSEAU MUNI (AWOS)	323	33	29	51	46	43	-35
MN	SILVER BAY	331	32	28	50	45	42	-34
MN	SOUTH ST PAUL MUNI	250	35	32	54	49	46	-26

Temperature Table Continued

State	Station	Elev	High Temp (°C)		Distance above roof			Extreme
		(M)	0.4%	2% Avg	0.5"	3.5"	12"	Min (°C)
MN	ST CLOUD REGIONAL ARPT	312	35	31	53	48	45	-32
MN	ST JAMES MUNI ARPT	325	34	32	54	49	46	-25
MN	ST PAUL DOWNTOWN AP	217	36	31	53	48	45	-28
MN	THIEF RIVER(AWOS)	340	32	29	51	46	43	-33
MN	TOFTE (RAMOS)	241	29	25	47	42	39	-29
MN	TWO HARBORS	328	32	28	50	45	42	-31
MN	WHEATON NDB (AWOS)	313	33	31	53	48	45	-30
MN	WILLMAR	344	34	31	53	48	45	-31
MN	WINONA MUNI (AWOS)	200	36	32	54	49	46	-28
MN	WORTHINGTON (AWOS)	480	34	31	53	48	45	-26
MO	CAPE GIRARDEAU MUNICIPAL AP	107	37	34	56	51	48	-18
MO	COLUMBIA REGIONAL AIRPORT	274	37	34	56	51	48	-21
MO	JEFFERSON CITY MEM	167	38	35	57	52	49	-19
MO	JOPLIN MUNICIPAL AP	300	37	35	57	52	49	-18
MO	KAISER MEM (AWOS)	265	38	35	57	52	49	-18
MO	KANSAS CITY DOWNTOWN AP	229	38	35	57	52	49	-19
MO	KANSAS CITY INT'L ARPT	312	38	35	57	52	49	-21
MO	KIRKSVILLE REGIONAL AP	294	37	34	56	51	48	-22
MO	POPLAR BLUFF(AMOS)	146	36	34	56	51	48	-16
MO	SEDALIA MEMORIAL	277	38	35	57	52	49	-18
MO	SPICKARD (AMOS)	270	38	35	57	52	49	N/A
MO	SPRINGFIELD REGIONAL ARPT	387	37	34	56	51	48	-19
MO	ST LOUIS LAMBERT INT'L ARPT	216	37	35	57	52	49	-19
MO	ST LOUIS SPIRIT OF ST LOUIS A	141	37	34	56	51	48	-20
MO	VICHY ROLLA NATL ARPT	347	38	34	56	51	48	-19
MO	WHITEMAN AFB	255	38	35	57	52	49	-20
MS	COLUMBUS AFB	68	37	35	57	52	49	-11
MS	GOLDEN TRI(AWOS)	80	37	35	57	52	49	-10
MS	GREENWOOD LEFLORE ARPT	41	37	35	57	52	49	-10
MS	HATTIESBURG LAUREL	93	38	35	57	52	49	-8
MS	JACKSON INTERNATIONAL AP	101	37	35	57	52	49	-9
MS	KEESLER AFB/BILOXI	8	36	34	56	51	48	-6
MS	MCCOMB PIKE COUNTY AP	129	36	34	56	51	48	-8
MS	MERIDIAN KEY FIELD	95	37	35	57	52	49	-10
MS	MERIDIAN NAAS	97	38	36	58	53	50	-11
MS	NATCHEZ/HARDY(AWOS)	83	36	34	56	51	48	-7
MS	TUPELO C D LEMONS ARPT	110	37	35	57	52	49	-12
MT	BILLINGS LOGAN INT'L ARPT	1088	38	34	56	51	48	-27
MT	BOZEMAN GALLATIN FIELD	1356	36	32	54	49	46	-33
MT	BUTTE BERT MOONEY ARPT	1687	34	30	52	47	44	-35
MT	CUT BANK MUNI AP	1170	34	30	52	47	44	-33
MT	DILLON AIRPORT	1592	34	30	52	47	44	-26
MT	GLASGOW INTL ARPT	699	37	34	56	51	48	-33
MT	GLENDIVE(AWOS)	749	38	34	56	51	48	-31
MT	GREAT FALLS	1130	36	31	53	48	45	N/A
MT	GREAT FALLS INTL ARPT	1115	36	32	54	49	46	-31
MT	HAVRE CITY-COUNTY AP	792	37	34	56	51	48	-35
MT	HELENA REGIONAL AIRPORT	1179	37	33	55	50	47	-30
MT	JORDAN (RAMOS)	811	38	35	57	52	49	-37
MT	KALISPELL GLACIER PK INT'L AR	906	35	31	53	48	45	-27
MT	LEWISTOWN MUNICIPAL ARPT	1264	35	31	53	48	45	-31
MT	MALMSTROM AFB	1056	36	33	55	50	47	-30
MT	MILES CITY MUNICIPAL ARPT	803	39	36	58	53	50	-31
MT	MISSOULA INTERNATIONAL AP	972	37	33	55	50	47	-25
MT	SIDNEY-RICHLAND	605	37	33	55	50	47	-32
NC	ASHEVILLE REGIONAL ARPT	661	33	31	53	48	45	-15
NC	CAPE HATTERAS	3	32	30	52	47	44	-4
NC	CAPE LOOKOUT	11	31	29	51	46	43	-6
NC	CHARLOTTE DOUGLAS INTL ARPT	234	37	34	56	51	48	-11
NC	CHERRY POINT MCAS	9	36	33	55	50	47	-9
NC	DIAMOND SHOALS (LS)	0	30	28	50	45	42	-3
NC	FAYETTEVILLE RGNL G	59	38	35	57	52	49	-10
NC	FORT BRAGG/SIMMONS	93	38	35	57	52	49	-10
NC	FRYING PAN SHOALS	24	30	29	51	46	43	-2
NC	GREENSBORO PIEDMONT TRIAD INT	270	35	33	55	50	47	-13
NC	HATTERAS BILLY MITCHELL AP	3	33	31	53	48	45	-6
NC	HICKORY REGIONAL AP	362	36	33	55	50	47	-13
NC	JACKSONVILLE (AWOS)	29	37	34	56	51	48	-11
NC	NEW BERN CRAVEN CO REGL AP	7	36	34	56	51	48	-9
NC	NEW RIVER MCAF	8	36	34	56	51	48	-9

Temperature Table Continued

State	Station	Elev	High Temp (°C)		Distance above roof			Extreme
		(M)	0.4%	2% Avg	0.5"	3.5"	12"	Min (°C)
NC	PITT GREENVILLE ARP	8	37	35	57	52	49	-10
NC	POPE AFB	66	38	36	58	53	50	-10
NC	RALEIGH DURHAM INTERNATIONAL	133	36	34	56	51	48	-12
NC	RICHMOND INTERNATIONAL AP	50	37	34	56	51	48	-13
NC	SEYMOUR-JOHNSON AFB	33	38	35	57	52	49	-10
NC	SOUTHERN PINES AWOS	141	36	34	56	51	48	-13
NC	WILMINGTON INTERNATIONAL ARPT	12	36	34	56	51	48	-9
NC	WINSTON-SALEM REYNOLDS AP	296	36	33	55	50	47	-13
ND	BISMARCK MUNICIPAL ARPT	506	38	33	55	50	47	-33
ND	DEVILS LAKE (AMOS)	443	35	32	54	49	46	-33
ND	DEVILS LAKE(AWOS)	443	33	29	51	46	43	-33
ND	DICKINSON MUNICIPAL AP	787	38	33	55	50	47	-31
ND	FARGO HECTOR INTERNATIONAL AP	274	36	32	54	49	46	-32
ND	GRAND FORKS AFB	276	35	32	54	49	46	-32
ND	GRAND FORKS INTERNATIONAL AP	254	34	31	53	48	45	-33
ND	JAMESTOWN MUNICIPAL ARPT	455	36	32	54	49	46	-31
ND	LIDGERWOOD (RAMOS)	351	38	33	55	50	47	-31
ND	MINOT AFB	497	36	33	55	50	47	-33
ND	MINOT FAA AP	522	35	32	54	49	46	-31
ND	WILLISTON SLOULIN INTL AP	581	37	34	56	51	48	-34
NE	AINSWORTH MUNICIPAL	789	40	34	56	51	48	-26
NE	ALLIANCE MUNICIPAL	1198	39	35	57	52	49	-30
NE	BEATRICE MUNICIPAL	403	39	35	57	52	49	-23
NE	BREWSTER FIELD ARPT	704	38	35	57	52	49	-22
NE	COLUMBUS MUNI	451	37	33	55	50	47	-25
NE	FREMONT MUNI ARPT	379	37	33	55	50	47	N/A
NE	GRAND ISLAND CENTRAL NE REGIO	566	39	35	57	52	49	-25
NE	HASTINGS MUNICIPAL	596	39	35	57	52	49	-23
NE	KEARNEY MUNI (AWOS)	649	38	34	56	51	48	-23
NE	LINCOLN MUNICIPAL ARPT	362	39	35	57	52	49	-24
NE	MCCOOK MUNICIPAL	786	42	38	60	55	52	-22
NE	NORFOLK KARL STEFAN MEM ARPT	473	37	34	56	51	48	-26
NE	NORTH PLATTE REGIONAL AP	850	39	35	57	52	49	-26
NE	O`NEILL/BAKER FIELD	619	39	34	56	51	48	-25
NE	OFFUTT AFB/BELLEVUE	319	38	34	56	51	48	-22
NE	OMAHA EPPLEY AIRFIELD	299	38	34	56	51	48	-24
NE	OMAHA WSFO	399	36	34	56	51	48	-25
NE	SCOTTSBLUFF W B HEILIG FIELD	1206	39	35	57	52	49	-28
NE	SIDNEY MUNICIPAL AP	1313	39	34	56	51	48	-27
NE	TEKAMAH (ASOS)	312	37	34	56	51	48	-26
NE	VALENTINE MILLER FIELD	792	40	36	58	53	50	-29
NH	BERLIN MUNICIPAL	353	31	29	51	46	43	-32
NH	CONCORD MUNICIPAL ARPT	106	34	32	54	49	46	-25
NH	DILLANT HOPKINS	153	33	31	53	48	45	-25
NH	ISLE OF SHOALS	19	29	26	48	43	40	-17
NH	JAFFREY MUNICIPAL	317	32	30	52	47	44	-23
NH	LACONIA MUNI (AWOS)	166	33	31	53	48	45	-24
NH	LEBANON MUNICIPAL	182	34	31	53	48	45	-27
NH	MANCHESTER AIRPORT	71	36	33	55	50	47	-21
NH	MOUNT WASHINGTON	1910	18	16	38	33	30	-36
NH	PEASE INTL TRADEPOR	31	34	31	53	48	45	-19
NJ	ATLANTIC CITY INTL AP	20	36	33	55	50	47	-16
NJ	BELMAR-FARMINGDALE	26	36	32	54	49	46	-14
NJ	CAPE MAY CO	7	34	31	53	48	45	-13
NJ	MCGUIRE AFB	45	36	33	55	50	47	-16
NJ	MILLVILLE MUNICIPAL AP	23	36	33	55	50	47	-17
NJ	NEWARK INTERNATIONAL ARPT	9	37	34	56	51	48	-15
NJ	TETERBORO AIRPORT	2	36	33	55	50	47	-16
NJ	TRENTON MERCER COUNTY AP	65	37	33	55	50	47	N/A
NM	ALAMOGORDO WHITE SA	1313	39	38	60	55	52	N/A
NM	ALBUQUERQUE INTL ARPT	1620	37	35	57	52	49	-12
NM	CANNON AFB/CLOVIS	1309	38	36	58	53	50	-14
NM	CARLSBAD CAVERN CITY AIR TERM	994	41	39	61	56	53	-11
NM	CLAYTON MUNICIPAL AIRPARK	1516	36	34	56	51	48	-19
NM	CLOVIS MUNI (AWOS)	1284	37	35	57	52	49	-14
NM	FARMINGTON FOUR CORNERS REGL	1677	37	34	56	51	48	-17
NM	GALLUP SEN CLARKE FLD	1971	35	32	54	49	46	-23
NM	HOLLOMAN AFB	1248	39	37	59	54	51	-11
NM	ROSWELL INDUSTRIAL AIR PARK	1118	39	37	59	54	51	-13
NM	SIERRA BLANCA RGNL	2078	33	31	53	48	45	-13

Temperature Table Continued

State	Station	Elev	High Temp (°C)		Distance above roof			Extreme
		(M)	0.4%	2% Avg	0.5"	3.5"	12"	Min (°C)
NM	TAOS MUNI APT(AWOS)	2161	33	31	53	48	45	-23
NM	TRUTH OR CONSEQUENCES MUNI AP	1481	38	36	58	53	50	-10
NM	WHITE SANDS	1244	39	37	59	54	51	-12
NV	CALIENTE (AMOS)	1335	39	37	59	54	51	N/A
NV	ELKO MUNICIPAL ARPT	1547	38	34	56	51	48	-24
NV	ELY YELLAND FIELD	1909	35	32	54	49	46	-25
NV	EUREKA (RAMOS)	1993	36	32	54	49	46	-20
NV	FALLON NAAS	1199	39	37	59	54	51	N/A
NV	LAS VEGAS MCCARRAN INTL AP	665	45	42	64	59	56	-4
NV	LOVELOCK DERBY FIELD	1190	40	36	58	53	50	-19
NV	MERCURY DESERT ROCK AP	1009	42	39	61	56	53	-7
NV	NELLIS AFB	573	46	43	65	60	57	-6
NV	RENO TAHOE INTERNATIONAL AP	1341	38	35	57	52	49	-15
NV	TONOPAH AIRPORT	1656	37	35	57	52	49	-17
NV	WINNEMUCCA MUNICIPAL ARPT	1315	39	36	58	53	50	-21
NY	ALBANY COUNTY AP	89	34	31	53	48	45	-23
NY	AMBROSE LIGHT	21	32	28	50	45	42	-13
NY	BINGHAMTON EDWIN A LINK FIELD	499	32	29	51	46	43	-22
NY	BUFFALO NIAGARA INTL AP	215	32	30	52	47	44	-20
NY	DUNKIRK	197	29	27	49	44	41	-16
NY	ELMIRA CORNING REGIONAL AP	291	35	32	54	49	46	-23
NY	FORT DRUM/WHEELER-S	207	32	29	51	46	43	-28
NY	GALLOO ISLAND	76	27	25	47	42	39	-22
NY	GLENS FALLS AP	102	33	31	53	48	45	-29
NY	GRIFFISS AFB	158	34	31	53	48	45	-26
NY	ISLIP LONG ISL MACARTHUR AP	33	34	31	53	48	45	-15
NY	JAMESTOWN (AWOS)	525	31	28	50	45	42	-20
NY	MASSENA AP	65	33	30	52	47	44	-30
NY	MONTICELLO(AWOS)	428	32	29	51	46	43	N/A
NY	NEW YORK J F KENNEDY INT'L AR	7	35	31	53	48	45	-14
NY	NEW YORK LAGUARDIA ARPT	9	36	33	55	50	47	-14
NY	NEWBURGH/STEWART	177	35	31	53	48	45	-20
NY	NIAGARA FALLS AF	179	33	30	52	47	44	-20
NY	PLATTSBURGH AFB	72	32	30	52	47	44	-28
NY	POUGHKEEPSIE DUTCHESS CO AP	49	36	33	55	50	47	-22
NY	REPUBLIC	26	35	32	54	49	46	-13
NY	ROCHESTER GREATER ROCHESTER I	169	34	31	53	48	45	-20
NY	SUPERIOR SHOALS	79	29	27	49	44	41	-23
NY	SYRACUSE HANCOCK INT'L ARPT	127	33	31	53	48	45	-24
NY	UTICA ONEIDA COUNTY AP	227	33	30	52	47	44	-24
NY	WATERTOWN AP	102	31	29	51	46	43	-32
NY	WHITE PLAINS WESTCHESTER CO A	121	35	32	54	49	46	-17
OH	AKRON AKRON-CANTON REG AP	377	34	31	53	48	45	-21
OH	CINCINNATI MUNICIPAL AP LUNKI	152	36	33	55	50	47	-19
OH	CLEVELAND HOPKINS INTL AP	245	34	31	53	48	45	-20
OH	COLUMBUS PORT COLUMBUS INTL A	249	35	32	54	49	46	-20
OH	DAYTON INTERNATIONAL AIRPORT	306	35	32	54	49	46	-21
OH	FINDLAY AIRPORT	248	35	32	54	49	46	-22
OH	LANCASTER\FAIRFIEL	264	34	32	54	49	46	-21
OH	MANSFIELD LAHM MUNICIPAL ARPT	400	33	31	53	48	45	-22
OH	OHIO STATE UNIVERSI	283	34	32	54	49	46	-18
OH	RICKENBACKER ANGB	230	36	33	55	50	47	-19
OH	SOUTH BASS ISLAND	178	31	29	51	46	43	-17
OH	TOLEDO EXPRESS AIRPORT	211	35	32	54	49	46	-21
OH	WRIGHT-PATERSON AFB	250	36	33	55	50	47	-21
OH	YOUNGSTOWN REGIONAL AIRPORT	362	34	31	53	48	45	-21
OH	ZANESVILLE MUNICIPAL AP	275	34	32	54	49	46	-21
OK	ALTUS AFB	414	41	39	61	56	53	-13
OK	CLINTON-SHERMAN	586	41	38	60	55	52	-13
OK	FORT SILL	369	41	37	59	54	51	-13
OK	GAGE AIRPORT	671	39	37	59	54	51	-19
OK	HOBART MUNICIPAL AP	479	41	38	60	55	52	-14
OK	LAWTON MUNICIPAL	338	41	38	60	55	52	-12
OK	MCALESTER MUNICIPAL AP	235	40	36	58	53	50	-14
OK	OKLAHOMA CITY WILL ROGERS WOR	398	40	36	58	53	50	-14
OK	OKLAHOMA CITY/WILEY	396	40	37	59	54	51	-15
OK	PONCA CITY MUNICIPAL AP	304	40	37	59	54	51	-16
OK	STILLWATER RGNL	308	41	37	59	54	51	-15
OK	TINKER AFB	384	39	36	58	53	50	-14
OK	TULSA INTERNATIONAL AIRPORT	206	39	36	58	53	50	-15

Temperature Table Continued

State	Station	Elev	High Temp (°C)		Distance above roof			Extreme
		(M)	0.4%	2% Avg	0.5"	3.5"	12"	Min (°C)
OK	TULSA/LLOYD JONES	193	39	37	59	54	51	-14
OK	VANCE AFB	408	40	37	59	54	51	-16
OR	ASTORIA REGIONAL AIRPORT	7	27	23	45	40	37	-5
OR	AURORA STATE	60	37	32	54	49	46	-5
OR	BAKER MUNICIPAL AP	1028	36	33	55	50	47	-23
OR	BURNS MUNICIPAL ARPT	1271	38	33	55	50	47	-23
OR	CAPE ARAGO (LS)	23	19	17	39	34	31	0
OR	CORVALLIS MUNI	77	38	33	55	50	47	-8
OR	EUGENE MAHLON SWEET ARPT	114	37	32	54	49	46	-8
OR	KLAMATH FALLS INTL AP	1247	35	32	54	49	46	-18
OR	LA GRANDE MUNI AP	828	37	32	54	49	46	-17
OR	LAKEVIEW (AWOS)	1441	34	31	53	48	45	-21
OR	MC MINNVILLE MUNI	51	37	32	54	49	46	-5
OR	MEACHAM	1136	33	30	52	47	44	-28
OR	MEDFORD ROGUE VALLEY INTL AP	405	40	36	58	53	50	-8
OR	NEWPORT STATE BEACH	11	18	17	39	34	31	-2
OR	NORTH BEND MUNI AIRPORT	5	22	20	42	37	34	-4
OR	PENDLETON E OR REGIONAL AP	462	39	35	57	52	49	-16
OR	PORTLAND INTERNATIONAL AP	33	36	32	54	49	46	-6
OR	PORTLAND/HILLSBORO	62	37	32	54	49	46	-8
OR	REDMOND ROBERTS FIELD	940	37	33	55	50	47	-19
OR	SALEM MCNARY FIELD	61	37	32	54	49	46	-8
OR	SEXTON SUMMIT	1171	32	28	50	45	42	-8
PA	ALLENTOWN LEHIGH VALLEY INTL	117	35	32	54	49	46	-17
PA	ALTOONA BLAIR CO ARPT	448	34	31	53	48	45	-19
PA	BRADFORD REGIONAL AP	655	31	28	50	45	42	-25
PA	BUTLER CO. (AWOS)	380	33	31	53	48	45	-19
PA	DUBOIS FAA AP	556	32	29	51	46	43	-22
PA	ERIE INTERNATIONAL AP	225	32	30	52	47	44	-18
PA	FRANKLIN	469	31	29	51	46	43	-20
PA	HARRISBURG CAPITAL CITY ARPT	106	37	33	55	50	47	-17
PA	JOHNSTOWN CAMBRIA COUNTY AP	696	32	29	51	46	43	-20
PA	MIDDLETOWN HARRISBURG INTL AP	95	37	33	55	50	47	-15
PA	PHILADELPHIA INTERNATIONAL AP	9	36	34	56	51	48	-14
PA	PHILADELPHIA NE PHILADELPHIA	36	37	33	55	50	47	-15
PA	PITTSBURGH ALLEGHENY CO AP	388	34	32	54	49	46	-20
PA	PITTSBURGH INTERNATIONAL AP	367	34	31	53	48	45	-20
PA	READING SPAATZ FIELD	108	37	33	55	50	47	N/A
PA	WASHINGTON (AWOS)	361	33	31	53	48	45	N/A
PA	WILKES-BARRE SCRANTON INTL AP	293	34	31	53	48	45	-19
PA	WILLIAMSPORT REGIONAL AP	160	36	32	54	49	46	-19
PA	WILLOW GROVE NAS	110	36	33	55	50	47	-17
RI	BLOCK ISLAND STATE ARPT	33	31	27	49	44	41	-14
RI	PAWTUCKET (AWOS)	134	33	30	52	47	44	N/A
RI	PROVIDENCE T F GREEN STATE AR	19	35	32	54	49	46	-17
SC	ANDERSON COUNTY AP	236	37	34	56	51	48	-10
SC	BEAUFORT MCAS	12	37	34	56	51	48	-6
SC	CHARLESTON INTL ARPT	15	37	34	56	51	48	-7
SC	COLUMBIA METRO ARPT	69	38	36	58	53	50	-10
SC	FLORENCE REGIONAL AP	46	38	35	57	52	49	-9
SC	FOLLY ISLAND	5	33	30	52	47	44	-3
SC	GREER GREENV'L-SPARTANBRG AP	296	37	34	56	51	48	-11
SC	MYRTLE BEACH AFB	8	36	33	55	50	47	-8
SC	SHAW AFB/SUMTER	74	38	35	57	52	49	-9
SD	ABERDEEN REGIONAL ARPT	396	38	33	55	50	47	-32
SD	BROOKINGS (AWOS)	502	34	31	53	48	45	-30
SD	BUFFALO (AMOS)	915	40	34	56	51	48	-29
SD	CHAMBERLAIN (AMOS)	530	41	35	57	52	49	-27
SD	CHAN GURNEY MUNI	408	38	33	55	50	47	-25
SD	CUSTER (RAMOS)	1707	34	30	52	47	44	-28
SD	ELLSWORTH AFB	980	39	35	57	52	49	-26
SD	HURON REGIONAL ARPT	393	38	34	56	51	48	-30
SD	MITCHELL (AWOS)	397	39	34	56	51	48	-27
SD	MOBRIDGE	508	39	34	56	51	48	-30
SD	PIERRE MUNICIPAL AP	526	41	36	58	53	50	-28
SD	RAPID CITY REGIONAL ARPT	966	40	35	57	52	49	-27
SD	SIOUX FALLS FOSS FIELD	435	37	33	55	50	47	-29
SD	WATERTOWN MUNICIPAL AP	530	36	32	54	49	46	-29
TN	BRISTOL TRI CITY AIRPORT	465	34	32	54	49	46	-17
TN	CHATTANOOGA LOVELL FIELD AP	210	37	34	56	51	48	-12

Temperature Table Continued

State	Station	Elev	High Temp (°C)		Distance above roof			Extreme
		(M)	0.4%	2% Avg	0.5"	3.5"	12"	Min (°C)
TN	CROSSVILLE MEMORIAL AP	570	33	31	53	48	45	-18
TN	DYERSBURG MUNICIPAL AP	103	36	34	56	51	48	-12
TN	JACKSON MCKELLAR-SIPES REGL A	129	36	34	56	51	48	-15
TN	KNOXVILLE MCGHEE TYSON AP	299	36	33	55	50	47	-15
TN	MEMPHIS INTERNATIONAL AP	101	37	35	57	52	49	-12
TN	MILLINGTON MUNI ARP	98	38	36	58	53	50	-14
TN	NASHVILLE INTERNATIONAL AP	184	37	34	56	51	48	-15
TX	ABILENE DYESS AFB	545	40	38	60	55	52	-12
TX	ABILENE REGIONAL AP	546	39	37	59	54	51	-11
TX	ALICE INTL AP	55	39	37	59	54	51	-2
TX	AMARILLO INTERNATIONAL AP	1099	38	36	58	53	50	-17
TX	AUSTIN/BERGSTROM	151	39	37	59	54	51	-7
TX	BEEVILLE CHASE NAAS	58	39	37	59	54	51	-5
TX	BROWNSVILLE S PADRE ISL INTL	7	36	35	57	52	49	0
TX	BURNET MUNI.	391	38	36	58	53	50	-6
TX	CAMP MABRY	201	39	37	59	54	51	-5
TX	CHILDRESS MUNICIPAL AP	595	40	38	60	55	52	-12
TX	COLLEGE STATION EASTERWOOD FL	100	38	37	59	54	51	-6
TX	CORPUS CHRISTI INTL ARPT	13	36	35	57	52	49	-3
TX	CORPUS CHRISTI NAS	6	34	34	56	51	48	-1
TX	COTULLA FAA AP	146	41	39	61	56	53	-4
TX	COX FLD	171	38	36	58	53	50	-10
TX	DALHART MUNICIPAL AP	1217	38	36	58	53	50	-17
TX	DALLAS HENSLEY FIELD NAS	151	39	37	59	54	51	-9
TX	DALLAS LOVE FIELD	149	39	37	59	54	51	-8
TX	DALLAS/REDBIRD ARPT	201	40	37	59	54	51	-8
TX	DALLAS-FORT WORTH INTL AP	182	39	37	59	54	51	-9
TX	DEL RIO INTERNATIONAL AP	313	40	38	60	55	52	-4
TX	DRAUGHON MILLER CEN	213	39	37	59	54	51	-7
TX	EL PASO INTERNATIONAL AP	1194	40	38	60	55	52	-9
TX	FORT HOOD/GRAY AAF	312	39	37	59	54	51	-8
TX	FORT STOCKTON PECOS	941	39	38	60	55	52	-8
TX	FORT WORTH ALLIANCE	226	40	38	60	55	52	-9
TX	FORT WORTH MEACHAM	215	40	37	59	54	51	-10
TX	FORT WORTH NAS	198	40	37	59	54	51	-10
TX	GALVESTON/SCHOLES	3	34	33	55	50	47	-2
TX	GEORGETOWN (AWOS)	240	38	36	58	53	50	-7
TX	HARLINGEN RIO GRANDE VALLEY I	11	38	37	59	54	51	0
TX	HONDO MUNICIPAL AP	284	38	37	59	54	51	-7
TX	HOUSTON BUSH INTERCONTINENTAL	32	37	35	57	52	49	-4
TX	HOUSTON WILLIAM P HOBBY AP	14	36	35	57	52	49	-3
TX	HOUSTON/D.W. HOOKS	46	38	36	58	53	50	-4
TX	HOUSTON/ELLINGTON	12	37	35	57	52	49	-3
TX	JUNCTION KIMBLE COUNTY AP	533	39	37	59	54	51	-10
TX	KELLY AFB	208	39	37	59	54	51	-6
TX	KILLEEN MUNI (AWOS)	258	39	37	59	54	51	-6
TX	KINGSVILLE	18	37	36	58	53	50	-3
TX	LAREDO INTL AIRPORT	155	40	39	61	56	53	-2
TX	LAUGHLIN AFB	327	42	39	61	56	53	-5
TX	LONGVIEW GREGG COUNTY AP	114	39	36	58	53	50	-8
TX	LUBBOCK INTERNATIONAL AP	988	39	36	58	53	50	-14
TX	LUFKIN ANGELINA CO	96	38	36	58	53	50	-7
TX	MARFA AP	1478	36	34	56	51	48	-14
TX	MC GREGOR (AWOS)	180	39	37	59	54	51	-7
TX	MCALLEN MILLER INTL AP	34	39	37	59	54	51	0
TX	MCKINNEY MUNI ARPT	176	39	37	59	54	51	-10
TX	MIDLAND INTERNATIONAL AP	872	40	37	59	54	51	-11
TX	NACOGDOCHES (AWOS)	108	38	36	58	53	50	-7
TX	PALACIOS MUNICIPAL AP	5	34	33	55	50	47	-3
TX	PINE SPRINGS GUADALUPE MOUNTA	1663	36	33	55	50	47	-12
TX	PORT ARANSAS	6	30	30	52	47	44	0
TX	PORT ARTHUR JEFFERSON COUNTY	5	35	34	56	51	48	-4
TX	RANDOLPH AFB	232	39	37	59	54	51	-6
TX	REESE AFB	1014	40	37	59	54	51	-14
TX	ROCKPORT/ARANSAS CO	8	34	33	55	50	47	0
TX	SABINE	6	32	31	53	48	45	-3
TX	SAN ANGELO MATHIS FIELD	577	40	37	59	54	51	-10
TX	SAN ANTONIO INTL AP	247	38	36	58	53	50	-6
TX	SAN ANTONIO/STINSON	176	39	37	59	54	51	-4
TX	SAN MARCOS MUNI	182	38	37	59	54	51	-5

Temperature Table Continued

State	Station	Elev	High Temp (°C)		Distance above roof			Extreme
		(M)	0.4%	2% Avg	0.5"	3.5"	12"	Min (°C)
TX	SANDERSON (RAMOS)	865	39	36	58	53	50	-8
TX	STEPHENVILLE CLARK FIELD	403	38	36	58	53	50	-10
TX	VICTORIA REGIONAL AP	36	37	35	57	52	49	-4
TX	WACO REGIONAL AP	155	39	37	59	54	51	-8
TX	WICHITA FALLS MUNICIPAL ARPT	314	41	38	60	55	52	-12
TX	WINK WINKLER COUNTY AP	860	42	40	62	57	54	-11
UT	CEDAR CITY MUNICIPAL AP	1712	37	34	56	51	48	-21
UT	HILL AFB/OGDEN	1459	37	33	55	50	47	-16
UT	LOGAN-CACHE AIRPORT	1358	38	34	56	51	48	-24
UT	MILFORD MUNICIPAL AP	1534	39	35	57	52	49	-22
UT	PRICE/CARBON COUNTY	1799	36	33	55	50	47	-19
UT	PROVO MUNI (AWOS)	1369	38	34	56	51	48	-15
UT	SAINT GEORGE (AWOS)	896	44	41	63	58	55	-6
UT	SALT LAKE CITY INT'L ARPT	1288	39	36	58	53	50	-16
UT	VERNAL	1608	37	33	55	50	47	-20
UT	WENDOVER USAF AUXILIARY FIELD	1291	38	35	57	52	49	-16
VA	ABINGTON	631	32	31	53	48	45	-16
VA	CHESAPEAKE	23	31	28	50	45	42	-8
VA	DANVILLE FAA AP	180	36	34	56	51	48	-12
VA	DINWIDDIE CO	60	38	36	58	53	50	-14
VA	FARMVILLE	125	37	34	56	51	48	-16
VA	FORT BELVOIR/DAVISO	27	38	35	57	52	49	-17
VA	HILLSVILLE	834	31	29	51	46	43	-15
VA	HOT SPRINGS/INGALLS	1156	31	28	50	45	42	-19
VA	LANGLEY AFB/HAMPTON	3	36	33	55	50	47	-10
VA	LEESBURG/GODFREY	119	37	34	56	51	48	-14
VA	LYNCHBURG REGIONAL ARPT	286	35	33	55	50	47	-15
VA	MANASSAS MUNI(AWOS)	59	36	33	55	50	47	-16
VA	MARION / WYTHEVILLE	780	33	32	54	49	46	-17
VA	MARTINSVILLE	287	36	34	56	51	48	-15
VA	MECKLENBURG\BRUNS.	430	37	34	56	51	48	N/A
VA	MELFA/ACCOMACK ARPT	15	36	34	56	51	48	N/A
VA	NEWPORT NEWS	16	37	34	56	51	48	-11
VA	NORFOLK INTERNATIONAL AP	9	36	34	56	51	48	-9
VA	NORFOLK NAS	5	37	34	56	51	48	-9
VA	OCEANA NAS	7	36	33	55	50	47	-10
VA	QUANTICO MCAS	4	36	33	55	50	47	-13
VA	ROANOKE REGIONAL AP	358	36	33	55	50	47	-14
VA	SHANNON ARPT	26	37	35	57	52	49	-15
VA	STAUNTON/SHENANDOAH	366	37	34	56	51	48	-17
VA	VIRGINIA TECH ARPT	650	33	31	53	48	45	-15
VA	WALLOPS ISLAND UAU	15	35	32	54	49	46	-11
VA	WASHINGTON DC DULLES INT'L AR	99	36	34	56	51	48	-17
VA	WASHINGTON DC REAGAN AP	20	37	34	56	51	48	-12
VA	WINCHESTER RGNL	222	37	34	56	51	48	-15
VA	WISE/LONESOME PINE	817	31	29	51	46	43	N/A
VT	BURLINGTON INTERNATIONAL AP	104	34	31	53	48	45	-26
VT	MONTPELIER AP	342	32	29	51	46	43	-28
VT	MORRISVILLE\STONE	223	31	29	51	46	43	-28
VT	RUTLAND STATE	246	31	29	51	46	43	-26
VT	SPRINGFIELD/HARTNES	176	33	31	53	48	45	-25
WA	ARLINGTON MUNI	42	32	27	49	44	41	-9
WA	BELLINGHAM INTL AP	46	29	26	48	43	40	-10
WA	BREMERTON NATIONAL	137	34	29	51	46	43	-8
WA	DESTRUCTION ISLAND	39	19	17	39	34	31	-2
WA	FAIRCHILD AFB	743	36	32	54	49	46	-19
WA	FELTS FLD	610	38	34	56	51	48	-17
WA	FRIDAY HARBOR	33	29	25	47	42	39	-5
WA	GRAY AAF	92	34	29	51	46	43	-10
WA	HANFORD	223	41	37	59	54	51	-16
WA	HOQUIAM AP	5	28	23	45	40	37	-4
WA	KELSO WB AP	6	35	29	51	46	43	-8
WA	MC CHORD AFB/TACOMA	88	34	29	51	46	43	-10
WA	OLYMPIA AIRPORT	61	35	30	52	47	44	-11
WA	OMAK	382	39	35	57	52	49	-16
WA	PASCO	123	41	36	58	53	50	-17
WA	PEARSON FLD	8	37	32	54	49	46	-7
WA	PULLMAN/MOSCOW RGNL	778	36	32	54	49	46	-18
WA	QUILLAYUTE STATE AIRPORT	63	29	25	47	42	39	-7
WA	SEATTLE BOEING FIELD	9	33	29	51	46	43	-7

Temperature Table Continued

State	Station	Elev	High Temp (°C)		Distance above roof			Extreme
		(M)	0.4%	2% Avg	0.5"	3.5"	12"	Min (°C)
WA	SEATTLE SEATTLE-TACOMA INTL A	132	33	29	51	46	43	-6
WA	SHELTON/SANDERSON	82	35	30	52	47	44	-7
WA	SMITH ISLAND	18	22	18	40	35	32	-3
WA	SNOHOMISH CO	189	30	26	48	43	40	-5
WA	SPOKANE INTERNATIONAL AP	721	37	33	55	50	47	-20
WA	STAMPEDE PASS	1209	29	25	47	42	39	-15
WA	TACOMA NARROWS	91	33	28	50	45	42	-4
WA	TATOOSH ISLAND	48	19	17	39	34	31	-2
WA	WALLA WALLA CITY COUNTY AP	367	41	36	58	53	50	-14
WA	WENATCHEE/PANGBORN	375	38	34	56	51	48	-16
WA	WEST POINT (LS)	9	24	21	43	38	35	-3
WA	WHIDBEY ISLAND NAS	14	25	22	44	39	36	-9
WA	WILLIAM R FAIRCHILD	91	30	25	47	42	39	-6
WA	YAKIMA AIR TERMINAL	325	38	34	56	51	48	-18
WI	ANTIGO\LANG(AWOS)	464	33	29	51	46	43	N/A
WI	APPLETON/OUTAGAMIE	280	35	31	53	48	45	-24
WI	DEVILS ISLAND	211	30	25	47	42	39	-24
WI	EAGLE RIVER UNION	500	32	28	50	45	42	-31
WI	EAU CLAIRE COUNTY AP	273	36	32	54	49	46	-30
WI	FOND DU LAC CO.	246	34	31	53	48	45	-24
WI	GREEN BAY AUSTIN STRAUBEL INT	214	34	31	53	48	45	-27
WI	HAYWARD MUNI ARPT	370	36	30	52	47	44	-32
WI	JUNEAU\DODGE CO	285	33	30	52	47	44	-23
WI	KENOSHA RGNL	232	36	32	54	49	46	-23
WI	LA CROSSE MUNICIPAL ARPT	200	36	33	55	50	47	-27
WI	MADISON DANE CO REGIONAL ARPT	264	34	32	54	49	46	-26
WI	MANITOWAC MUNI AWOS	198	33	29	51	46	43	-23
WI	MARSHFIELD MUNI	389	35	30	52	47	44	-27
WI	MILWAUKEE MITCHELL INTL AP	211	35	32	54	49	46	-24
WI	MOSINEE/CENTRAL WI	389	34	30	52	47	44	-28
WI	PARK FALLS MUNI	469	31	29	51	46	43	N/A
WI	PHILLIPS/PRICE CO.	449	33	29	51	46	43	-32
WI	RHINELANDER ONEIDA	507	33	29	51	46	43	-30
WI	RICE LAKE MUNICIPAL	347	34	30	52	47	44	-29
WI	SHEBOYGAN	228	34	30	52	47	44	N/A
WI	SHEBOYGAN	189	32	28	50	45	42	-22
WI	STURGEON BAY	221	32	28	50	45	42	-24
WI	WATERTOWN	254	34	31	53	48	45	-25
WI	WAUSAU MUNICIPAL ARPT	365	34	31	53	48	45	-29
WI	WISCONSIN RAPIDS	308	34	31	53	48	45	-27
WI	WITTMAN RGNL	253	34	31	53	48	45	-24
WV	BECKLEY RALEIGH CO MEM AP	766	31	29	51	46	43	-20
WV	BLUEFIELD/MERCER CO	874	31	29	51	46	43	-19
WV	CHARLESTON YEAGER ARPT	299	35	32	54	49	46	-18
WV	ELKINS ELKINS-RANDOLPH CO ARP	603	32	30	52	47	44	-24
WV	HARRISON MARION RGN	380	33	32	54	49	46	-17
WV	HUNTINGTON TRI-STATE ARPT	255	35	33	55	50	47	-18
WV	MARTINSBURG EASTERN WV REG AP	163	37	33	55	50	47	-18
WV	MORGANTOWN HART FIELD	382	34	31	53	48	45	-19
WV	PARKERSBURG WOOD COUNTY AP	263	35	32	54	49	46	-19
WY	BIG PINEY (AMOS)	2126	32	29	51	46	43	-33
WY	CASPER NATRONA CO INTL AP	1612	37	34	56	51	48	-29
WY	CHEYENNE MUNICIPAL ARPT	1872	34	31	53	48	45	-26
WY	CODY MUNI (AWOS)	1553	36	32	54	49	46	-28
WY	GILLETTE/GILLETTE-C	1230	38	34	56	51	48	-28
WY	JACKSON HOLE	2016	32	28	50	45	42	-31
WY	LANDER HUNT FIELD	1694	36	33	55	50	47	-27
WY	LARAMIE GENERAL BREES FIELD	2217	32	29	51	46	43	-31
WY	ROCK SPRINGS ARPT	2056	34	30	52	47	44	-26
WY	SHERIDAN COUNTY ARPT	1209	38	34	56	51	48	-29
WY	WORLAND MUNICIPAL	1283	39	35	57	52	49	-34
WY	YELLOWSTONE LAKE (RAMOS)	2388	27	24	46	41	38	-33

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ABCS-11-SR

A Comprehensive Review of Solar Access Law in the United States

Suggested Standards for a Model Statue and Ordinance

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October 2008

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Executive Summary

Solar energy systems require direct access to sunlight to operate efficiently. The installation of a solar energy system on a new or existing building requires exterior modifications that are subject to building codes and private regulation. This report reviews the ability of existing law and regulation to protect solar access and recommends specific measures to improve solar access.

The solar access issue will be separated into two distinct areas: solar easements and solar rights. "Solar easements" refers to the ability of one property to continue to receive sunlight across property lines without obstruction from another's property (buildings, foliage, or other impediment). "Solar rights" refers to the ability to install solar energy systems on residential and commercial property that is subject to private restrictions, i.e., covenants, conditions, restrictions, bylaws, condominium declarations, as well as local government ordinances and building codes.

The United States has held that there is no common-law right to sunlight. This has required that specific statutory authority be established to protect the rights of solar users in terms of both their ability to install a solar energy system on their property and after that system is installed to protect their access to sunlight, so that the system remains operational.

Land use planning, authority for solar easements, and prohibiting covenants, conditions, and restrictions that impede the use of solar have all been employed to protect solar access with varying degrees of success. This report reviews traditional legal mechanisms that govern the operation of public and private governments, as well as solar specific ordinances and statutes that have evolved over the years. It concludes that most current law has been ineffective or too expensive because of the lack of enforcement mechanisms.

The recommended elements of a comprehensive approach to protecting solar access are outlined, and a model solar statute has been developed based upon the best practices found across the United States. The model statute is intended to serve initially as a *straw man* for discussion among stakeholders and will be revised to reflect feedback based upon their needs. The statutory references that constitute the best practices are provided in the appendix to facilitate discussion and feedback from stakeholders.

Author Biography

Colleen Kettles is the Executive Director of the Florida Solar Energy Research and Education Foundation. She formerly served as the Associate General Counsel and Director of Institutional Affairs for the Florida Solar Energy Center. Colleen has 30 years of legal and policy research, program development, and implementation in the field of solar energy and energy efficiency. Colleen has also served as a contractor to the Florida Energy Office, Florida Solar Energy Center, National Renewable Energy Laboratory, and Department of Energy. She has provided policy analysis for issues before the Florida Public Service Commission and committees of the Florida Legislature on matters related to solar energy. She has published and presented numerous papers on the range of issues dealing with solar energy and energy efficiency policy. Colleen is a graduate of the University of Florida College of Law and is a member of the Florida Bar and the American Bar Association. She serves on the board of directors of the Florida Solar Energy Industries Association and the Florida Renewable Energy Association, and was a founding director of the Florida Green Building Coalition.

Florida Solar Energy Research and Education Foundation Web site:
www.flaseref.org

Solar America Board for Codes and Standards

The Solar America Board for Codes and Standards (Solar ABCs) is a collaborative effort among experts to formally gather and prioritize input from the broad spectrum of solar photovoltaic stakeholders including policy makers, manufacturers, installers, and consumers resulting in coordinated recommendations to codes and standards making bodies for existing and new solar technologies. The U.S. Department of Energy funds Solar ABCs as part of its commitment to facilitate wide-spread adoption of safe, reliable, and cost-effective solar technologies.

For more information, visit the Solar ABCs Web site:
www.solarabcs.org

Acknowledgement:

This material is based upon work supported by the Department of Energy under Award Number DE-FC36-07GO17034.

Table of Contents

Disclaimer ii

Executive Summary iii

Author's Biography iv

Solar ABCs iv

Acknowledgements iv

Introduction 1

- Solar access 1
- Historical perspective 1
  - The Doctrine of Ancient Lights 1
  - The Fontainebleau Case 2
- Early efforts to address solar access 2
- Land use planning 2
- Solar Easements 3
  - Covenants, Conditions, and Restrictions 3
  - Express termination 4
  - Modification 4
  - Cancellation 5
  - Local ordinances 5

Analysis of state solar access laws 6

- Solar easement statutes 6
- Solar rights 6
- Typical cases 7

Exemplary solar access laws 8

- City of Gainesville, Florida 8
- State of Hawaii 8
- State of Massachusetts 8
- State of New Jersey 9
- State of New Mexico 9
- City of Ashland, Oregon 9
- Virgin Islands 9
- State of Wisconsin 10

Recommendation 10

Components of solar access legislation 10

Model Statute/Ordinance to Encourage Access to Solar Energy 12

References 15

Appendix 16

Introduction

Solar energy systems, whether thermal or photovoltaic, require direct access to sunlight to operate efficiently. The installation of a solar energy system on a new or existing building requires exterior modifications that are subject to building codes and private regulation. As our energy policies shift to advancing solar energy as a significant source of our energy portfolio, the conventional view of building codes and restrictive covenants must yield to guaranteeing access to sunlight to the fullest extent possible.

This report is divided into several sections. The first reviews common law and conventional statutes that might serve to protect solar access. The second reviews modern day efforts to afford access to sunlight through solar easements and solar rights. Finally, in developing a model solar access statute, we identify the best practices employed by state and local government and provide a recommended model. The appendix provides the full text of the statutes that were used in developing the model, and can be referred to in the event that more detail is desired in the model statute adopted for implementation.

Solar Access

The solar access issue is generally thought to involve the potential shading of solar collectors by neighboring structures or vegetation. There is, however, another aspect to the solar access issue: public and private restrictions on the use of property, including restrictive covenants in deeds, condominium and homeowner association bylaws, architectural controls, and local government ordinances.

For discussion purposes, the issue of solar access in this report is separated into two clearly defined areas: solar easements and solar rights. "Solar easements" refers to the ability of one property to continue to receive sunlight across property lines without obstruction from another's property (buildings, foliage, or other impediment). "Solar rights" refers to the ability to install solar energy systems on residential and commercial property that is subject to private restrictions, i.e., covenants, conditions, restrictions, bylaws, condominium declarations, as well as local government ordinances and building codes.

Historical Perspective

The Doctrine of Ancient Lights

"Ancient Lights" is a doctrine based on English law that refers to a negative easement that prevents the owner or occupier of an adjoining structure from building or placing on his own land anything that has the effect of obstructing the light of the dominant tenement. In common law, a person who opened a window in his house had a natural right to receive the flow of light that passed through it. Quite literally, when a window had been opened for so long a time as to constitute immemorial usage in law, the light became an "ancient light" that the law protected from disturbance. The Prescription Act of 1832 created a statutory prescription for light. It provided that

> *when the access and use of light to and for (any building) shall have been actually enjoyed therewith for the full period of 20 years without interruption, the right thereto shall be deemed absolute and indefeasible, any local usage or custom to the contrary notwithstanding, unless it shall appear that the same was enjoyed by some consent or agreement, expressly made or given for that purpose by deed or writing (UK Statute Law Database).*

The Fontainebleau Case

The Sunshine State—Florida—has the dubious distinction of formalizing the rejection of the Ancient Lights doctrine and pronouncing that there is no common law right to sunlight. The leading case in America on the right to sunlight is Fontainebleau Hotel Corp. v. Forty-Five Twenty-Five, Inc. (Fontainebleau Hotel Corp., 1959). In this case, the Fontainebleau Hotel in Miami Beach proposed a 14-story addition in the late 1950s. The Eden Roc Hotel, which was located immediately adjacent to the Fontainebleau, objected to this addition. They claimed that during the winter months, from approximately 2 p.m. to sunset, the shadow of the proposed addition would extend over the cabana, swimming pool, and sunbathing areas of the Eden Roc.

They also contended that the addition would interfere with the light and air on the beach in front of the Eden Roc and cast a shadow of such size as to render the beach wholly unfit for the use and enjoyment of the guests of the Eden Roc. In addition, it was charged that one of the reasons for the construction was actual malice and ill will on the part of the President of the Fontainebleau toward the President of the Eden Roc.

The trial court ruled in favor of the Eden Roc on the grounds that no person has a right to use his property to the injury of another (Caton & Kettles, 1980). However, that decision was reversed on appeal and construction was allowed to continue. Several principles of law were set forth by the Third District that are still followed today and laid the groundwork for some of the principles of solar law. The principles established by this court are as follows:

- A property owner must never use his property so as to injure the lawful rights of another. A property owner may put his own property to any reasonable and lawful use, so long as he does not thereby deprive the adjoining landowner of any right of enjoyment of his property that is recognized and protected by law and as long as his use is not such a one as the law will pronounce a nuisance.
- A landowner does not have any legal right to the free flow of light and air across the adjoining land of his neighbor.
- The English doctrine of Ancient Lights has been unanimously repudiated in other states where that question has arisen and has no validity in Florida.
- Because there is no legal right to the free flow of light and air from the adjoining land, there is no cause of action for nuisance, damages, or injunctive relief even though a building or structure interferes with the passage of light and air to adjoining premises.

Early efforts to address solar access

During the height of the 1978-1985 tax credits for solar energy equipment, a host of articles and books were published promoting solar conscious land use planning (Kraemer, 1978). While not widely adopted, these guidelines provided some excellent and well thought out approaches to protecting solar access in new home construction. These guidelines remain useful today but will typically only apply to new construction and not address the vast inventory of existing homes and neighborhoods.

Land use planning

Local governments have the ability to adopt solar-access policies within the framework of the local comprehensive and land use plans. A policy statement recognizing the benefits of solar energy and supporting public regulations to promote these benefits establishes the public purpose and validity of such actions. Incorporating solar-site planning in land use planning allows the developer to maximize southern exposures so

that as many buildings and lots as possible can have maximum access to sunlight. Trees, major vegetation, and taller buildings must be placed in such a way that the shadowing of adjacent residential structures will be minimized. In the site-planning process, a developer can provide that the solar sky space above neighboring parcels of land will remain clear and unobstructed to preserve solar access. One way to accomplish this objective is to provide for solar easements, which are defined as restrictions on adjoining lots that would prohibit intrusions into the solar sky space, such as another building or trees. A restrictive covenant can accomplish this as well by providing that no solar energy collector shall be shaded by any building, vegetation, or obstruction between certain hours on a certain date of any year.

Landscape ordinances can be modified to promote vegetation that complements solar energy use or provides exemptions for trees and vegetation that block solar access.

Solar Easements

A solar easement is the prevalent method of assuring solar access. The general principle of law in effect in the US is that a land owner owns at least as much of the air space above the ground as he can occupy or use in connection with the land, and the fact that he does not occupy it in a physical sense by erection of buildings and the like is not material (Caton, 1980). Because the property owner does have property rights in the air space above the land, he has the right to grant an easement for light within that air space. However, an easement for light and air cannot be created by implication nor can it be implied by any length of continuous enjoyment (Caton, 1980). This decision further eroded the doctrine of Ancient Lights and resulted in the need for statutory authority for modern solar easements (Caton, 1980).

Covenants, Conditions, and Restrictions

Condominium and homeowner associations are fairly common entities in residential communities today. The associations generally govern the affairs of the community and, in addition to enforcing and amending restrictive covenants, may impose other restrictions on property owners subject to their rules.

The condominium association is a corporate entity and has the authority to govern its affairs in accordance with a set of duly adopted bylaws. The bylaws of a condominium association are included in the declaration of condominium, the provisions of which are considered binding agreements that run with the land. Generally, condominium bylaws will not be invalidated unless their application is arbitrary, they are in violation of public policy, or they infringe upon a constitutional right. Where the bylaws empower the board of directors of the association with discretionary authority, such as architectural review and approval, its action must be reasonably related to the promotion of the health, happiness, and peace of mind of the unit owners. In addition, the courts have held that where the decision to allow a particular use is within the discretion of the board, the use must be allowed unless it can be demonstrated to be antagonistic to the legitimate objectives of the association.

A homeowners association is an organization consisting of property owners within a subdivision that has been granted or assumes certain powers and is in essence residential private government. Its authority and powers are contained in a variety of documents, including restrictive covenants and bylaws. Restrictive covenants are mutual agreements contained in deeds to real property. They are typically part of planned communities and subdivisions where the developer has stipulated the architectural form and general scheme of construction in the community. These restrictions are not personal in nature but rather are considered to “run with the land.” That is, they are effective against all subsequent owners of the affected property.

The most frequently found restrictive covenants relating to the use of solar energy include restrictions on where collectors may be located (e.g., a place other than on the front of the house), those that require board-of-architect approval as a condition precedent to external structural alterations (such as the installation of the solar collectors anywhere on the house), prohibitions against protrusions above roof level (television antennas are the usual subject of these restrictions but they can also affect roof-mounted solar collectors), or an outright prohibition of solar systems.

Homeowner association bylaws often contain the details as to how the powers of the association will be exercised and will often include the specifics of the guidelines to be followed by architectural review boards. Regarding the validity of homeowner association bylaws, it has been suggested that the power of the association is without limit, although basic consideration regarding the validity of use restrictions may still be relied upon.

Courts have long held restrictive covenants to be valid exceptions to the general principle against restraint on free use of property. Judicial acceptance of restrictive covenants is premised on the supposition that such recognition is not contrary to public policy or express law. The restriction must also be reasonable. A subdivision's restrictive covenant that effectively or directly prohibits the use of solar will not be upheld where state or local law expressly provides otherwise through a solar-rights statute or ordinance. If the restrictive covenant precedes the effective date of the statute or ordinance, the restriction may be invalidated by the court based on public policy considerations.

In the absence of a solar-rights law, it may still be possible for a homeowner to overcome a restrictive covenant that prohibits the use of solar energy. The deed that conveyed the covenant may stipulate a time of expiration for the restriction. In addition, the owners subject to the restriction and the courts may terminate the restriction under certain conditions.

Express termination

The restrictive covenant may specifically include the time and conditions under which it will no longer be effective. From a practical point of view, however, it is doubtful that a provision of this kind would be found in a restriction against solar energy. Since the motivating rationale behind these restrictions is usually based on aesthetics, the doctrine of "once an eyesore, always an eyesore" will usually make an express termination date unlikely. An alternative provision would stipulate the time for termination with a provision for automatic extension upon landowner approval. In either case, provisions dictating duration are valid and are consistent with the principle affording free use and enjoyment of land.

Modification

A landowner who is subject to restrictive covenants may, by release or upon agreement with the other owners within the subdivision, modify the restrictions. The deed may specify the manner by which the modification will be made, for example, by all or a majority of the affected owners. The developer may also exercise his or her right to modify the restrictions. However, agreement by the landowners to such modification is necessary unless the developer expressly reserved the right to future modifications.

Modification of a restrictive covenant could effectively operate to remove restrictions against the use of solar equipment. For example, where a restrictive covenant prohibits alterations to the street-facing facades of homes in the subdivision, an exception could be provided when the alteration is a solar energy system. The exception could remove all restrictions against the use of solar energy or allow the use of solar energy, subject to approval of an architectural review board. In either case, the restriction would still be effective against all frontal alterations except solar energy systems.

Cancellation

A court of competent jurisdiction may also act to terminate restrictive covenants. In a case in which a homeowner is violating a restriction, other parties to the covenant may sue to recover damages for breach of the covenant, or an injunction may be sought to enforce the restriction. The court may award damages or grant the injunction where it determines the activity is in fact a violation of a valid restriction. The court may, on the other hand, determine the activity is not a violation and deny an award of damages or the injunction. Or, the court may determine on the basis of "changed conditions" that the restriction is no longer valid and thus may order it cancelled. The latter instance is another method of terminating restrictive covenants that prohibit solar and one that has a good chance for success, given current energy policies favoring the use of solar energy.

There are affirmative defenses that can be raised in a situation in which the homeowner is taken to court by his association. Where other homeowners have acted in violation of the same restrictive covenant and the homeowners in the subdivision took no action or approved of the action, the solar owner may allege a waiver or abandonment of the restriction.

For example, in a subdivision where solar collectors are prohibited on the street-facing facade, yet one or more homeowners have installed collectors on this facade without reprisal from other homeowners, the court may deny any request for an injunction against subsequent homeowners installing solar collectors on the street-facing facade. Allowing collectors on the side-yard facing facades of the home that were, nonetheless, visible from the street may not constitute a waiver or abandonment of the restriction. One could maintain an argument for abandonment in that the overall effect is the same, that is, the introduction of a readily visible nonconforming or unaesthetic element into the community. Where work on an installation subject to the restriction has been allowed to progress to the point or where an injunction would present an undue hardship to the defendant, an injunction may only be granted where a nuisance has developed. The scope of the solar project would have an impact on the use of this defense. As in all equitable considerations, the benefits and burdens of competing interests are weighed by the court in arriving at its decision.

Local ordinances

Cities and counties are authorized to adopt ordinances for a variety of purposes. This typically includes the authority to prepare and enforce comprehensive plans, zoning regulations and building codes and to adopt ordinances and resolutions necessary for the exercise of its powers. Despite these broad grants of power for local self-government, the local ordinance is still subject to judicial scrutiny. In addition to the requirement that an act be one within the authority of the local government, it must be reasonable, equal, and impartial in its operation. However, there is a strong presumption of validity of a local ordinance, since local officials are in a better position than the courts are to have knowledge of any local conditions upon which the ordinance is predicated.

In spite of the scope of authority of the local governing body, the principles affecting the validity of its actions still provide several bases to void an anti-solar ordinance. The concepts of reasonableness, consistency and promoting the public interest will be considered. The reasonableness of a local ordinance will be gauged in the context of current events. What was reasonable in an era of inexpensive, plentiful fossil fuel supplies may no longer be considered reasonable given today's energy policies that encourage the use of renewable energy.

While there is authority indicating that land use restrictions may be based on aesthetic considerations alone, the courts have generally held that building regulations based solely on aesthetic considerations cannot be supported under the police power or in the absence of an actual finding of fact that the restrictions bear a reasonable relation to the

public welfare. Given our current energy predicament, it would appear that restrictions imposed on the use of solar energy devices would contravene rather than promote the public interest.

Where a state law prohibits a local government from enacting an ordinance, which directly or effectively prohibits the use of solar energy, the state law will take precedence over the local ordinance. In the case of an ordinance that was in effect prior to the state law, the solar owner may still prevail by citing public policies that favor the use of solar energy.

Analysis of State Solar Access Laws

Thirty-four states (and a handful of municipalities) have some kind of protection for solar easements or solar rights. That leaves 16 states that have no protection. Some of the states lacking solar easements or solar rights laws are surprising, given the other pro-solar/renewable energy policies in the state (Connecticut, Illinois, Pennsylvania, Texas, Vermont, for example). However, even those states that do have solar easements or solar rights laws have enforcement issues that can render the laws ineffective or subject to expensive litigation to enforce. The preliminary review of state solar access and solar rights laws indicates a real need for simplified enforcement of the protection afforded by solar rights laws. In addition, the voluntary nature of solar easement statutes makes them useless to property owners that have neighbors unwilling to provide the solar easement.

There are, however, some notable exceptions to this generalization, and the draft model statute will incorporate features of those states with good law.

Solar easement statutes

Solar easement statutes have very common elements, and virtually all are "voluntary," meaning that a solar owner cannot require that their neighbor agree to a solar easement. The standard elements of a typical solar access law are that it must be in writing, be recorded (as any other real property interest), express the horizontal and vertical angles of the easement, include provisions relating to the grant or termination of the easement, and provide for any compensation arrangements to the grantor for maintaining the easement or to the grantee in the event of interference.

Short of mandating solar easement, one approach used by a state includes a registration process that allows a solar owner to register their solar system with the local governing body—essentially putting their neighbors on notice that the solar system is in place. In that event, a solar owner can, in essence, impose a solar easement on the neighbor. This is a very unique and potentially effective solar access tool. There are also states that direct the local governing body to require a solar access element in subdivision or development plans submitted for their review and approval. While this is noteworthy, it will only protect solar access in new construction.

Solar rights

There are essentially two models that have perpetuated over the last two-plus decades that attempt to protect the right of homeowners to install solar energy systems. The first model addresses local government ordinances; the second model addresses private land use restrictions, such as covenants, conditions, and restrictions in deeds, as well as declarations in condominiums documents. Some states address both.

The typical language of a statute that protects solar rights at the state or local government level will contain language such as, "The adoption of an ordinance by a governing body which prohibits or has the effect of prohibiting the installation of solar collectors is expressly prohibited." The typical language of a statute that protects solar

rights in the context of private land use restrictions is, "Any covenant, restriction, or condition contained in any deed, contract, security agreement, or other instrument affecting the transfer or sale of or any interest in real property which effectively prohibits the installation or use of a solar energy device is void and unenforceable." Some states distinguish their laws from others by defining solar energy device, providing or prohibiting retroactive effect, defining "effectively prohibiting" (usually by assigning a cost of compliance with a requirement). For the most part, the laws apply strictly to residential buildings, including condominiums.

Typical cases

Previous work has identified some of the shortcomings of traditional solar access laws (Starrs, Nelson, & Zalcman, 1999). The lack of awareness and understanding of solar rights statutes is one of the biggest obstacles to enforcement. The lack of awareness by homeowner associations and architectural review boards can lead to delays in processing applications and lawsuits that are expensive to defend and cost all parties, regardless of who prevails. Because, when a solar rights law awards the court costs and attorney fees to the prevailing party, and the homeowner is the prevailing party, they still end up paying since all homeowners in the community bear the common expenses, such as attorney fees. The lack of understanding of solar rights laws by homeowners and solar contractors can lead to missteps in the approval process. Most solar rights laws are not absolute; they still require that the homeowner apply to the architectural review board for approval, and the board has a degree of discretion in the approval process. Many homeowners and contractors believe that approval is not required and proceed with the installation without prior approval. This can lead to legal recourse by the association that has no bearing on the solar rights laws but rather pertain to the failure to follow association rules.

The following cases are examples of real events and represent the range of scenarios that occur on a daily basis.

Case 1: A homeowner purchases a solar energy system. The contractor arrives on site for installation. As neighbors notice the activity, they confront the homeowner and inquire as to the architectural review board's approval. The neighbor cites the solar rights law and says permission is not necessary. The association advises the homeowner to cease and desist work and to restore the premises to its original condition and levies a fine for every day they are in violation.

Case 2: A homeowner purchases a solar energy system. Approval from the architectural review board (ARB) is pending. The contractor applies for a permit from the local building agency, which refuses to issue the permit until a copy of the ARB approval is received. Alternately, the ARB requires a copy of the permit before approval is granted. The building permit process is so cumbersome, the contractor does not pull a permit, and ARB approval is denied.

Case 3: A homeowner considers purchase of a solar energy system. Deed restrictions require that the system not be visible from the street. The homeowner has a corner lot, and the only area not visible from the street faces north. The contractor devises a reverse mount for the collectors and runs afoul of local wind and structural codes.

Case 4: A homeowner/condominium association owns the exterior of the residence including the roof (common property). The request to install the solar energy system is denied, as they fear the roof warranty being voided, and question the liability for any damage to common property.

Case 5: A homeowner installs a solar energy system. A neighbor to the south has several very mature trees that are creeping into the solar window. The homeowner asks the neighbor to trim the trees, but the neighbor refuses, arguing that the shade of the trees reduces their air-conditioning load.

Case 6: A developer builds all homes in the community with a solar water heater and photovoltaic system. The solar window requires that a tree protected by the local landscape ordinance be removed. The developer is required to purchase and replant $20,000 trees to compensate for the removal of the protected tree.

These are just a handful of the cases, all of which occurred in states with solar rights and solar access laws. The bottom line is that the law failed to protect the solar owner or cost the solar owner more than the value of the solar energy system to secure that protection.

Exemplary Solar Access Laws

In the effort to develop a model solar access statute, we first reviewed the current law on point and critiqued the relative effectiveness of those laws, given the outcomes that were available, in terms of lawsuits, media coverage, and other resources that reported pertinent disputes. Our review of the text of solar access laws in the United States reveals some excellent provisions that can be used to draft a model solar access statute. Our goal was to be able to resolve the typical case via the provisions of the model statute. In addition, the solar industry has developed model solar installation guidelines that can be adopted by homeowner associations.

City of Gainesville, Florida

- Allows the removal of regulated (i.e., protected) trees, where they will prevent the installation of solar energy equipment (Statutory Reference 1).

State of Hawaii

- Provides a very comprehensive list of instruments that are affected (covenant, declaration, bylaws, restriction, deed, lease, term, provision, condition, codicil, contract, or similar binding agreement, how ever worded) declaring that no person shall be prevented by anyone from installing a solar energy device on any single-family residential dwelling or townhouse that the person owns, making any provision in any lease, instrument, or contract contrary to the intent of the law void and unenforceable.
- Also provides that every private entity (meaning community association) adopt rules for the placement of solar collectors: "The rules shall facilitate the placement of solar energy devices and shall not unduly or unreasonably restrict that placement so as to render the device more than twenty-five percent less efficient or to increase the cost of the device by more than fifteen percent."
- Spells out the relative risks and responsibilities, when installing solar energy equipment on common property (Statutory Reference 2).

State of Massachusetts

- Provides for, among other things, a solar easement as well as a solar access permit.
- Voids restrictions against use of solar energy.
- Provides for solar access guidelines in subdivision regulation.
- Also provides for solar access in zoning ordinances, including the regulation of planting and trimming of vegetation on public property to protect solar access on public and private solar energy systems.

- Solar access permit language is novel and provides an excellent model:

  Zoning ordinances or bylaws may also provide for special permits to protect access to direct sunlight for solar energy systems. Such ordinances or bylaws may provide that such solar access permits would create an easement to sunlight over neighboring property. Such ordinances or bylaws may also specify what constitutes an impermissible interference with the right to direct sunlight granted by a solar access permit and how to regulate growing vegetation that may interfere with such right. Such ordinances or bylaws may further provide standards for the issuance of solar access permits, balancing the need of solar energy systems for direct sunlight with the right of neighboring property owners to the reasonable use of their property within other zoning restrictions. Such ordinances or bylaws may also provide a process for issuance of solar access permits including, but not limited to, notification of affected neighboring property owners, opportunity for a hearing, appeal process and recordation of such permits on burdened and benefited property deeds. Such ordinances or bylaws may further provide for establishment of a solar map identifying all local properties burdened or benefited by solar access permits. Such ordinances or bylaws may also require the examination of such solar maps by the appropriate official prior to the issuance of a building permit (Statutory Reference 3).

State of New Jersey

- While this law's prohibition against deed restrictions that prohibit solar energy is fairly typical, it provides for enforcement of the law by the state's Department of Community Affairs, which hopes to avoid the need for expensive litigation (Statutory Reference 4).

State of New Mexico

- Provides that a homeowner can record ownership of a solar energy system and allows the owner to establish a solar easement: "A solar right may be claimed by an owner of real property upon which a solar collector…has been placed. Once vested, the right shall be enforceable against any person who constructs or plans to construct any structure, in violation of the terms of the Solar Rights Act…or the Solar Recordation Act… A solar right shall be considered an easement appurtenant, and a suit to enforce a solar right may be brought at law or in equity" (Statutory Reference 5).

City of Ashland, Oregon

- Establishes a procedure for a obtaining a solar access permit to protect a solar energy system from vegetation that would shade the collector.
- Provides for recording the easement.
- This detailed ordinance provides a level of protection that a voluntary solar easement does not. The procedures for obtaining the permit are comprehensive and protect the interests of all parties involved (Statutory Reference 6).

Virgin Islands

- Provides that deed restrictions (and other instruments) that prohibit the use of solar and wind energy are void and unenforceable.
- Also provides for a greater height restriction for solar and wind energy devices and provides for the dedication of solar easements as a condition of subdivision approval (Statutory Reference 7).

State of Wisconsin

- Provides local governments with the authority to enact an ordinance to require the trimming of vegetation that blocks solar energy equipment.
- Also, provides that restriction against the use of solar or wind energy are void (Statutory Reference 8).

Recommendations

Given the fact that many of the current laws that purport to protect solar access are ineffective or too expensive to enforce, every state should examine its practices and consider amending them to conform to the model statute. At the state level, the adoption of the model statute that addresses state and local practices on use of solar energy equipment is recommended. The model statute should include prescriptive measures—such as community design, solar easements, as well as prohibitive measures, such as measures restricting the use of solar energy.

At the local level, it is recommended that the focus be on implementation and enforcement of state law, requirement that site-plan review and approval include an element to address the current and future use of solar energy (such as solar easements, landscaping, building height restriction, and orientation).

The key to the usefulness of a solar access law is enforcement. It is imperative that a specific entity be charged with oversight of the statute. These responsibilities must include responding to consumer and community association inquiries, conflict resolution, and the authority to impose penalties for violation of the statute.

Through strategic partnerships with the League of Cities, Association of Counties, and the Community Association Institute, education and awareness of solar access laws can proactively avoid disputes among neighbors. It is further recommended that partnering with these entities be explored to expand the outreach of this effort.

Components of Solar Access Legislation

Elements of a Solar Rights and Access Law

1. Preamble
    a. Public Purpose (needed to assure constitutionality)
    b. Policy Statement in Support of Solar Energy (needed to allow for retroactive effect and overcome constitutional challenge)
    c. Legislative Intent (for example
        i. Energy security
        ii. Cost of energy
        iii. Green House Gas reduction strategy
        iv. Economic development
        v. Fossil fuel offset
        vi. Renewable Portfolio Standard
        vii. Other
2. Definitions
    a. Solar Energy Device (active and passive)
    b. Other renewable measures (wind, geothermal, etc)
    c. Buildings included (residential, commercial, multi-family, condominium)
    d. Other

3. Application
    a. CCRs
    b. Solar contract
    c. Condominium declarations
    d. Ordinances
    e. Enforcement
        i. Litigation
        ii. Prevailing party legal fee award
        iii. Penalties
        iv. Code enforcement

4. Where the law should be codified
    a. Constitutional amendment
    b. Municipal law section
    c. Building code section
    d. Condominium regulation section
    e. Homeowner association section

MODEL STATUTE/ORDINANCE TO ENCOURAGE ACCESS TO SOLAR ENERGY

STATE/CITY/COUNTY _____

CHAPTER/SECTION NO. _____

A LAW PROVIDING FOR SOLAR EASEMENTS; INVALIDATING PUBLIC AND PRIVATE RESTRICTIONS RESTRICTING THE USE OF SOLAR ENERGY SYTEMS; ESTABLISHING GUIDELINES FOR THE INSTALLATION OF SOLAR ENERGY SYSTEMS, INCLUDING STANDARDS AND PERMIT REQUIREMENTS; PROVIDING FOR CERTIFICATION OF INSTALLERS OF SOLAR ENERGY SYSTEMS; PROVIDING FOR ENFORCEMENT AND PENALTIES; SUPERSEDING ALL LAWS IN CONFLICT OR INCONSISTENT HEREWITH; PROVIDING AN EFFECTIVE DATE.

WHEREAS, the State/City/County of _____ wishes to advance the use of solar energy by all of its citizens, businesses and industries; and,

WHEREAS, the State/City/County of _____has determined that public and private land use and property restrictions can impair the ability of our citizens, businesses and industries to install said systems; and,

WHEREAS, properly designed land use standards can prepare communities for greater access to solar energy; and,

WHEREAS, the installation of solar energy systems according to established guidelines by properly trained and certified personnel is essential to the safe and efficient operation of said systems;

[ADD OTHER STATE SPECIFIC POLICIES THAT MIGHT BE CITED HERE]

NOW, THEREFORE, it is in the interest of the health, welfare and safety of the people of _____ to provide the infrastructure to assure the effective deployment of solar technology.

NOW, BE ENACTED BY THE STATE OF _____ OR
NOW, THEREFORE, BE IT ORDAINED BY THE BOARD OF CITY/COUNTY COMMISSIONERS OF _____ _____, that:
(City/County) (State)

This Section Is Intended to be Interactive among Stakeholders to Explore the Options and Get Feedback from States/Cities with Best Practices as Identified in the Exemplary Law Section.

Section 1. Definitions

"Solar Energy Device" (active and passive): (Florida model) Solar energy device means the equipment and requisite hardware that provide and are used for collecting, transferring, converting, storing, or using incident solar energy for water heating, space heating, cooling, generating electricity, or other applications that would otherwise require the use of a conventional source of energy such as petroleum products, natural gas, manufactured gas, or electricity produced from a nonrenewable resource.

"Other renewable measures" - [Each jurisdiction needs to evaluate their renewable energy resources to determine which technologies to include in the statute.]

Section 2. Solar Easements

(Massachusetts model, others to consider: New Jersey and New Mexico, City of Ashland)

A. An easement of direct sunlight may be acquired over the land of another by express grant or covenant, or by a solar access permit as set forth in section 2. Any instrument creating a solar easement may include, but the contents are not limited to, all of the following:

(1) A description of the dimensions of the easement expressed in measurable terms, such as vertical or horizontal angles measured in degrees, or the hours of the day on specified dates during which direct sunlight to a specified surface of a solar collector, device, or structural design feature may not be obstructed, or a combination of these descriptions.

(2) The restrictions placed upon vegetation, structures, and other objects which would impair or obstruct the passage of sunlight through the easement.

(3) The amount, if any, of permissible obstruction of the passage of sunlight through the easement, expressed in measurable terms, such as a specific percentage of sunlight that may be obstructed.

(4) The provisions for trimming vegetation that would impermissibly obstruct the passage of sunlight through the easement including any compensation for trimming expenses.

(5) Any provisions for compensation of the owner of property benefiting from the easement in the event of impermissible obstruction of the easement.

(6) The terms or conditions, if any, under which the easement may be revised or terminated.

Any instrument creating a solar easement shall be recorded in the registry of deeds in the county or district or, in the case of registered land, in the registry district of the land court in which the land affected is situated.

B. Zoning ordinances or community association bylaws may provide for special permits to protect access to direct sunlight for solar energy systems. Such ordinances or bylaws may provide that such solar access permits create an easement to sunlight over neighboring property. Such ordinances or bylaws may also specify what constitutes an impermissible interference with the right to direct sunlight granted by a solar access permit and how to regulate growing vegetation that may interfere with such right. Such ordinances or bylaws may further provide standards for the issuance of solar access permits balancing the need of solar energy systems for direct sunlight with the right of neighboring property owners to the reasonable use of their property within other zoning restrictions. Such ordinances or bylaws may also provide a process for issuance of solar access permits including, but not limited to, notification of affected neighboring property owners, opportunity for a hearing, appeal process and recordation of such permits on burdened and benefited property deeds. Such ordinances or bylaws may further provide for establishment of a solar map identifying all local properties burdened or benefited by solar access permits. Such ordinances or bylaws may also require the examination of such solar maps by the appropriate official prior to the issuance of a building permit.

Section 3. Solar Rights

(Massachusetts model, others to consider: Hawaii and Wisconsin)

Solar energy systems; installation or use; restrictive provisions
Any provision in an instrument relative to the ownership or use of real property which purports to forbid or unreasonably restrict the installation or use of a solar energy system or the building of structures that facilitate the collection of solar energy shall be void.
A community association shall not adopt and shall not enforce any rule related to the installation or maintenance of solar collectors, if compliance with a rule or rules would increase the solar collectors' installation or maintenance costs by an amount which is estimated to be greater than 10 percent of the total cost of the initial installation of the solar collectors, including the costs of labor and equipment. A community association shall not adopt and shall not enforce any rule related to the installation or maintenance of solar collectors, if compliance with such rules inhibits the solar collectors from functioning at their intended maximum efficiency. The [Agency] shall enforce the provisions of this law in accordance with the authority granted under [section x].

Section 4. Local Ordinances

(Massachusetts model, Florida provision)

A. Zoning ordinances or bylaws adopted or amended pursuant to section five of this chapter may encourage the use of solar energy systems and protect solar access by regulation of the orientation of streets, lots and buildings, maximum building height limits, minimum building set back requirements, limitations on the type, height and placement of vegetation and other provisions. Zoning ordinances or bylaws may also establish buffer zones and additional districts that protect solar access which overlap existing zoning districts. Zoning ordinances or bylaws may further regulate the planting and trimming of vegetation on public property to protect the solar access of private and public solar energy systems and buildings. Solar energy systems may be exempted from set back, building height, and roof and lot coverage restrictions.

B. Notwithstanding any provision of general or special law, the adoption of an ordinance by a city or county which prohibits or has the effect of prohibiting the installation of solar energy systems [or other device based on renewable resources] is expressly prohibited.

References

Boyd v. McDonald. 408 P.2d 717. (1965).

Caton, D., & Kettles, CM (1980). Solar Law, Vol 4, No. 77, Florida Municipal Record.

Fontainebleau Hotel Corp. v. Forty-Five Twenty-Five, Inc., 114 So.2d 357 (1959), cert. denied 117 So.2d 842.

Kramer, SE (1978). Solar Law. Colorado Springs, CO, Shepards, Inc.

United States v. Causby, 328 U.S. 256, 66 S.1. 1062 (1946).

Sacramento and San Joaquin Drainage District v. Reed, 215 Cal. App. 2d 60 (1963)

T. Starrs, L. Nelson, and F. Zalcman, (1999). *Bringing Solar Energy to the Planned Community: A Handbook on Rooftop Solar Systems and Private Land Use Restrictions* (Contract Number: DE – FG01 – 99EE10704), U.S. Department of Energy, Office of Scientific and Technical Information: Oak Ridge, TN.

UK Statute Law Database, Office of Public Sector Information, United Kingdom.

APPENDIX

Statutory References

1. CITY OF GAINESVILLE, FLORIDA

§30-254. Permits for tree removal.

(e) Permit approval criteria. Removal or relocation of regulated trees shall be approved by the city manager or designee upon a finding that the trees pose a safety hazard; have been weakened by disease, age, storm, fire or other injury; or prevent the reasonable development of the site, including the installation of solar energy equipment. Regulated trees shall not be removed, damaged or relocated for the purpose of locating utility lines and connections unless no reasonably practical alternative as determined by the city manager or designee is available.

2. STATE OF HAWAII

§196-7 Placement of solar energy devices.

(a) Notwithstanding any law to the contrary, no person shall be prevented by any covenant, declaration, bylaws, restriction, deed, lease, term, provision, condition, codicil, contract, or similar binding agreement, however worded, from installing a solar energy device on any single-family residential dwelling or townhouse that the person owns. Any provision in any lease, instrument, or contract contrary to the intent of this section shall be void and unenforceable.

(b) Every private entity shall adopt rules by December 31, 2006, that provide for the placement of solar energy devices. The rules shall facilitate the placement of solar energy devices and shall not unduly or unreasonably restrict that placement so as to render the device more than twenty-five per cent less efficient or to increase the cost of the device by more than fifteen per cent. No private entity shall assess or charge any homeowner any fees for the placement of any solar energy device.

(c) Any person may place a solar energy device on any single-family residential dwelling or townhouse unit owned by that person, provided that:

(1) The device is in compliance with the rules and specifications adopted pursuant to subsection (b);

(2) The device is registered with the private entity of record within thirty days of installation; and

(3) If the device is placed on a common element or limited common element as defined by a project's declaration, the homeowner shall first obtain the consent of the private entity; provided further that such consent shall be given if the homeowner agrees in writing to:

(A) Comply with the private entity's design specification for the installation of the device;

(B) Engage a duly licensed contractor to install the device; and

(C) Within fourteen days of approval of the solar device by the private entity, provide a certificate of insurance naming the private entity as an additional insured on the homeowner's insurance policy.

(d) If a solar energy device is placed on a common element or limited common element:

(1) The owner and each successive owner of the single-family residential dwelling or townhouse unit on which the device is placed shall be responsible for any costs for damages to the device, the common elements, limited common elements, and any adjacent units, arising or resulting from the installation, maintenance, repair, removal, or

replacement of the device. The repair, maintenance, removal, and replacement responsibilities shall be assumed by each successive owner until the solar energy device has been removed from the common elements or limited common elements. The owner and each successive owner shall at all times have and maintain a policy of insurance covering the obligations of the owner under this paragraph and shall name the private entity as an additional insured under said policy; and

(2) The owner and any successive owner of the single-family residential dwelling or townhouse unit on which the device is placed shall be responsible for removing the solar energy device if reasonably necessary or convenient for the repair, maintenance, or replacement of the common elements or limited common elements.

(e) If a material or labor roof warranty exists at the time a solar energy device is installed on a roof that is a common element or limited common element, the homeowner shall obtain confirmation in writing from the company that issued the warranty that the installation of the solar energy device will not void the roof warranty. The homeowner shall provide the private entity with a copy of the confirmation.

(f) For the purposes of this section:
"Private entity" means any association of homeowners, community association, condominium association, cooperative, or any other non-governmental entity with covenants, bylaws, and administrative provisions with which the homeowner's compliance is required.

"Solar energy device" means any identifiable facility, equipment, apparatus, or the like, including a photovoltaic cell application, that is applicable to a single-family residential dwelling or townhouse and makes use of solar energy for heating, cooling, or reducing the use of other types of energy dependent upon fossil fuel for generation; provided that "solar energy device" shall not include skylights or windows. [L 1992, c 268, §1; am L 2005, c 157, §2]

3. STATE OF MASSACHUSETTS

CHAPTER 187. EASEMENTS
Chapter 187: Section 1A. Solar easements

Section 1A. An easement of direct sunlight may be acquired over the land of another by express grant or covenant, or by a solar access permit as set forth in section 9B of chapter 40A.

Any instrument creating a solar easement may include, but the contents are not limited to, all of the following:

(1) A description of the dimensions of the easement expressed in measurable terms, such as vertical or horizontal angles measured in degrees, or the hours of the day on specified dates during which direct sunlight to a specified surface of a solar collector, device, or structural design feature may not be obstructed, or a combination of these descriptions.

(2) The restrictions placed upon vegetation, structures, and other objects which would impair or obstruct the passage of sunlight through the easement.

(3) The amount, if any, of permissible obstruction of the passage of sunlight through the easement, expressed in measurable terms, such as a specific percentage of sunlight that may be obstructed.

(4) The provisions for trimming vegetation that would impermissibly obstruct the passage of sunlight through the easement including any compensation for trimming expenses.

(5) Any provisions for compensation of the owner of property benefiting from the easement in the event of impermissible obstruction of the easement.

(6) The terms or conditions, if any, under which the easement may be revised or terminated.

Any instrument creating a solar easement shall be recorded in the registry of deeds in the county or district or, in the case of registered land, in the registry district of the land court in which the land affected is situated.

Chapter 184: Section 23C. Solar energy systems; installation or use; restrictive provisions

Section 23C. Any provision in an instrument relative to the ownership or use of real property which purports to forbid or unreasonably restrict the installation or use of a solar energy system as defined in section one A of chapter forty A or the building of structures that facilitate the collection of solar energy shall be void.

Chapter 40A: Section 1A. Definitions

Section 1A. As used in this chapter the following words shall have the following meanings:

Permit granting authority: the board of appeals or zoning administrator.

Solar access: the access of a solar energy system to direct sunlight.

Solar energy system: a device or structural design feature, a substantial purpose of which is to provide daylight for interior lighting or provide for the collection, storage and distribution of solar energy for space heating or cooling, electricity generating, or water heating.

Special permit granting authority: the board of selectmen, city council, board of appeals, planning board, or zoning administrators as designated by zoning ordinance or bylaw for the issuance of special permits.

Zoning: ordinances and bylaws adopted by cities and towns to regulate the use of land, buildings and structures to the full extent of the independent constitutional powers of cities and towns to protect the health, safety and general welfare of their present and future inhabitants.

Zoning administrator: a person designated by the board of appeals pursuant to section 13 to assume certain duties of said board.

Chapter 40A, Section 9B: Solar access

Section 9B. Zoning ordinances or bylaws adopted or amended pursuant to section five of this chapter may encourage the use of solar energy systems and protect solar access by regulation of the orientation of streets, lots and buildings, maximum building height limits, minimum building set back requirements, limitations on the type, height and placement of vegetation and other provisions. Zoning ordinances or bylaws may also establish buffer zones and additional districts that protect solar access which overlap existing zoning districts. Zoning ordinances or bylaws may further regulate the planting and trimming of vegetation on public property to protect the solar access of private and public solar energy systems and buildings. Solar energy systems may be exempted from set back, building height, and roof and lot coverage restrictions.

Zoning ordinances or bylaws may also provide for special permits to protect access to direct sunlight for solar energy systems. Such ordinances or bylaws may provide that such solar access permits would create an easement to sunlight over neighboring property. Such ordinances or bylaws may also specify what constitutes an impermissible interference with the right to direct sunlight granted by a solar access permit and how to regulate growing vegetation that may interfere with such right. Such ordinances or bylaws may further provide standards for the issuance of solar access permits balancing the need of solar energy systems for direct sunlight with the right of neighboring property owners to the reasonable use of their property within other zoning restrictions. Such ordinances or bylaws may also provide a process for issuance of solar access permits including, but not limited to, notification of affected neighboring property owners, opportunity for a hearing, appeal process and recordation of such permits on burdened and benefited property deeds. Such ordinances or bylaws may further provide for establishment of a solar map identifying all local properties burdened or benefited by solar access permits. Such ordinances or bylaws may also require the examination of such solar maps by the appropriate official prior to the issuance of a building permit.

4. STATE OF NEW JERSEY

§ 45:22A-48.2. Solar collectors on certain roofs, homeowners' association authority limited

a. An association formed for the management of commonly-owned elements and facilities, regardless of whether organized pursuant to section 1 of P.L.1993, c.30 (C.45:22A-43), shall not adopt or enforce a restriction, covenant, bylaw, rule or regulation prohibiting the installation of solar collectors on certain roofs of dwelling units, as follows:

> A roof of a single family dwelling unit which is solely owned by an individual or individuals, and which is not designated as a common element or common property in the governing documents of an association; and
>
> A roof of a townhouse dwelling unit, which for the purposes of this subsection means any single-family dwelling unit constructed with attached walls to another such unit on at least one side, which unit extends from the foundation to the roof, and has at least two sides which are unattached to any other building, and the repair of the roof for the townhouse dwelling unit is designated as the responsibility of the owner and not the association in the governing documents.

b. An association may adopt rules to regulate the installation and maintenance of solar collectors on those roofs as specified in subsection a. of this section, in accordance with subsection c. of this section, and as follows:

(1) The qualifications, certification and insurance requirements of personnel or contractors who may install the solar collectors;

(2) The location where solar collectors may be placed on roofs;

(3) The concealment of solar collectors' supportive structures, fixtures and piping;

(4) The color harmonization of solar collectors with the colors of structures or landscaping in the development; and

(5) The aggregate size or coverage or total number of solar collectors, provided that the provisions of paragraph (2) of subsection c. below are met.

c. (1) An association shall not adopt and shall not enforce any rule related to the installation or maintenance of solar collectors, if compliance with a rule or rules would increase the solar collectors' installation or maintenance costs by an amount which is estimated to be greater than 10 percent of the total cost of the initial installation of the solar collectors, including the costs of labor and equipment.
(2) An association shall not adopt and shall not enforce any rule related to the installation or maintenance of solar collectors, if compliance with such rules inhibits the solar collectors from functioning at their intended maximum efficiency.

d. The Commissioner of Community Affairs shall enforce the provisions of P.L.2007, c.153 (C.45:22A-48.2) in accordance with the authority granted under section 18 of P.L.1977, c. 419 (C.45:22A-38).

e. The provisions of P.L.2007, c.153 (C.45:22A-48.2) shall not apply to associations that are under the control of the developer as provided under section 5 of P.L.1993, c.30 (C.45:22A-47).

5. STATE OF NEW MEXICO

[Statute modified by editor to clarify and update]

Solar Recordation Act – Sections 47-3-6 to-12 NMSA 1978 47-3-6. Short title.

This act [47-3-6 to 47-3-12 NMSA 1978] may be cited as the "Solar Recordation Act."

47-3-7. Legislative findings and declaration

The legislature finds that in view of the present energy crisis, all renewable energy sources must be encouraged for the benefit of the state as a whole. The legislature further finds that solar energy is a viable energy source in New Mexico, and as such, its development should be encouraged. Since solar energy may be used in small-scale installations and one of the ways to accomplish such encouragement is by protection of rights necessary for small-scale installations, the legislature declares such protection to be the purpose of the Solar Recordation Act [47-3-6 to 47-3-12 NMSA 1978] and necessary to the public interest.

47-3-8. Method of claiming; effect; limitations

A solar right may be claimed by an owner of real property upon which a solar collector, as defined in Subsection A of Section 47-3-3 NMSA 1978, has been placed. Once vested, the right shall be enforceable against any person who constructs or plans to construct any structure, in violation of the terms of the Solar Rights Act [47-3-1 to 47-3-5 NMSA 1978] or the Solar Recordation Act [47-3-6 to 47-3-12 NMSA 1978]. A solar right shall be considered an easement appurtenant, and a suit to enforce a solar right may be brought at law or in equity. The solar right shall be subject to the provisions of the Solar Recordation Act and the Solar Rights Act.

47-3-9. Recordation; effect of failure to record; contest.

A. Any person claiming a solar right shall record that right by filing a declaration in substantially the following form with the county clerk of each county in which is located any portion of the properties burdened by a solar right or any portion of the properties on which a solar right is claimed.

SOLAR RIGHT DECLARATION

[Name of person] _____owner of the real property described below, claims a solar right in favor of the following described real estate in _____county, New Mexico:

(Description either by metes and bounds, if in a platted subdivision, by lot and block subdivision name, by middle Rio Grande conservancy district tract number or other adequate legal description.)

The following named persons have each received notification by certified mail evidenced by a return receipt signed by the named person, or if the address of any person was not known and could not be ascertained by reasonable diligence, or if a return receipt signed by the named person could not be obtained, then notification to that person shall be made by publication of a copy of this declaration, with the intended date of filing, at least once a week for two consecutive weeks in a newspaper of general circulation in the county in which the property for which the solar right is being claimed is located, the last publication of which was no less than ten days prior to the filing of this declaration: (A listing of the names of the holders as shown in the records of the county clerk of any interest in property burdened by a claimed solar right, including owners, mortgagors, mortgagees, lessors, lessees, contract purchasers and contract owners or sellers, and a description, either by metes and bounds if in a platted subdivision, by lot and block and subdivision name, by middle Rio Grande conservancy district tract number or other adequate legal description, of that burdened property.)

The claimant has placed improvements on the land in the form of a solar collector, as shown by the attached survey or plot plan setting forth distances from lot lines and height from ground level of all solar collectors entitled to be recorded under the provisions of the Solar Recordation Act … and setting forth the maximum height of a theoretical fence located at the property lines of the property on which the solar collector is located which will not interfere with the solar easement.

Notice is hereby given that by virtue of the Solar Recordation Act, the holders of any interest in property described above as having been mailed notice must record a declaration, with the county clerk in each county in which solar right recordation has been filed, contesting the claimed solar right within sixty days, or the solar right shall be fully vested. Witness [Name of person]set his hand and seal this _____ day of _____, [year][Document must be notarized].

B. Any person desiring to claim a solar right must record that right and give notice to affected property owners as provided in the Solar Recordation Act as a necessary condition precedent to enforcing a solar right. Failure to so record and give notice shall constitute a jurisdictional defect and deprive any court of subject matter jurisdiction to enforce the solar right. However, nothing in this subsection shall apply to any solar right, lease, easement or contract right which has vested prior to the effective date of this subsection.

C. Any person who receives notice of the recordation may, within sixty days after receiving notice, file a declaration contesting the right, in the same manner and at the same place as the recordation was filed. If a declaration is filed contesting the claimed solar right, then the solar right shall not be enforceable against the property covered by the declaration unless agreed to by contract or ordered by a court of competent jurisdiction, and any claim of a solar right shall expire one year from the date of declaration unless the parties agree by contract to settle the solar rights dispute or unless court action has commenced by that date to establish the claim of the solar right.

47-3-10: transfer

Unless the document of conveyance otherwise specifies, upon the transfer of any realty on which a solar right exists or upon the transfer of any realty benefited by a filed declaration contesting a solar right, that solar right or declaration contesting the solar

right shall be transferred with the realty and shall be enforceable by the vendee in the same manner and to the same extent to which it was enforceable by the vendor. A solar right is appurtenant to the real property upon which the solar collector is situated. Nothing in this section shall be construed to prevent a person from agreeing to relinquish a solar right or a potential solar right. Nothing in this section shall affect any transfer of solar rights made prior to the effective date of the Solar Recordation Act … pursuant to Paragraph (3) of Subsection B of Section 47-3-4 NMSA 1978 or any local solar rights ordinance.

47-3-11: local authority

A. Notwithstanding any other provisions of the Solar Recordation Act or the Solar Rights Act, the governing body of a county or municipality may by ordinance regulate in whole or in part the claiming of solar rights in accordance with its powers to regulate zoning, planning and platting, and subdivisions; except that any solar right claimed pursuant to such local ordinance shall vest with respect to any property benefited or burdened by the solar right only after recordation as provided in Section 4 [47-3-9 NMSA 1978] of the Solar Recordation Act. Such local regulation shall not affect any solar right vested before the effective date of such ordinance, nor shall the local regulation affect any solar rights transfer, which vested prior to the effective date of such ordinance. In the absence of the local regulation of solar rights, the following principles shall apply in addition to those set forth in the Solar Rights Act. If the property burdened by a solar right has or could have improvements constructed to a maximum height of twenty-four feet, then the solar right shall be limited, as to that burdened property, to protecting an unobstructed line-of-sight path from the solar collector to the sun only as to obstructions located on the burdened property, which cast a shadow greater than the shadow cast by a hypothetical fence ten feet in height located on the property line of the property on which the solar collector is located. If the property burdened by a solar right has or could have improvements constructed in excess of twenty-four feet in height, but no greater than thirty-six feet, then the solar right shall be limited, as to that burdened property, to protecting an unobstructed line-of-sight path from the solar collector to the sun only as to obstructions located on the burdened property, which cast a shadow greater than the shadow cast by a hypothetical fence fifteen feet in height located on the property line of the property on which the solar collector is located. No solar right shall be obtained against property, which has or could have improvements constructed in excess of thirty-six feet in height unless so provided in a local ordinance or agreed to by contract. Unless otherwise provided by contract or local ordinance, a person may allow vegetation to grow or construct or plan to construct any improvement which obstructs the protected solar right so long as such obstruction does not block more than ten percent of the collectible solar energy between the hours of 9:00 a.m. and 3:00 p.m. Unless otherwise provided by contract or local ordinance, solar rights shall be protected between 9:00 a.m. and 3:00 p.m.

B. Nothing in the Solar Recordation Act shall be construed to limit any county or municipal ordinances concerning solar rights in effect prior to the effective date of this section.

47-3-12: indexing

A declaration filed pursuant to Section 4 [47-3-9 NMSA 1978] of the Solar Recordation Act shall be indexed by the county clerk in the grantees index under the names of the persons receiving notice in the declaration and in the grantors index under the name of the person filing the declaration.

6. CITY OF ASHLAND, OREGON

18.70 Solar Access

18.70.010 Purpose and Intent

The purpose of the Solar Access Chapter is to provide protection of a reasonable amount of sunlight from shade from structures and vegetation whenever feasible to all parcels

in the City to preserve the economic value of solar radiation falling on structures, investments in solar energy systems, and the options for future uses of solar energy.
18.70.020 Definitions

A. *Exempt Vegetation*: All vegetation over fifteen (15) feet in height at the time a solar access permit is applied for.

B. *Highest Shade Producing Point*: The point of a structure which casts the longest shadow beyond the northern property boundary at noon on December 21st.

C. *Natural Grade*: The elevation of the natural ground surface in its natural state, before man-made alterations. The natural ground surface is the ground surface in its original state, before any grading, excavation, or filling.

D. *Northern Lot Line*: Any lot line or lines less than forty-five (45) degrees southeast or southwest of a line drawn east-west and intersecting the northernmost point of the lot. If the northern lot line adjoins any unbuildable area (e.g., street, alley, public right-of-way, parking lot, or common area) other than a required yard area, the northern lot line shall be that portion of the northerly edge of the unbuildable area which is due north from the actual northern edge of the applicant's property.

E. *North-South Lot Dimension*: The average distance in feet between lines from the corners of the northern lot line south to a line drawn east-west and intersecting the southernmost point of the lot.

F. *Solar Energy System*: Any device or combination of devices or elements which rely upon direct sunlight as an energy source, including but not limited to any substance or device which collects sunlight for use in the heating or cooling of a structure or building, the heating or pumping of water, or the generation of electricity. A solar energy system may be used for purposes in addition to the collection of solar energy. These uses include, but are not limited to, serving as a structural member of part of the roof of a building or structure and serving as a window or wall.

G. *Solar Envelope*: A three dimensional surface which covers a lot and shows, at any point, the maximum height of a permitted structure which protects the solar access of the parcel(s) to the north.

H. *Solar Heating Hours*: The hours and dates during which solar access is protected by a solar access permit, not to exceed those hours and dates when the sun is lower than twenty-four (24) degrees altitude and greater than seventy (70) degrees east and west of true south.

I. *Solar Access Permit Height Limitations*: The height limitations on affected properties required by the provisions of a Solar Access Permit displayed as a series of five (5) foot contour lines which begin at the bottom edge of the solar energy system protected by the permit, rise at an angle to the south not less than twenty-four (24) degrees from the horizon, and extend at an angle not greater than seventy (70) degrees to the east and west of true south and run parallel to the solar energy system.

J. *Solar Setback*: The minimum distance that a structure, or any part thereof, can be located from a property boundary.

K. *Slope*:A vertical change in elevation divided by the horizontal distance of the vertical change. Slope is measured along lines extending one hundred fifty (150) feet north from

the end points of a line drawn parallel to the northern lot line through the midpoint of the north-south lot dimension. North facing slopes will have negative (-) values and south facing slopes will have positive (+) values.

L. *Sun chart*: Photographs or drawings, taken in accordance with the guidelines of the Staff Advisor, which plot the position of the sun during solar heating hours. The sun chart shall contain at a minimum the southern skyline as seen through a grid which plots solar altitude for a forty-two (42) degree northern latitude in ten (10) degree increments and solar azimuth measured from true south in fifteen (15) degree increments. If the solar energy system is less than twenty (20) feet wide, a minimum of one (1) sun chart shall be taken from the bottom edge of the center of the solar energy system. If the solar energy system is greater than twenty (20) feet wide, a minimum of two (2) sun charts shall be taken, one (1) from the bottom edge of each end of the solar energy system.

18.70.030 Lot Classifications

Affected Properties. All lots shall meet the provisions of this Section and will be classified according to the following formulas and table:

FORMULA I:
Minimum N/S lot dimension for Formula I = 30' 0.445 + S Where: S is the decimal value of slope, as defined in this Chapter.

FORMULA II:
Minimum N/S lot dimension for Formula II = 10' 0.445 + S Lots whose north-south lot dimension exceeds that calculated by Formula I shall be required to meet the setback in Section (A), below.

Those lots whose north-south lot dimension is less than that calculated by Formula I, but greater than that calculated by Formula II, shall be required to meet the setback in Section (B), below.

Those lots whose north-south lot dimension is less than that calculated by Formula II shall be required to meet the setback in Section (C), below.

18.70.040 Solar Setbacks

A. Setback Standard A. This setback is designed to insure that shadows are no greater than six (6) feet at the north property line. Buildings on lots which are classified as Standard A, and zoned for residential uses, shall be set back from the northern lot line according to the following formula:
SSB = H - 6'
0.445 + S
WHERE:
SSB = the minimum distance in feet that the tallest shadow producing point which creates the longest shadow onto the northerly property must be set back from the northern property line.
H = the height in feet of the highest shade producing point of the structure which casts the longest shadow beyond the northern property line.
S = the slope of the lot, as defined in this Chapter.

B. Setback Standard B. This setback is designed to insure that shadows are no greater than sixteen (16) feet at the north property line.
Buildings for lots which are classified as Standard B or for any lot zoned C-1, E-1 or M-1, or for any lot not abutting a residential zone to the north, shall be set back from the northern lot line as set forth in the following formula:
SSB = H - 16'
0.445 + S

C. Setback Standard C. This setback is designed to insure that shadows are no greater than twenty-one (21) feet at the north property line.
Buildings for lots in any zone whose north/south lot dimension is less than Standard B shall meet the setback set forth in the following formula:
SSB = H - 21'
0.445 + S

D. Exempt Lots. Any lot with a slope of greater than thirty percent (30%) in a northerly direction, as defined by this Ordinance, shall be exempt from the effects of the Solar Setback Section.

E. Lots Affected By Solar Envelopes. All structures on a lot affected by a solar envelope shall comply with the height requirements of the solar envelope.

F. Exempt Structures.

1. Existing Shade Conditions. If an existing structure or topographical feature casts a shadow at the northern lot line at noon on December 21, that is greater than the shadow allowed by the requirements of this Section, a structure on that lot may cast a shadow at noon on December 21, that is not higher or wider at the northern lot line than the shadow cast by the existing structure or topographical feature. This Section does not apply to shade caused by vegetation.
2. Actual Shadow Height. If the applicant demonstrates that the actual shadow which would be cast by the proposed structure at noon on December 21, is no higher than that allowed for that lot by the provisions of this Section, the structure shall be approved. Refer to Table D for actual shadow lengths.

18.70.050 Solar Access Performance Standard

A. Assignment of Solar Factor. All land divisions which create new lots shall be designed to permit the location of a twenty-one (21) foot high structure with a setback which does not exceed fifty (50%) percent of the lot's north-south lot dimension. Lots having north facing (negative) slopes of less than fifteen percent (15%) (e.g., 10%), and which are zoned for residential uses, shall have a north-south lot dimension equal to or greater than that calculated by using Formula I. Lots having north facing (negative) slopes equal to or greater than fifteen percent (15%) (e.g., 20%), or are zoned for non-residential uses, shall have a north-south lot dimension equal to or greater than that calculated by using Formula II.

B. Solar Envelope. If the applicant chooses not to design a lot so that it meets the standards set forth in (A) above, a Solar Envelope shall be used to define the height requirements which will protect the applicable Solar Access Standard. The Solar Envelope, and written description of its effects, shall be filed with the land partition or subdivision plat for the lot(s).

18.70.060 Variances

A. Variances to this Chapter shall be processed as a Type I procedure, except that variances granted under subsection B of this Section may be processed as a Staff Permit. (Ord. 2484 S3, 1988)

B. A variance may be granted with the following findings being the sole facts considered by the Staff Advisor:

1. That the owner or owners of all property to be shaded, sign and record with the County Clerk on the affected properties' deed, a release form supplied by the City, which contains the following information:

a. The signatures of all owners or registered leaseholders who hold an interest in the property in question.
b. A statement that the waiver applies only to the specific building or buildings to which the waiver is granted.

c. A statement that the solar access guaranteed by this Section is waived for that particular structure and the City is held harmless for any damages resulting from the waiver.
d. A description and drawing of the shading which would occur, and

2. The Staff Advisor finds that:
a. The variance does not preclude the reasonable use of solar energy on the site by future buildings; and
b. The variance does not diminish any substantial solar access which benefits a habitable structure on an adjacent lot.
c. There are unique or unusual circumstances which apply to this site which do not typically apply elsewhere.

18.70.070 Solar Access Permit for Protection from Shading by Vegetation

A. A Solar Access Permit is applicable in the City of Ashland for protection of shading by vegetation only. Shading by buildings is protected by the setback provisions of this Ordinance.

B. Any property owner or lessee, or agent of either, may apply for a Solar Access Permit from the Staff Advisor. The application shall be in such form as the Staff Advisor may prescribe but shall, at a minimum, include the following:

1. A fee of fifty ($50.00) Dollars plus Ten ($10.00) Dollars for each lot affected by the Solar Access Permit.

2. The applicant's name and address, the owner's name and address, and the tax lot number of the property where the proposed solar energy system is to be located.

3. A statement by the applicant that the solar energy system is already installed or that it will be installed on the property within one (1) year following the granting of the permit.

4. The proposed site and location of the solar energy system, its orientation with respect to true south, and its slope from the horizontal shown clearly in drawing form.

5. A sun chart.

6. The tax lot numbers of a maximum of ten (10) adjacent properties proposed to be subject to the Solar Access Permit. A parcel map of the owner's property showing such adjacent properties with the location of existing buildings and vegetation, with all exempt vegetation labeled exempt.

7. The Solar Access Permit height limitations as defined in Section 18.70.050 of this Ordinance for each affected property which is necessary to protect the solar energy system from shade during solar heating hours. In no case shall the height limitations of the Solar Access Permit be more restrictive than the building setbacks.

C. If the application is complete and complies with this Ordinance, the Staff Advisor shall accept the solar access recordation application and notify the applicant. The applicant is responsible for the accuracy of all information provided in the application.

D. The Staff Advisor shall send notice by certified letter, return receipt requested, to each owner and registered lessee of property proposed to be subject to the Solar Access Permit. The letter shall contain, at a minimum, the following information:

1. The name and address of the applicant.

2. A statement that an application for a Solar Access Permit has been filed.

3. Copies of the collector location drawing, sun chart, and parcel map submitted by the applicant.

4. A statement that the Solar Access Permit, if granted, imposes on them duties to trim vegetation at their expense.

5. The advisability of obtaining photographic proof of the existence of trees and large shrubs.

6. The times and places where the application may be viewed.

7. Telephone number and address of the City departments that will provide further information.

8. That any adversely affected person may object to the issuance of the permit by a stated time and date, and how and where the objection must be made.

E. If no objections are filed within thirty (30) days following the date the final certified letter is mailed, the Staff Advisor shall issue the Solar Access Permit.

F. If any adversely affected person or governmental unit files a written objection with the Staff Advisor within the specified time, and if the objections still exist after informal discussions among the objector, appropriate City Staff, and the applicant, a hearing date shall be set and a hearing held in accordance with the provisions of Section 18.70.080.

18.70.080 Hearing Procedure

A. The Staff Advisor shall send notice of the hearing on the permit application to the applicant and to all persons originally notified of the Solar Access Permit application, and shall otherwise follow the procedures for a Type I hearing.

B. The Staff Advisor shall consider the matters required for applications set forth in Section 18.70.070(B) on which the applicant shall bear the burden of proof, and the following factor on which the objector shall bear the burden of proof: A showing by the objector that the proposed collector would unreasonably restrict the planting of vegetation on presently under-developed property.

1. If the objector is unable to prove these circumstances and the applicant makes the showings required by Section 18.70.060(B), the Staff Advisor shall approve the permit.

2. If the applicant has failed to show all structures or vegetation shading of the proposed collector location in his application, the Staff Advisor may approve the permit while adding the omitted shading structures or vegetation as exemptions from this Chapter.

3. If the objector shows that an unconditional approval of the application would unreasonably restrict development of the objector's presently under-developed property, the Staff Advisor may approve the permit, adding such exemptions as are necessary to allow for reasonable development of the objector's property.

4. If the Staff Advisor finds that the application contains inaccurate information which substantially affects the enforcement of the Solar Access Permit, the application shall be denied.

C. Any decision by the Staff Advisor is subject to review before the Planning Commission as a Type II planning action according to the usual procedures contained in this Title. (Ord. 2775, 1996)

18.70.090 Limits On Solar Access Permits

A. No Solar Access Permit may be filed which would restrict any lot which has an average slope of fifteen (15) percent in the northerly direction.

B. A Solar Access Permit becomes void if the use of the solar collector is discontinued for more than twelve (12) consecutive months or if the solar collector is not installed and

operative within twelve (12) months of the filing date of the Solar Access Permit. The applicant may reapply for a Solar Access Permit in accordance with Chapter 18.70.070, however, the application fee shall be waived.

18.70.100 Entry of Solar Access Permit Into Register

A. When a Solar Access Permit is granted, the Staff Advisor shall:

1. File the Solar Access Permit with the County Clerk. This shall include the owner's name and address and tax lot of the property where the recorded collector is to be located, any special exceptions or exemptions from the usual affects of a Solar Access Permit, and the tax lots of the ten (10) or fewer adjacent properties subject to the Solar Access Permit.

2. File a notice on each affected tax lot that the Solar Access Permit exists and that it may affect the ability of the property owner to grow vegetation, and that it imposes certain obligations on the property owner to trim vegetation.

3. Send a certified letter, return receipt requested, to the applicant and to each owner and registered lessee of property subject to the Solar Access Permit stating that such permit has been granted.

B. If a Solar Access Permit becomes void under Section 18.70.090(B), the Staff Advisor shall notify the County Clerk, the recorded owner, and the current owner and lessee of property formerly subject to the Solar Access Permit.

18.70.110 Effect and Enforcement

A. No City department shall issue any development permit purporting to allow the erection of any structure in violation of the setback provisions of this Chapter.

B. No one shall plant any vegetation that shades a recorded collector, or a recorded collector location if it is not yet installed, after receiving notice of a pending Solar Access Permit application or after issuance of a permit. After receiving notice of a Solar Access Permit or application, no one shall permit any vegetation on their property to grow in such a manner as to shade a recorded collector (or a recorded collector location if it is not yet installed) unless the vegetation is specifically exempted by the permit or by this Ordinance.

C. If vegetation is not trimmed as required or is permitted to grow contrary to Section 18.70.100(B), the recorded owner or the City, on complaint by the recorded owner, shall give notice of the shading by certified mail, return receipt requested, to the owner or registered lessee of the property where the shading vegetation is located. If the property owner or lessee fails to remove the shading vegetation within thirty (30) days after receiving this notice, an injunction may be issued, upon complaint of the recorded owner, recorded lessee, or the City, by any court of jurisdiction. The injunction may order the recorded owner or registered lessee to trim the vegetation, and the court shall order the violating recorded owner or registered lessee to pay any damages to the complainant, to pay court costs, and to pay the complainant reasonable attorney's fees incurred during trial and/or appeal.

D. If personal jurisdiction cannot be obtained over either the offending property owner or registered lessee, the City may have a notice listing the property by owner, address and legal description published once a week for four (4) consecutive weeks in a newspaper of general circulation within the City, giving notice that vegetation located on the property is in violation of this Ordinance and is subject to mandatory trimming. The City shall then have the power, pursuant to court order, to enter the property, trim or cause to have trimmed the shading parts of the vegetation, and add the costs of the trimming, court costs and other related costs as a lien against that property.

E. In addition to the above remedies, the shading vegetation is declared to be a public

nuisance and may be abated through Title 9 of the Ashland Municipal Code.

F. Where the property owner or registered lessee contends that particular vegetation is exempt from trimming requirements, the burden of proof shall be on the property owner or lessee to show that an exemption applies to the particular vegetation.

7. VIRGIN ISLANDS

§ 1001. Short title

This act shall be cited as the "Solar and Wind Energy Systems Act."

§ 1002. Declaration of findings and policy

The Legislature of the Virgin Islands finds and declares that the prohibitive costs of electrical power and the increasing occurrences of electrical power outages in the Virgin Islands requires the Government of the United States Virgin Islands to pursue serious consideration of other energy sources. Further, the use of renewable energy sources, such as solar energy and wind energy, will help to reduce continuing dependency and reliance on depletable energy resources such as oil, natural gas, and coal. Therefore, the Legislature declares that it is in the public interest to develop and expand solar and wind energy systems to meet the present and future energy needs of the Virgin Islands. The owner of a solar or wind energy system would be permitted to negotiate for assurance of continued access to the owner's energy source. Zoning regulations would be promulgated that would encourage and protect renewable energy systems.

§ 1003. Definitions

As used in this chapter, the term "solar or wind energy system" means any system that converts, stores, collects, protects or distributes the kinetic energy of the sun or wind into mechanical, chemical or electrical energy to provide power generation for the heating of water, the heating and cooling of buildings or other structures, and other similar purposes.

§ 1004. Prohibited conveyances

(a) Any covenant, condition, or restriction contained in any deed, contract, mortgage, security instrument, or other instrument pertaining to a conveyance, sale or transfer of real property or interest therein which prohibits or unreasonably limits the installation or use of a solar or wind energy system shall be void and unenforceable.
(b) A covenant, condition or restriction shall be considered "unreasonable" for the purposes of this chapter if it significantly increases the cost and expense of the solar or wind energy system to its owner or user, or significantly decreases its efficiency, or otherwise effectively discourages the installation or use of a solar or wind energy system.

§ 1005. Energy system height limitation

Notwithstanding the provisions of Title 29, chapter 3, Virgin Islands Code, a tower used in a solar or wind energy system may exceed the height limitation of the district in which it is located by no more than one hundred (100) feet.

§ 1006. Easement for solar or wind energy system; rules and regulations

(a) For a subdivision of land for which a preliminary plot or general subdivision plan, or any other plan or data is required pursuant to the provisions of Title 29, chapter 3, subchapter II, Virgin Islands Code, the Planning Director shall also require, as a condition of approval of such plan or plans, a dedication of easements for the purpose of assuring that each parcel or unit in the subdivision shall have the right to receive sunlight or wind across adjacent parcels or units in the subdivision.

(b) The Planning Director shall issue rules and regulations to effectuate the provisions of

this chapter and shall include therein the following:

(1) Standards for determining the exact dimensions and locations of such easements;

(2) Restrictions on vegetation, buildings and other objects which could obstruct the passage of sunlight or wind through such easements;

(3) Terms or conditions, if any, under which an easement may be revised or terminated; and

(4) Considerations of cost, feasibility, contour, and configuration of the parcels or units to be subdivided.

(c) Such an easement shall not result in reducing allowable densities on any segment of a parcel or unit of a subdivision which may be occupied by a building or other structure already constructed, or presently under construction, on October 3, 1984.

8. STATE OF WISCONSIN

66.0401 Regulation relating to solar and wind energy systems

66.0401(1)

(1) Authority to restrict systems limited. No county, city, town, or village may place any restriction, either directly or in effect, on the installation or use of a solar energy system, as defined in s. 13.48 (2) (h) 1. g., or a wind energy system, as defined in s. 66.0403 (1) (m), unless the restriction satisfies one of the following conditions:

66.0401(1)(a)
(a) Serves to preserve or protect the public health or safety.
66.0401(1)(b)
(b) Does not significantly increase the cost of the system or significantly decrease its efficiency.
66.0401(1)(c)
(c) Allows for an alternative system of comparable cost and efficiency.
66.0401(2)

(2) Authority to require trimming of blocking vegetation. A county, city, village, or town may provide by ordinance for the trimming of vegetation that blocks solar energy, as defined in s. 66.0403 (1) (k), from a collector surface, as defined under s. 700.41 (2) (b), or that blocks wind from a wind energy system, as defined in s. 66.0403 (1) (m). The ordinance may include, but is not limited to, a designation of responsibility for the costs of the trimming. The ordinance may not require the trimming of vegetation that was planted by the owner or occupant of the property on which the vegetation is located before the installation of the solar or wind energy system.

236.292 Certain restrictions void
236.292(2)
(2) All restrictions on platted land that prevent or unduly restrict the construction and operation of solar energy systems, as defined in s. 13.48 (2) (h) 1. g., or a wind energy system, as defined in s. 66.0403 (1) (m), are void.

9. STATE OF FLORIDA

SOLAR RIGHTS LAW (Sections 163.04 and 718.113, Florida Statutes)

163.04 Energy devices based on renewable resources

(1) Notwithstanding any provision of this chapter or other provision of general or special law, the adoption of an ordinance by a governing body, as those terms are defined in this chapter, which prohibits or has the effect of prohibiting the installation of solar collectors, clotheslines, or other energy devices based on renewable resources is expressly prohibited.

(2) A deed restriction, covenant, declaration, or similar binding agreement may not prohibit or have the effect of prohibiting solar collectors, clotheslines, or other energy devices based on renewable resources from being installed on buildings erected on the lots or parcels covered by the deed restriction, covenant, declaration, or binding agreement. A property owner may not be denied permission to install solar collectors or other energy devices by any entity granted the power or right in any deed restriction, covenant, or similar binding agreement to approve, forbid, control, or direct alteration of property with respect to residential dwellings and within the boundaries of a condominium unit. Such entity may determine the specific location where solar collectors may be installed on the roof within an orientation to the south or within 45° east or west of due south if such determination does not impair the effective operation of the solar collectors.

(3) In any litigation arising under the provisions of this section, the prevailing party shall be entitled to costs and reasonable attorney's fees.

(4) The legislative intent in enacting these provisions is to protect the public health, safety, and welfare by encouraging the development and use of renewable resources in order to conserve and protect the value of land, buildings, and resources by preventing the adoption of measures which will have the ultimate effect, however unintended, of driving the costs of owning and operating commercial or residential property beyond the capacity of private owners to maintain. This section shall not apply to patio railings in condominiums, cooperatives, or apartments.

718.113. Maintenance; limitation upon improvement; display of flag; hurricane shutters.

(6) Notwithstanding the provisions of this section or the governing documents of a condominium or a multicondominium association, the board of administration may, without any requirement for approval of the unit owners, install upon or within the common elements or association property solar collectors, clotheslines, or other energy-efficient devices based on renewable resources for the benefit of the unit owners.

SOLAR ENERGY SALES TAX EXEMPTION (Chapter 212, Florida Statutes)

212.02 (26) "Solar energy system" means the equipment and requisite hardware that provide and are used for collecting, transferring, converting, storing, or using incident solar energy for water heating, space heating, cooling, or other applications that would otherwise require the use of a conventional source of energy such as petroleum products, natural gas, manufactured gas, or electricity.

212.08 (hh) Solar energy systems. Also exempt are solar energy systems or any component thereof. The Florida Solar Energy Center shall from time to time certify to the department a list of equipment and requisite hardware considered to be a solar energy system or a component thereof.

SOLAR ENERGY STANDARDS ACT (Section 377.705, Florida Statute)

377.705 Solar Energy Center; development of solar energy standards.

(1) SHORT TITLE. This act shall be known and may be cited as the Solar Energy Standards Act of 1976.

(2) LEGISLATIVE FINDINGS AND INTENT

(a) The Legislature recognizes that if present trends continue, Florida will increase present energy consumption six fold by the year 2000. Because of this dramatic increase and because existing domestic conventional energy resources will not provide sufficient energy to meet the nation's future needs, new sources of energy must be developed and applied. One such source, solar energy, has been in limited use in Florida for 30 years. Applications of incident solar energy, the use of solar radiation to provide energy for water heating, space heating, space cooling, and other uses, through suitable absorbing equipment on or near a residence or commercial structure, must be extensively expanded. Unfortunately, the initial costs with regard to the production of solar energy have been prohibitively expensive. However, because of increases in the cost of conventional fuel, certain applications of solar energy are becoming competitive, particularly when life-cycle costs are considered. It is the intent of the Legislature in formulating a sound and balanced energy policy for the state to encourage the development of an alternative energy capability in the form of incident solar energy.

(b) Toward this purpose, the Legislature intends to provide incentives for the production and sale of, and to set standards for, solar energy systems. Such standards shall ensure that solar energy systems manufactured or sold within the state are effective and represent a high level of quality of materials, workmanship, and design.

(3) DEFINITIONS

(a) "Center" is defined as the Florida Solar Energy Center of the Board of Regents.

(b) "Solar energy systems" is defined as equipment which provides for the collection and use of incident solar energy for water heating, space heating or cooling, or other applications which normally require or would require a conventional source of energy such as petroleum products, natural gas, or electricity and which performs primarily with solar energy. In such other systems in which solar energy is used in a supplemental way, only those components which collect and transfer solar energy shall be included in this definition.

(4) FLORIDA SOLAR ENERGY CENTER TO SET STANDARDS, REQUIRE DISCLOSURE, SET TESTING FEES

(a) The center shall develop and promulgate standards for solar energy systems manufactured or sold in this state based on the best currently available information and shall consult with scientists, engineers, or persons in research centers who are engaged in the construction of, experimentation with, and research of solar energy systems to properly identify the most reliable designs and types of solar energy systems.

(b) The center shall establish criteria for testing performance of solar energy systems and shall maintain the necessary capability for testing or evaluating performance of solar energy systems. The center may accept results of tests on solar energy systems made by other organizations, companies, or persons when such tests are conducted according to the criteria established by the center and when the testing entity has no vested interest in the manufacture, distribution or sale of solar energy systems.

(c) The center shall be entitled to receive a testing fee sufficient to cover the costs of such testing. All testing fees shall be transmitted by the center to the Chief Financial Officer to be deposited in the Solar Energy Center Testing Trust Fund, which is hereby created in the State Treasury, and disbursed for the payment of expenses incurred in testing solar energy systems.

(d) All solar energy systems manufactured or sold in the state must meet the standards established by the center and shall display accepted results of approved performance tests in a manner prescribed by the center.

Solar America Board for Codes and Standards

www.solarabcs.org

Wind Load Calculations for PV Arrays

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June 2010

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Download a copy of the report:
www.solarabcs.org/windload

Executive Summary

Today's photovoltaic (PV) industry must rely on licensed structural engineers' various interpretations of building codes and standards to design PV mounting systems that will withstand wind-induced loads. This is a problem, because–although permitting agencies require assessments of the structural attachment of solar equipment to rooftops—the safety and sufficiency of these attachments are not adequately addressed in any codes or standards. The result is a multitude of code interpretations from a range of individuals and groups, often yielding different design loads for the same design specifications.

It is important to evaluate equipment and attachment methods to ensure that PV equipment will remain attached to structures during windstorm events, and that additional loads or load concentrations do not exceed the structural capacity of the building. *ASCE Standard-7-05 (American Society of Civil Engineers Standard 7-05)* is the standard for wind forces on structures, but it does not provide adequate guidance to the design professionals and code officials tasked with assessing PV installations.

This lack of guidance creates obstacles for the PV industry. The resulting problems include frustrated installers, unhappy customers, and wind-related structural failures. In addition, uncertainty about what constitutes a safe and secure installation for a given wind load can slow or even stop the approval process for PV installations and complicates the training of code officials.

In this report, we provide sample calculations for determining wind loads on PV arrays based on *ASCE Standard 7-05.* We focus on applying the existing codes and standards to the typical residential application of PV arrays mounted parallel to the roof slope and relatively close (3 to 6 inches) to the roof surface. We do not address other array configurations or building-integrated PV.

It will require much more work to gather information and develop standards specific to wind loading on rooftop PV installations. Although the information in this report does not completely solve the problem, it does provide initial guidance to designers and code officials.

In this paper, we recommend an approach for the structural design of roof-mounted PV systems based on *ASCE Standard 7-05*. We provide examples that demonstrate a step-by-step procedure for calculating wind loads on PV arrays. The approach is applicable to PV modules mounted on rooftops that are no more than 60 feet high, when the PV array is oriented parallel to the roof surface, and when the mounting structure is sufficiently rigid. The PV array should be mounted a maximum of six inches above the roof surface. This distance is measured from the bottom of the PV frame to the roof surface, and is based on assumptions about typical mounting system configurations. The building should meet all requirements listed in Section 6.4.1.1 of *ASCE Standard 7-05*.

> "*ASCE Standard-7-05*. . . does not provide adequate guidance to the design professionals and code officials tasked with assessing PV installations."

It is important that design professionals read and understand the appropriate codes and standards when designing rooftop PV systems. This report is not meant to be a substitute for existing codes and standards. It is also important for design professionals to stay current with existing codes and standards, because we expect the body of information about designing PV systems to withstand local wind loading to grow rapidly in the near future.

Recommendations

1. At present, we recommend basing the structural design of roof-mounted PV systems on the *ASCE Standard 7-05* as follows:
   a. Section 6.5.12.2, main wind-force resisting system (MWFRS), is the recommended starting point for designing the PV mounting structure, with the PV module oriented above and parallel to the roof surface.

b. Section 6.5.12.4.1 addresses wind loads on components and cladding. We recommend the use of Section 6.5.12.4.1 and supporting Figures only for the design of the PV module attachment clips and hardware to the structure, and for calculating loads on individual PV modules.

c. We do not recommend Section 6.5.15, 6.5.15.1, and Figure 6-21 for the design of PV systems.

d. This report provides basic guidance for applying *ASCE Standard 7-05* to existing codes and standards for the typical residential application of PV arrays mounted parallel to the roof slope and relatively close (3 to 6 inches) to the roof surface.

2. We recommend wind tunnel testing be conducted for the most common rooftop PV installations to verify methods and calculations. The installation types include stand-off mounting parallel to the roof, stand-off mounting at an incline relative to the roof, and ballasted installations on flat roofs.

3. We recommend that codes and standards be modified to specifically address the mounting of PV arrays to rooftops to eliminate potential barriers to market development in high wind regions.

4. We recommend that local jurisdictions and design professionals use the recommendations in this report to ensure continuity in interpreting existing codes and standards.

Author Biographies

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Stephen Barkaszi, P.E. is a Senior Research Engineer in the Solar Energy Division at the Florida Solar Energy Center (FSEC). Mr. Barkaszi's areas of research include photovoltaic (PV) module and system testing and certification, distributed generation, utility-interconnection issues, building-integrated PV, and roof-mounted PV arrays. He also conducts research on high performance buildings and has been involved in the Zero Energy Homes (ZEH) efforts at FSEC since 1998. The ZEH projects have led to Disaster Tolerant Structures, which incorporate super energy efficient design with on-site generation for short and long-term power outages caused by wind storms and hurricanes in Florida or other coastal areas. Mr. Barkaszi's teaching activities include various seminars and short courses on PV, building energy efficiency, and building systems design. One popular offering is the week-long course *Installing Photovoltaic Systems* that FSEC offers each month. He received his B.S. and M.S. degrees in ocean engineering from the Florida Institute of Technology. Mr. Barkaszi is a licensed civil engineer in the state of Florida and previously managed the construction materials testing division for a private civil engineering firm.

Colleen O'Brien

Colleen O'Brien, P.E. has worked in the PV industry since 1996. She managed the Testing and Reliability group at PowerLight (now SunPower) for nine years, where she was responsible for mechanical and electrical testing of photovoltaic (PV) modules and mounting hardware. In that capacity, she ensured wind and seismic code compliance of PV mounting hardware, oversaw wind tunnel test programs, monitored and analyzed data from fielded PV systems, and evaluated emerging PV technologies. Ms. O'Brien continued this work in her current position with the consulting firm BEW Engineering, where she has expanded the scope of her expertise to include PV energy forecasting and system code compliance. She earned a B.S. in mechanical engineering from the University of New Hampshire and is a registered professional mechanical engineer in the state of California.

Solar America Board for Codes and Standards

The Solar America Board for Codes and Standards (Solar ABCs) provides an effective venue for all solar stakeholders. A collaboration of experts formally gathers and prioritizes input from groups such as policy makers, manufacturers, installers, and large- and small-scale consumers to make balanced recommendations to codes and standards organizations for existing and new solar technologies. The U.S. Department of Energy funds Solar ABCs as part of its commitment to facilitate widespread adoption of safe, reliable, and cost-effective solar technologies.

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Acknowledgements

This material is based upon work supported by the Department of Energy under Award Number DE-FC36-07GO17034.

Table of Contents

Disclaimer ii

Executive Summary iii

Author Biographies v

Introduction 1

Background 1

- Existing Codes and Standards 1
- Discussion 2

Sample Calculations 4

- Sample Calculation 1 4
- Sample Calculation 2 13

Conclusion 16

Recommendations 17

References 18

Acronyms 18

Glossary 18

Introduction

Today's photovoltaic (PV) industry must rely on licensed structural engineers' various interpretations of building codes and standards to design PV mounting systems that will withstand wind-induced loads. Ensuring that PV installations are safe and secure can involve custom testing methods such as wind tunnel testing or computer simulations, which are acceptable if approved by a structural engineer. The result is a multitude of code interpretations from a range of individuals and groups, often yielding different design loads for the same design specifications.

Please note that Chapter 6 of the ASCE Standard 7-05 *describes the procedure for determining wind loads on buildings and structures. All figures, tables, and sections of Chapter 6 begin with the prefix "6." For example, Figure 6-10, Table 6-3, and Section 6.3 are all parts of* ASCE Standard 7-05*, Chapter 6. These conventions have been adopted in this report, therefore any references to tables and figures beginning with a "6" refer to tables and figures in* ASCE Standard 7-05*, while those that do not begin with a "6" are contained within the body of this report.*

Background

The American Society of Civil Engineers (ASCE) *Minimum Design Loads for Buildings and Other Structures* (*ASCE Standard 7-05*) is the most comprehensive wind design standard in the United States. Other building codes such as the International Building Code (IBC) contain wind design requirements that are less comprehensive than *ASCE Standard 7-05*. This is especially true for design problems with atypical building geometry such as roof-mounted PV systems.

Fortunately, the IBC and other building codes explicitly permit the use of the *ASCE Standard 7-05* for the design of buildings and structures. However, it is difficult—and in some cases inappropriate—to derive the design loads on roof-mounted PV arrays from the existing standards, because there is no specific provision for these structures. The recommended design approach for roof-mounted PV systems presented in this report is based on the most recent version of the ASCE standard, *ASCE Standard 7-05* (ASCE 2006). This work is an initial attempt to provide some guidance to design professionals and begin a dialogue in the PV community that will move this issue further toward consensus.

Existing Codes and Standards

In this report, we recommend an approach for the structural design of roof-mounted PV systems that is based on the *ASCE Standard 7-05*. We provide examples that demonstrate a step-by-step procedure for calculating wind loads on PV arrays. Our approach is applicable to PV modules mounted on rooftops that are no more than 60 feet high, when the modules are oriented parallel to the roof surface, the mounting structure is sufficiently rigid, and the PV array is mounted a maximum of six inches above the roof surface. This distance is measured from the bottom of the PV frame to the roof surface and is based on assumptions about typical mounting system configurations. The building should meet all requirements listed in Section 6.4.1.1 of *ASCE Standard 7-05*.

> "The result is a multitude of code interpretations from a range of individuals and groups, often yielding different design loads for the same design specifications."

Existing codes and standards do not cover PV modules oriented at an angle to the roof surface, and an analysis of this configuration is beyond the scope of this report. Designing for wind loading on this type of orientation and mounting structure is significantly more complex than designing for modules parallel and close to the roof, and will require further research and possible testing. This report also does not address building-integrated PV.

[1] Note: *ASCE Standard 7-05,* Section 6.2, defines rigid buildings and structures as having a fundamental frequency of at least 1 Hz. The 1 Hz limitation was developed as a worst-case value for high-rise buildings, and the application of this limitation has been the subject of some controversy in the ASCE community. PV

mounting structures are typically less than 10 feet in height and often substantially shorter, and will likely have a fundamental frequency higher than 1 Hz. *ASCE Standard 7-05* supports adopting the 1 Hz limitation for PV systems, but this should be verified as applicable by a licensed structural engineer on a case-by-case basis. Defining a maximum fundamental frequency for rigid PV structures will require further testing.

Experts in the areas of PV system design, aerodynamics, wind tunnel testing, and ASCE Standard 7-05 conducted a thorough review of the code. Based on this review, the team concluded that:

1. Unfortunately, there is no prescribed method in the standard that clearly addresses the specific geometry of roof-mounted PV systems.
2. Sections 6.5.15 and 6.5.15.1 and Figure 6-21 are not recommended for the design of PV systems.
3. Section 6.5.12.4.1 addresses wind loads on components and cladding, but the use of this section and the supporting figures are recommended only for the design of the PV module attachment clips and hardware to the structure, and for calculating loads on individual PV modules.
4. Section 6.5.12.2 (main wind-force resisting system [MWFRS]) is the recommended starting point for designing the PV mounting structure with the PV module oriented above and parallel to the roof surface.

Discussion

We studied Section 6.5.15, 6.5.15.1, Figure 6-21, and the commentary on Figure 6-21 in *ASCE Standard 7-05* to determine their potential applicability to roof-mounted PV systems. Section 6.5.15.1, "Rooftop Structures and Equipment for Buildings with h < /= 60 feet" is a new addition to this version of the standard. The text would appear to be applicable to PV systems.

However, it is the opinion of the authors that this was due to a lack of clarity in the actual text. This section of the standard was intended to be applicable to roof-mounted structures with a prismatic shape, such as chimneys, air conditioners, etc. It was not intended for rooftop installations like PV systems that have gaps between the equipment and the roof. These gaps can allow pressurization below the surface of the PV modules independent of pressure in the building interior.

Put another way, *ASCE Standard 7-05* was written for buildings, not the tops of buildings. Wind loading for installations like PV systems that leave gaps between the equipment and the roof surface is very different from wind loading for roof-mounted structures with a prismatic shape. For this reason, the authors do not recommend the use of Section 6.5.15.1 or Figure 6-21 for the design of PV systems.

> "Unfortunately, there is no prescribed method in the standard that clearly addresses the specific geometry of roof-mounted PV systems.."

Section 6.5.12.4.1 addresses wind loads on components and cladding. "Components and cladding" is defined by ASCE as an "element of the building that does not qualify as the MWFRS." Many structural engineers and PV designers have considered roof-mounted PV systems to qualify as components and cladding, and not the MWFRS, due to the fact that the PV support structure is not the wind resisting structure for the building. The MWFRS is defined by ASCE as "an assemblage of structural elements assigned to provide support and stability for the overall structure. The system generally receives wind loading from more than one surface."

Components receive wind forces directly or from the cladding system. Those loads are transferred to the MWFRS, which bears the structural loads. Based on the descriptions of

the differences between components and cladding and the MWFRS, we concluded that the PV modules themselves and the hardware that secures the modules to the structure could be considered components and cladding. However, the means of attachment to the roof is the MWFRS, because the PV mounting system provides support and stability for the overall structure. It is this means of attaching the modules to the structure (via the roof) that is of primary concern. Therefore, we recommend using Section 6.5.12.4.1 and the supporting figures for calculating loads on individual PV modules and attachment hardware, and Section 6.5.12.2 for the design of PV rooftop mounting structures.

ASCE Standard 7-05 differentiates between components and cladding and the MWFRS because the small tributary area of components and cladding can result in higher instantaneous loads than the MWFRS. Components and cladding transfer loads to the MWFRS. At one instant in time, some of the components and cladding may experience extreme uplift while others experience less uplift or even a downward force. The MWFRS can distribute these varying loads, and the net effect is reduced wind loading on the structure. Section 6.5.12.4.1 provides a procedure for calculating wind loads on components and cladding, and 6.5.12.2 provides a procedure for calculating wind loads on the MWFRS. These are the recommended starting points for designing mounting structures for roof-mounted PV installations in which the PV module is oriented parallel to the roof surface.

Although the referenced figures in 6.5.12.2 have geometries that appear to be similar to tilted PV modules, we do not recommend applying this section to modules oriented at a tilt relative to the roof surface. None of the referenced figures in this section address the geometry of tilted PV, which is inherently non-aerodynamic when it is mounted on top of a building. Future work will include the consideration of analytical techniques based on fundamentals of aerodynamics, combined with publicly available wind tunnel test data as well as data in *ASCE Standard 7-05* to develop a procedure for estimating loads for tilted modules. Although wind tunnel testing would be the preferred solution, sufficient information is not currently available, and empirical data analysis is left to future studies.

When modules are oriented parallel to the roof surface—provided that they are mounted close to the roof—they are subjected to the same type of wind flow as a roof at the same pitch. Based on typical roof-mounted PV array hardware configurations and current practices, the authors recommend limiting the PV array height to six inches above the roof in order to use the approaches discussed in this report. It is unknown at this time how much internal pressurization (positive pressure below the module) will be created because of the gap distance between the roof and module frame (the opening) and the distance between the roof and the back of the module (the structural diaphragm). Although *ASCE Standard-7-05* does provide values for internal pressure coefficients, these coefficients were developed for buildings more than 15 feet tall with various types of openings around the building that are specific to common buildings—open (at least 80% of each wall is open), enclosed (walls have very few openings), or partially enclosed (walls have some openings). The geometry of the air space below the PV module could be categorized similarly. However, while analogous, it may be very different from the geometry of the walls and interior airspace of a building because of the significant scaling differences.

The problem of not having accurate internal pressure coefficients for common PV geometries is a key weakness in applying the *ASCE Standard 7-05* to roof-mounted PV systems. Of the three building classifications described in *ASCE Standard 7-05*, one could easily justify classifying the PV module as an "open building," (internal pressure coefficient GCpi = 0), which would yield the lowest wind load of the three options. Given the proximity of the PV module to the roof, and the presence of structural and electrical components between the modules and the roof, one could also consider the module as

a "partially enclosed" building (internal pressure coefficient GCpi = +/- 0.55), which would yield the highest wind load of the three options.

Based on discussions with experts in the field of wind tunnel testing and the ASCE Standard, we believe that a value of +/- 0.1 to +/-0.3 is a reasonable choice for systems with limited restrictions to airflow below the module. Some authorities having jurisdiction (AHJs) or structural engineers may require designers to apply the classification of a partially enclosed building. However, we expect that most AHJs will defer the decision to a licensed engineer.

The decision about how conservative a designer should be when choosing an internal pressure coefficient may also be influenced by the potential reduction in wind loads most PV systems experience due to pressure equalization. *ASCE Standard 7-05* does not account for this reduction.

With stand-off mounted PV systems parallel to the roof, most of the uplift load on modules is due to pressure differentials above and below the module. The difference in pressure between the top and bottom surface gives the total uplift or downward pressure acting on the module. Because modules have a relatively small area compared to roofs, and because there are typically one-half to two-inch gaps between modules, pressure differentials above and below modules typically equalize in a short amount of time, on the order of fractions of seconds. *ASCE Standard 7-05* does acknowledge the phenomenon of pressure equalization in the discussion of "air permeable cladding" in Section 6.4.3, because pressure equalization is entirely dependent upon the geometry of the cladding. Properties that affect the amount of pressure equalization are the length and width of the module (smaller modules will have better equalization, larger modules will take longer to equalize), the vertical distance of the module from the roof surface (closer to the roof will reduce the volume of air to pressure equalize), the horizontal distance between modules (larger distances will create a better path for pressure transmission), and the degree of restriction to airflow below the module due to the presence of structural or electrical components (fewer restrictions will enhance pressure equalization).

Because PV modules are typically close to the roof surface and have gaps on all sides, pressure differentials between the top and back of the PV surface likely equalize quickly. This phenomenon could reduce wind loads on the module by 50% to 80% or even more, but quantifying the degree of pressure equalization that occurs in various PV systems will require wind tunnel testing on a variety of geometric configurations.

Sample Calculations

In Sample Calculation 1, we determine wind loads on a PV mounting structure based on the assumption that it is part of the MWFRS. In Sample Calculation 2, we outline how a designer should determine wind loads on PV modules and mounting hardware.

Again, this approach is limited to applications in which the PV module is oriented parallel to the roof surface and is a maximum of about six inches above the roof deck. In addition, the building must be 60 feet high or less and the mounting structure should have a fundamental frequency of 1 Hz or greater.

Sample Calculation 1

Wind Load on PV Mounting Structure (MWFRS, Section 6.5.12.2)

Location: Phoenix, Arizona

Terrain: Open desert, very few buildings.

Building height: 17'3" at the eave, 22'9" at the ridge, 20' mean roof height

Building shape: Gable roof with a 20° pitch

Building type: Residential

Building dimensions: 60’ (along the ridge) x 30’ (perpendicular to the ridge)

Module orientation: Parallel to roof, 5” above roof surface, minimum 4’ from the roof edge.

PV array area: 100 square foot array (10’ x 10’)

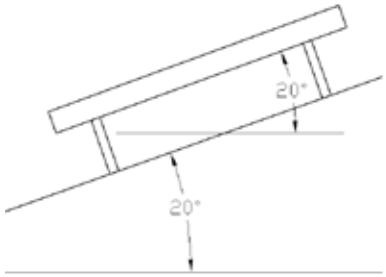


Figure 1. Array mounted parallel to the roof slope

Steps:

1. Reference Figure 6-1 to determine the basic wind speed for the Phoenix, Arizona, location. From this Figure, the wind speed is V = 90 mph.
2. Reference Section 6.5.6.3 to determine the surface roughness category. Do a physical site inspection or review photographs of the surrounding terrain in all directions to properly classify the surrounding terrain using the definitions in this section. If the terrain varies in the upwind direction or if the location is in a transitional zone, use the worst-case wind loads. For this sample problem, we assumed that Exposure C applies for this open desert location.
3. Determine the occupancy category using Table 1-1. In this case, it is Type II for a residential building.
4. Determine the importance factor using Table 6-1. In this case, I = 1.00 for a Type II building.
5. Reference Section 6.5.7.1 to determine the topographic factor, K_{zt}. For this sample calculation, we will assume that the site is on level terrain, so K_{zt} = 1.0.
6. Determine a velocity pressure exposure coefficient using Table 6-3. As discussed in the definition of the height (h) in Section 6.3, use the mean roof height (note that eave height is used for a roof pitch < 10°). The mean height in this case is 20 feet. For an exposure terrain classification of C, and a roof height of 20, we obtain a velocity pressure exposure coefficient of K_z = 0.90.
7. Determine enclosure classification and internal pressure coefficients (GCpi). Section 6.2 provides definitions of enclosure types (open, partially enclosed, and enclosed buildings), and the designer must identify the enclosure classification in order to determine the internal pressure coefficients. Many racking systems create very little obstruction below the PV module, which may lead the designer to choose an “open building” classification. However, the typically small vertical space (on the order of 3 to 6 inches), as well as the PV frame, wiring, conduit, and structural components below the module will cause a restriction in airflow. For this reason, the PV array could also be considered to be a “partially enclosed building.” Sections 6.5.3, 6.5.11.1, and ultimately Figure 5 provide internal pressure coefficients for the various enclosure classifications. In actuality, most PV systems likely have internal pressure coefficients somewhere between those given for an open building (GCPi = 0) and a partially enclosed building (GCpi +/-0.55). Based on consultations with numerous wind loading experts and engineers, we recommend a range of +/-0.1 to +/-0.3. Because the ASCE Standard is not clear, a designer could justify classifying the PV array as an open building (GCpi = 0), but our recommendation provides an added margin of safety.

Some AHJs or structural engineers may require a more conservative value of GCpi = +/0.55. In this sample calculation, we used a value of GCpi = +/- 0.3.

8. Determine external pressure coefficient. To select the correct data from Figure 6-6 for buildings more than 60 feet high or Figure 6-10 for buildings less than 60 feet high, the designer must consider the geometry of the roof. However, Figure 6-18A through 6-18D should be used in place of Figures 6-6 or 6-10 for buildings with no walls (see the definition in Section 6.2 for Free Roofs). In our example, the building is a residence, which we assume is an enclosed or partially enclosed building with a roof that has a 20-degree pitch. We took the external pressure coefficients from Figure 6-10 for this sample building.

Figure 6-10 shows eight basic load combinations, illustrated in the eight building images and the "reference corners" on the first page of Figure 6-10. For buildings more than 30 feet high, there are two torsional load cases to consider. To calculate wind loads on the 10-foot by 10-foot PV array on the roof of our sample 20-foot tall building, the application of Figure 6-10 can be greatly simplified to one load case, although the result will be slightly conservative. We present a simplified process in this section of this report (see Figure 3), but first we propose a more rigorous application of Figure 6-10.

Figure 1 A, B, C, and D and Figure 2 A, B, C, and D show how we applied ASCE Figure 6-10 to the sample rooftop PV array. Each of the eight images corresponds to the load cases shown in the images on the first page of Figure 6-10. The first four images are used for the design of the PV mounting structure when analyzing loads on components in a transverse direction (the "Direction of MWFRS Being Designed" arrows in ASCE Figure 6-10 and the red arrows in Figure 1 A-D and Figure 2 A-D). The second four images are used for designing the structure when analyzing loads in a longitudinal direction.

Note that each image has a "reference corner." When wind hits the corner of a building, wind loads on the roof reach a peak. Rather than require that the building be designed under the assumption that each corner is subjected to a "corner wind load" at the same moment in time, which is not possible, *ASCE Standard 7-05* allows designers to analyze loads on the building one corner at a time. The same can be done for the PV mounting structure, although the analysis can be simplified as we discuss later in this section. The reference corners in each of the images represent the upwind corner of the building at one moment in time.

The zones that are applicable to the sample rooftop PV system on a 20-foot tall building are 2, 3, 2E, and 3E. The other zones in Figure 6-10 are applicable only to walls. The "E" in these zone categories stands for "edge." The differentiation between edge and interior regions is important, because upwind edge locations on a roof are known to have higher wind loads than interior regions. For this reason, it is wise to place PV arrays as far from the edges of buildings as possible. As shown in Figure 1 A-D and Figure 2 A-D, various parts of the sample PV array are situated in each of these zones, depending on the direction of the structural component being analyzed (transverse or longitudinal) and the upwind reference corner.

In order to define the boundaries zones 2, 3, 2E, and 3E, the designer must determine the dimension noted as 'a' in Figure 6-10. Figure 6-10 defines 'a' as "10% of the least horizontal dimension or 0.4h, whichever is smaller, but not less than 4% of the least horizontal dimension or 3 feet." We determined the value for 'a' for this building follows:

1. 10% of the least horizontal dimension for this building is 0.10 times the smallest horizontal building dimension of 30' = 3'.
2. 0.4 times the building height (h, defined in Section 6.3) for this building is 0.4 times the mean roof height. The mean roof height is 20'; 0.4 x 20' = 8'.
3. 4% of the least horizontal dimension is 0.04 x 30' = 1.2'.
4. Applying the definition of 'a' in the previous paragraph and calculations 1, 2, and 3, we obtain a = 3'.

Figure 6-10 shows edge and interior roof zones, defined as the area within a distance of two times a, or six feet from the upwind edge. The edge regions are shown in Figure 1 A-D and Figure 2 A-D as dark shaded areas on our sample rooftop system.

The second page of Figure 6-10 is used to identify the applicable external pressure coefficients for the sample building. For a 20-degree pitched roof, these values are shown below in Table 1.

Table 1: External Pressure Coefficients for Sample Calculation 1

Zone	GCpf
2	-0.69
3	-0.48
2E	-1.07
3E	-0.69

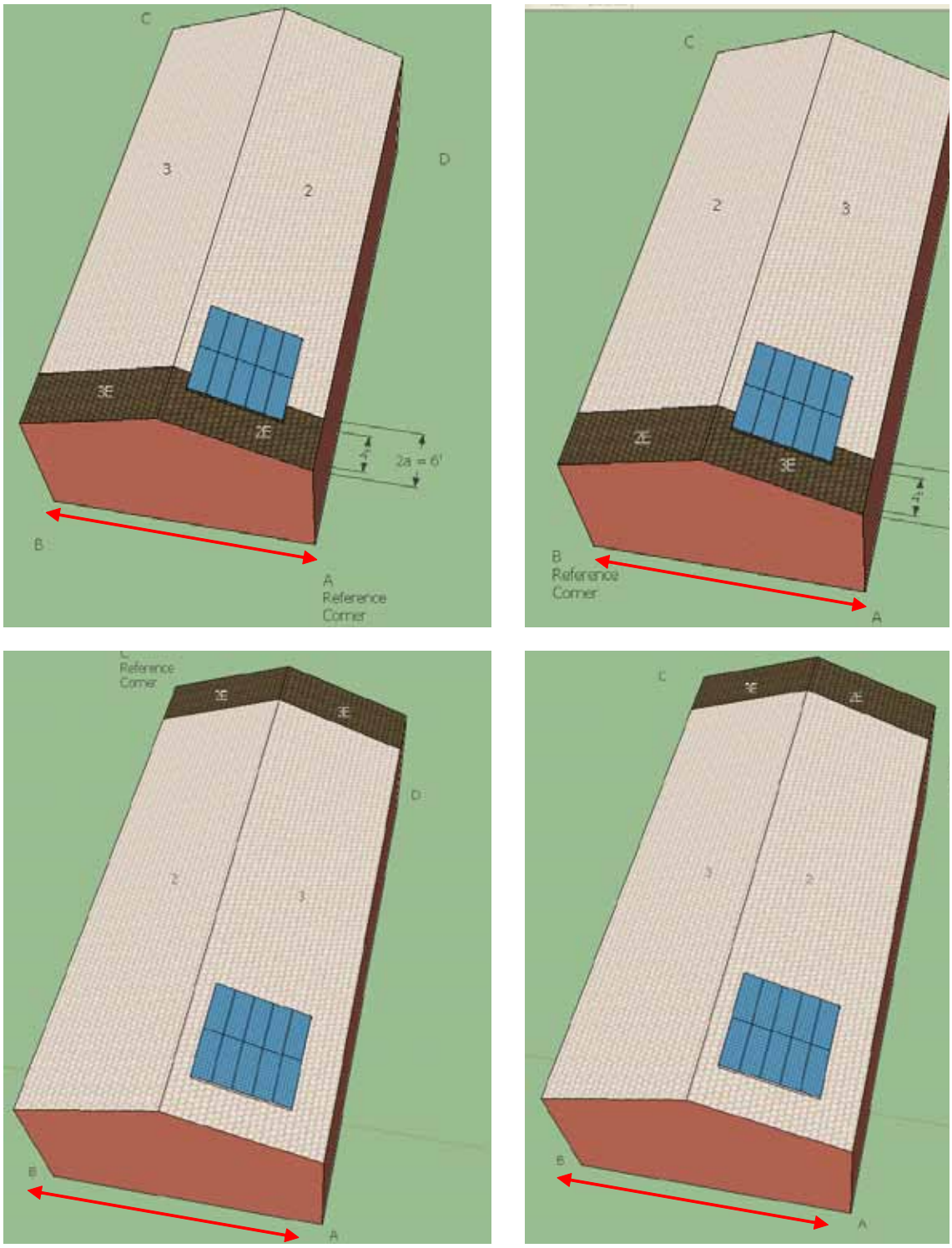


Figure 1-A, B, C, and D: Roof zones for Sample Calculation 1, based on ASCE Figure 6-10 and the geometry of the sample building. Red arrows indicate the direction of the structural members being designed (transverse direction).

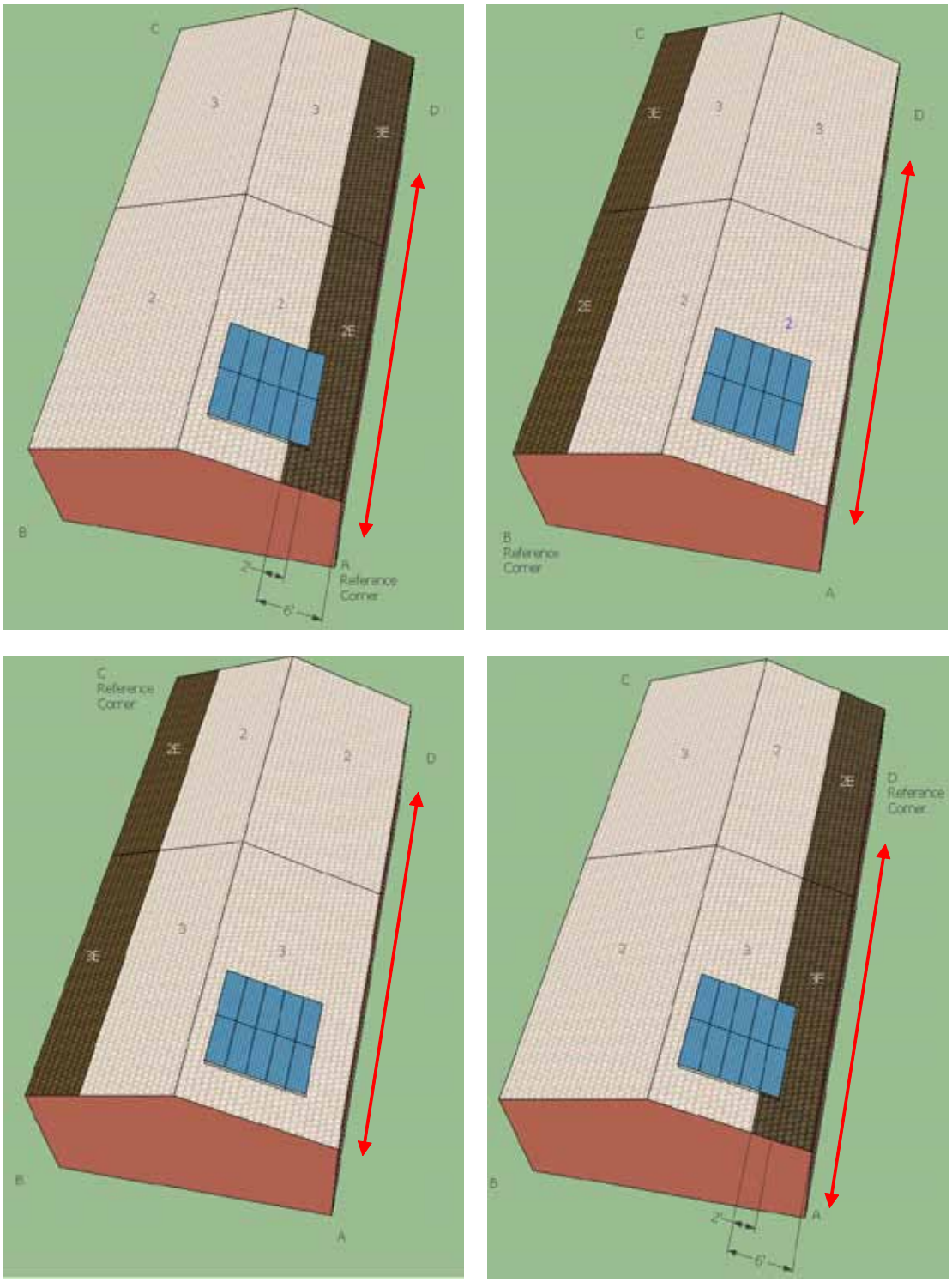


Figure 2 A, B, C, and D: Roof zones for Sample Calculation 1, based on ASCE Figure 6-10 and the geometry of the sample building. Red arrows indicate the direction of the structural members being designed (longitudinal direction).

9. Calculate velocity pressure as described in Section 6.5.10:

$$q_h = 0.00256 * K_z * K_{zt} * K_d * V^2 * I \text{ (in pouns per square foot [psf])}$$

$$q_h = 0.00256 * 0.90 * 1 * 1 * 90^2 * 1 = 19 \text{ psf}$$

10. Determine the design wind pressure as described in Section 6.5.12.2.1:

$$p = q * (GC_{pf} - GC_{pi})$$

In Step 9, we quantified q as 19 psf, in Step 7, we determined GCpi to be +/-0.3, and in Step 8, we determined four values for GCpf for four possible roof zones. Table 3 shows the resulting pressures for uplift and downward pressures in each of the roof zones. We calculated uplift using the equation in Step 10 above, and the lowest exterior pressure coefficient (GCpf) provided in the Figures in *ASCE Standard 7-05* for a given roof zone, which is typically a negative number, and the positive interior pressure coefficient (GCpi) from Step 7, above. The negative exterior pressure coefficient represents uplift pressure on the top surface of the PV, and the positive interior pressure coefficient represents pressurization under the module. The combined action of each of these pressure coefficients is to exert an uplift force normal to the PV structure, away from the roof.

Downward pressure is calculated by using the highest exterior pressure coefficient provided in the Figures in *ASCE Standard 7-05* for a given roof zone, and the negative interior pressure coefficient from Step 7. In some cases, the highest exterior pressure coefficient may be a negative number.

Figure 6-10 provides only one exterior pressure coefficient for each roof zone, so the same exterior pressure coefficient is used to calculate the worst-case uplift and downward pressure at each roof location. This is not always the case, so designers should use appropriate Figures in Chapter 6 of the *ASCE Standard 7-05*, applied carefully on a case-by-case basis.

The recommended exterior and interior pressure coefficients and resulting uplift and downward pressures are shown in Table 2.

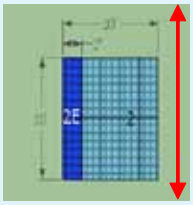
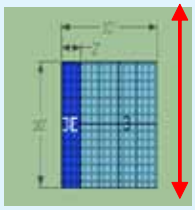
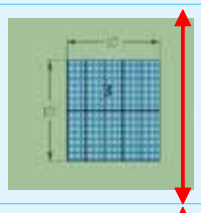
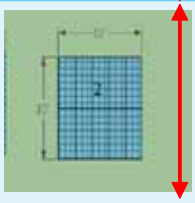
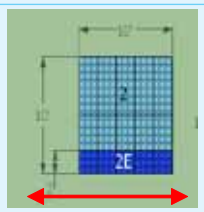
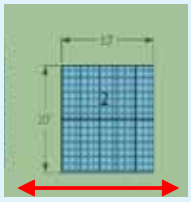
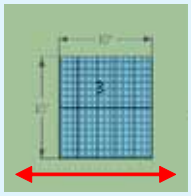
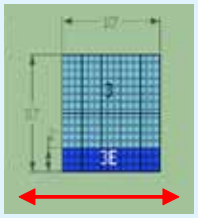
Table 2: Uplift and Downward Pressures for All Roof Locations

Roof Zone	Positive Interior Pressure Coefficient, $+GC_{pi}$ (to calculate uplift pressure)	Negative Interior Pressure Coefficient, $-GC_{pi}$ (to calculate downward pressure)	Exterior Pressure Coefficient, GC_{pf}	Design Wind Uplift Pressure, $p = q*(GC_{pf} - GC_{pi})$	Design Wind Downward Pressure, $p = q*(GC_{pf} - GC_{pi})$
2	0.3	-0.3	-0.69	-18.81	-7.41
3	0.3	-0.3	-0.48	-14.82	-3.42
2E	0.3	-0.3	-1.07	-26.03	-14.63
3E	0.3	-0.3	-0.69	-18.81	-7.41

The results show that downward pressure need not be considered in this case, because all values in the right-most column are negative, indicative of uplift pressures that are lower in magnitude than the design wind uplift pressures in the second to last column. This may not always be the case, so the designer should check for each system design. In this example, we need only consider the design wind uplift pressure values for each of the zones.

A structural engineer would need to consider the uplift and downward loads shown in Table 2 on various sections of the array, depending on the location of the array relative to the four roof zones in each load case. The load cases are summarized in Table 3, below. These load cases should be used to evaluate loads on the PV mounting structure as well as loads on the building resulting from the installation of the PV system.

Table 3: Load Cases for PV Structure, Based on ASCE Figure 6-10

Load Case	Direction of MWFRS[1]	Ref. Corner	Ref. Figure	Array Loading Diagram
1	Transverse	A	Figure 1 A	
2	Transverse	B	Figure 1 B	
3	Transverse	C	Figure 1 C	
4	Transverse	D	Figure 1 D	
5	Longitudinal	A	Figure 2 A	
6	Longitudinal	B	Figure 2 B	
7	Longitudinal	C	Figure 2 C	
8	Longitudinal	D	Figure 2 D	

[2] Reference ASCE Figure 6-10 and the red arrows in the Table 3 column labeled "Array Loading Diagram."

Simplified Approach

A slightly conservative but simpler approach can be used to design the array by simply designing for the worst-case wind loads in any section. From Table 2, it is clear that downward pressure can be neglected, that zone 2 has the highest uplift for interior sections of the array, and zone 2E has the highest uplift for any edge location. This gives the following loading diagram for the sample array, which could be applied to structural members in both the transverse and longitudinal directions:

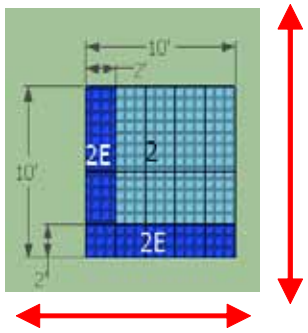


Figure 3. Simplified Conservative loading for the PV mounting structure

Sample Calculation 2

Wind Loads on PV Module, Mounting Clips and Hardware
(Components and Cladding, Section 6.5.12.4)

Location: Phoenix, Arizona
Terrain: Open desert, very few buildings.
Building height: 17'3" at the eave, 22'9" at the ridge
Building shape: Gable roof with a 20° pitch
Building type: Residential
Building dimensions: 60' (along the ridge) x 30' (perpendicular to the ridge)
Module orientation: Parallel to roof, 5" above roof surface, 4 ft from the roof edge.
PV module area: 2' x 5'

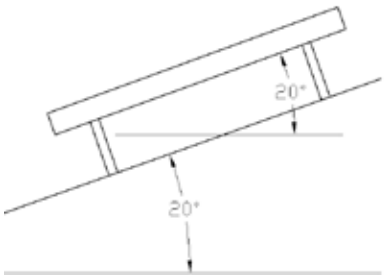


Figure 4. Array mounted parallel to the roof slope

Steps:

1. Reference Figure 6-1 to determine the basic wind speed for the Phoenix, Arizona, location. From this Figure, the wind speed is **V = 90 mph**.
2. Reference Section 6.5.6.3 to determine the surface roughness category. Do a physical site inspection or review photographs of the surrounding terrain in all directions to properly classify the surrounding terrain using the definitions in this section. If the terrain varies in the upwind direction or if the location is in a transitional zone, use the worst-case wind loads. For this sample problem, we assumed that Exposure C applies for this open desert location.
3. Determine the occupancy category using Table 1-1. In this case, it is **Type II** for a residential building.

4. Determine the importance factor using Table 6-1. In this case, **I = 1.00** for a Type II building.

5. Reference Section 6.5.7.1 to determine the topographic factor, K_{zt}. For this sample calculation, we will assume that the site is on level terrain, so **K_{zt} = 1.0.**

6. Determine a velocity pressure exposure coefficient using Table 6-3. As discussed in the definition of the height (h) in Section 6.3, use the mean roof height (note that eave height is used for a roof pitch < 10°). The mean height in this case is 20 feet. For an exposure terrain classification of C, and a roof height of 20, we obtain a velocity pressure exposure coefficient of **K_z = 0.90.**

7. Determine enclosure classification and internal pressure coefficients. As we discussed in the preceding Sample Calculation 1, Step 7, the recommended value for GCpi is +/- 0.1 to +/- 0.3. In this example, we used +/- 0.3.

8. Determine the external pressure coefficient. Compare the building height and shape to those shown in Figures 6-11B – D, 6-12, 6-13, 6-14A-B, 6-15, 6-16, 6-17, 6-18A-D, and 6-19A-C in *ASCE Standard 7-05*. Note that Figures 6-18 and higher are for "free roofs," or buildings without walls (see formal definition in Section 6.2). In this example, the building has a gable roof with a 20-degree slope, and the left side of Figure 6-11C is a good match. Figure 6-11C shows three roof zones, representing interior (zone 1), edge (zone 2), and corner (zone 3) locations on the roof.

   Section 6.2 defines the effective wind area, but it is slightly ambiguous. We recommend that the designer use the area of the PV module to calculate wind loads on the PV itself. However, for determining loads on fasteners, the effective wind area should be the fraction of the PV module that is secured by the fastener.

   For example, in many arrays, fasteners are placed at third points (points one-third of the way in from either end) along the long sides of a module, as shown in Figure 5. This figure shows that fasteners in interior regions of the array are used to secure adjacent modules, so that modules are sharing fasteners. The result of this configuration is that fasteners along the perimeter of the array, such as Fastener 1 in the figure, are supporting an effective wind area equivalent to one-quarter of the module area (Area 1 in the figure). Fasteners in interior regions, such as Fastener 2, are supporting an effective wind area equivalent to one-half of the module area (Area 2 in the Figure). In most cases, the same fasteners and clips are used in all locations, so we chose the worst-case configuration. Pressure coefficients become more extreme as the effective wind area becomes smaller.

   To select the worst-case pressure coefficients for fastener design in this example, the designer should use the smallest effective wind area per fastener, equal to one-quarter of the module area of 10 square feet. In this case, the pressure coefficients are the same for an effective wind area between 1 and 10 square feet, so the same pressure coefficients would be used for all fasteners and PV modules. Note that this may not always be the case, depending on the PV module size as well as the roof geometry, which may require that the designer use a figure other than Figure 6-11C. From Figure 6-11C (left-hand of the figure for a gable roof), we obtained following coefficients:

Table 4: Exterior Pressure Coefficients for Sample Calculation 2

Roof Zone	+GCp	-GCp
1	0.5	-0.9
2	0.5	-1.7
3	0.5	-2.6

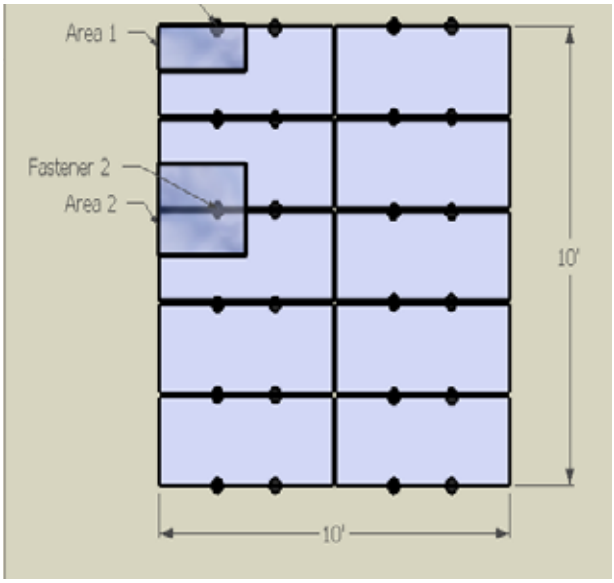


Figure 5. Array layout showing fastener locations and areas tributary to perimeter fasteners versus interior fasteners.

9. Calculate velocity pressure as described in Section 6.5.10:

   q = 0.00256*Kz*Kzt*Kd*V2*I (in psf)

   q = 0.00256*0.92*1*1*902*1 = 19 psf

10. Determine the design wind pressure as described in Section 6.5.12.2.1:

   p = q*GCp – Gcpi

Table 5 summarizes the resulting design uplift and downward wind pressures for each of the three wind zones:

Table 5. Design Wind Uplift and Downward Pressures for Sample Calculation 2

Roof Zone	Positive Interior Pressure Coefficient, $+GC_{pi}$ (to calculate uplift pressure)	Negative Interior Pressure Coefficient, $-GC_{pi}$ (to calculate downward pressure)	$+GC_{p}$	$-GC_{pi}$	Design Wind Uplift Pressure, p= $q*(GC_{pf} - GC_{pi})$	Design Wind Downward Pressure, p= $q*(GC_{pf} - GC_{pi})$
2	0.3	-0.3	0.5	-0.9	-22.8	15.2
3	0.3	-0.3	0.5	-1.7	-38	15.2
2E	0.3	-0.3	0.5	-2.6	-55.1	15.2

Note that in ASCE Figure 6-11 C, a dimension 'a' defines the boundaries of the various roof zones, exactly as it was in Sample Calculation 1, in which we used Figure 6-10. The definition of 'a' in both figures is the same, so the prior result of a = 3 is valid for this calculation. Note that the edge zones in Figure 6-10 were defined by a dimension of 2*a, but in ASCE Figure 6-11 C, a dimension of 1*a defines the edge and corner zones. Zone 2 occupies the parts of the roof between the edges and three feet to the interior, with the exception of the corners. Zone 3 is the corner region, defined as three feet from two adjacent edges of the building. Figure 1 A-D and Figure 2 A-D show that the array is located four feet from the building edge, so Zone 1 is the only loading case that need be considered when calculating wind loads on PV modules or mounting fasteners. This is fortunate, because some modules are not approved for Zone 3's expected wind uplift pressure of 55 psf. This serves as an important reminder to designers to place PV systems as far from the building edge as possible. For the design of the modules and fasteners in this sample PV system, the designer should use an uplift pressure of about 23 psf and downward pressure of about 15 psf.

Conclusions

Although permitting agencies require assessments of the structural attachment of solar equipment to rooftops, the safety and sufficiency of these attachments are not adequately addressed in any codes or standards. It is important to evaluate equipment and attachment methods to ensure that PV equipment will remain attached to structures during windstorm events, and that additional loads or load concentrations do not exceed the structural capacity of the building. *ASCE Standard-7.05* is the standard for wind forces on structures, but it does not provide adequate guidance to the design professionals and code officials tasked with assessing PV installations.

This lack of guidance creates obstacles for the PV industry. The resulting problems include frustrated installers, unhappy customers, and wind-related structural failures. In addition, uncertainty about what constitutes a safe and secure installation for a given wind load can slow or even stop the approval process for PV installations and complicates the training of code officials.

PV modules and arrays present a unique design challenge in high wind regions. Eventually, codes and standards will specifically address the mounting of PV arrays to rooftops to eliminate potential barriers to market development in high wind regions.

In the meantime, this report provides design guidance, including sample calculations for determining the wind loads on PV arrays based on the recognized *ASCE Standard 7-05*. Although this does not specifically address the problem, it is the best option available at this time. The basic guidance for applying the existing codes and standards provided in this report is for the typical residential application of PV arrays mounted parallel to the roof slope and relatively close (3 to 6 inches) to the roof surface. We do not address other array configurations.

It will require much more work to gather information and develop standards specific to wind loading on rooftop PV installations. Although the information in this report does not completely solve the problem, it does provide initial guidance to designers and code officials.

It is important that design professionals read and understand the appropriate codes and standards when designing rooftop PV systems. The guidance presented here is not meant to be a substitute for following the codes and standards. It is also important to for design professionals to stay current with these publications, because we expect the body of information about designing PV systems to withstand local wind loading to grow rapidly in the near future

Recommendations

1. At present, we recommend basing the structural design of roof-mounted PV systems on the *ASCE Standard 7-05* as follows:
   a. Section 6.5.12.2, MWFRS, is the recommended starting point for designing the PV mounting structure, with the PV module oriented above and parallel to the roof surface.
   b. Section 6.5.12.4.1 addresses wind loads on components and cladding. We recommend the use of Section 6.5.12.4.1 and supporting figures only for the design of the PV module attachment clips and hardware to the structure, and for calculating loads on individual PV modules.
   c. We do not recommend Section 6.5.15, 6.5.15.1, and Figure 6-21 for the design of PV systems.
   d. This report provides basic guidance for applying *ASCE Standard 7-05* to existing codes and standards for the typical residential application of PV arrays mounted parallel to the roof slope and relatively close (3 to 6 inches) to the roof surface.

2. Wind tunnel testing for the most common rooftop PV installations should be conducted to verify methods and calculations. The installation types include stand-off mounting parallel to the roof, stand-off mounting at an incline relative to the roof, and ballasted installations on flat roofs. Wind tunnel testing is an important and critical tool that is required to gain a true understanding of pressure equalization, dynamic loads on the modules, interactions with airflow around the building, and transmission of loads to the structure. As we discussed in this report, wind tunnel testing would likely demonstrate significantly lower wind loads for stand-off mounted PV systems parallel to the roof than those predicted by the ASCE standard. When we have a fundamental understanding of the wind forces for basic configurations, we can develop more sophisticated numeric models to evaluate other geometries. These models can simplify and add confidence to the design process. When we have a more complete understanding of the fluid mechanics involved, we can accurately determine the forces on the equipment and structural attachments. With more confidence in the actual wind forces on roof-mounted PV arrays, the codes and standards can be updated to provide accurate design guidelines.

3. We recommend that codes and standards be modified to specifically address the mounting of PV arrays to rooftops to eliminate potential barriers to market development in high wind regions. Recommended changes should be based on the wind tunnel testing in Recommendation 2.

4. We recommend that local jurisdictions and design professionals use the recommendations in this report to ensure continuity in interpreting existing codes and standards.

References

American Society of Civil Engineers (ASCE) (2006), *Minimum Design Loads for Buildings and Other Structures* (7-05).

Acronyms

AHJ	authority having jurisdiction
ASCE	American Society of Civil Engineers
IBC	International Building Code
MWFRS	main wind-force resisting system
PV	photovoltaics

Glossary

Components and cladding— element of the building that does not qualify as the MWFRS. (ASCE definition)

MWFRS—an assemblage of structural elements assigned to provide support and stability for the overall structure. The system generally receives wind loading from more than one surface. (ASCE definition)

Solar America Board for Codes and Standards

www.solarabcs.org

Solar ABCs Policy Recommendation:

Module Power Rating Requirements

Prepared by

Govindasamy TamizhMani
Arizona State University
Photovoltaic Reliability Laboratory (PRL)

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March 2011

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Solar America Board for Codes and Standards

The Solar America Board for Codes and Standards (Solar ABCs) is a collaborative effort among experts to formally gather and prioritize input from the broad spectrum of solar photovoltaic stakeholders including policy makers, manufacturers, installers, and consumers resulting in coordinated recommendations to codes and standards making bodies for existing and new solar technologies. The U.S. Department of Energy funds Solar ABCs as part of its commitment to facilitate widespread adoption of safe, reliable, and cost-effective solar technologies.

For more information, visit Solar ABC's website:
www.solarbcs.org

Acknowledgements

This material is based upon work supported by the U.S. Department of Energy under Award Number DE-FC36-07GO17034.

TABLE OF CONTENTS

DISCLAIMER ii

AUTHOR BIOGRAPHIES iii

SOLAR AMERICA BOARD FOR CODES AND STANDARDS iii

ACKNOWLEDGEMENTS iii

POLICY STATEMENT 1

- Objective 1
- Goals 1
- Audience for Policy 1
- Scope and Limitation of Policy 1
- Motivation for Policy 1
- Solar ABCs Policy Recommendation 2

POLICY JUSTIFICATION 3

- Past Issues 3
- Present Evidence 4

REFERENCES 6

APPENDIX 7

POLICY STATEMENT

Objective:

Develop a Solar America Board for Codes and Standards (Solar ABCs) power rating policy statement that establishes requirements for the procurement of photovoltaic (PV) modules for consumers, states, and organizations providing incentives for PV systems in the United States.

Goals:

The goals of this policy statement are to:

- increase customer awareness of the potential for discrepancy between the name-plate rating and performance of delivered PV modules and define a reasonable expectation for the consistency of these numbers;
- increase customer awareness of the power ratings available to them as a result of the IEC 61853-1 standard and empower customers to better compare the performance of modules under a range of conditions;
- improve the willingness of financial institutions to lend money for PV systems and reduce the risk of investments in PV systems by tightening the tolerance on module ratings.

Audience for policy:

Stakeholders involved in manufacturing, purchasing, financing, or providing incentives for PV modules and systems.

Scope and limitation of policy:

Solar ABCs will continue to recommend policies that address consumer and industry concerns related to the use of various performance, qualification, and safety standards. The power rating policy is a living document, and its scope is influenced by market requirements and the availability of existing standards. This recommended policy is written in conformity with the performance conditions in IEC 61853-1 standard titled *"Photovoltaic (PV) module performance testing and energy rating – Part 1: Irradiance and temperature performance measurements and power rating."*

Motivation for policy:

Without a power rating tolerance policy, some PV modules may continue to have a significantly lower power output than the module's rating indicates. This results in reduced performance of installed PV systems that will not meet consumers' expectations. If overrating of modules continues, it will jeopardize the credibility of PV performance predictions with the general population and could slow progress toward wide adoption of solar energy technologies. This policy is the same as the existing standard used in Europe (EN 50380) with the addition of a specific lower/upper limit for the production tolerance and removing uncertainty on measured power as it varies from one lab to the other and from one test/reference technology to the other. In addition, without power rating data at various low/high irradiance and temperature conditions, the energy collection predictions for installed PV modules and systems will not be accurate.

Solar ABCs Policy Recommendation:

"It is recommended that photovoltaic module types sold or installed in the United States be independently measured and certified to the following power rating tolerance: after accounting for the light induced degradation[1] as per IEC 61215 (crystalline silicon) or IEC 61646 (thin film), the measured average[2] power shall be equal to or higher than the nominal nameplate power rating at STC (standard test conditions) and no individual module power shall be more than 3% below nominal. In addition, the modules shall be rated at a minimum at the four other reference conditions given in IEC 61853-1 standard: 200 W/m² & 25°C cell temperature; 500 W/m² & 15°C cell temperature; 1000 W/m² & 75°C cell temperature; 800 W/m² & 20°C ambient temperature."

Notes:

1. Values shall be measured after preconditioning according to IEC Standard 61215, Section 5, or after light-soaking according to IEC Standard 61646, Section 10.19. Other stabilizing methods may be utilized as recommended by the manufacturer if they are consistent with outdoor operation.

2. The required number of samples (n) for the average is dictated by the standard deviation (σ) of the measured values. A baseline value for σ is calculated from a minimum number of 30 samples. Then this baseline value of σ is used to determine the required number of samples (n) to meet the Policy recommendation. The required number of samples "n" shall be determined using the following method:

   - Note down the nameplate rated power (P_0 in watts).
   - Measure the individual power of 30 modules.
   - Calculate the standard deviation (σ in watts) of these 30 modules.
   - Determine the sample size "n" using the following equation and table:

$$n = (z_{\sigma/2} * \sigma/0.03P_0)^2$$

Desired Confidence Level	$z_{\sigma/2}$
90%	1.645
95%	1.96
99%	2.58
99.9%	3.3

If the "n" value is determined to be higher than 30, then the measured average power shall be based on "n" samples. If the "n' value is determined to be less than 30, then the measured average power shall be based on 30 samples. The "n" value shall be rounded upward. The details on the sample size determination are presented in the appendix. The timeline for module sampling shall be mutually agreed upon between the supplier and customer.

The measurement uncertainty of each test sample at STC along with calibration traceability chain for the measuring equipment and calibrated modules shall be reported. The independent measurements shall be carried out by an ISO 17025 accredited laboratory acceptable to the customer.

POLICY JUSTIFICATION

Past Issues:

Most consumers, system integrators, and agencies providing incentives have relied on the module nameplate ratings to estimate the power and/or energy delivered by installed PV systems. Unfortunately, those estimations often have not met expectations. A possible outcome of this common trend of overstating module power ratings may be a loss of consumer and government confidence in the ability of PV modules and systems to perform as expected. It is important to recognize that the credibility of PV technology depends not only on the quality of the PV products, but also on industry practices. The nominal power ratings listed on the nameplates of PV modules were often found by independent test laboratories to be much higher than the actual measured power. As shown in Figure 1, module testing by the Florida Solar Energy Center indicated that the measured peak power of PV modules in the United States marketplace was typically less than the nameplate value (Atmaram, TamizhMani, & Ventre, 2008). In some cases, the measured power of the modules sourced from the open market was found to be nearly ten percent below the nameplate rating. BEW Engineering reported similar data on installed PV arrays, as illustrated in Figure 2 (Lilly et al., 2006).

In the past, this overrating issue was often attributed to the ANSI/UL 1703 standard (ANSI/UL 1703, 2008, etc.), which states that "the short-circuit current (Isc), rated current (Ir) maximum power (Pmax), and open-circuit voltage (Voc) shall be within ± 10 percent of the rated value." To be clear, the ANSI/UL 1703 standard is a safety standard for PV modules that specifies requirements for the electrical and mechanical safety—it is not a performance or power rating standard—and the use of a safety standard to support the overrating practice is not justifiable.

Initially, a major reason for accepting this wide tolerance was the high measurement reproducibility error among the test labs. But the biggest reason is likely that most modules were used in standalone systems that almost never operated at peak power. The standalone systems were designed to provide power for the worst months of the year, not the best.

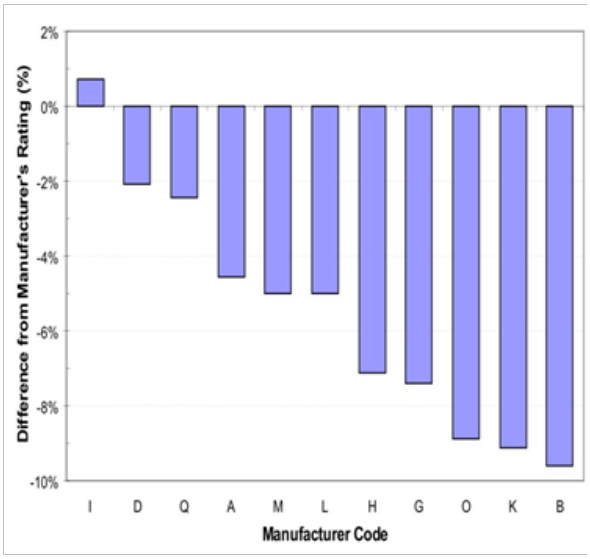

Figure 1: Comparison of measured power with nameplate ratings of modules sourced from open market (Atmaram et al., 2008)

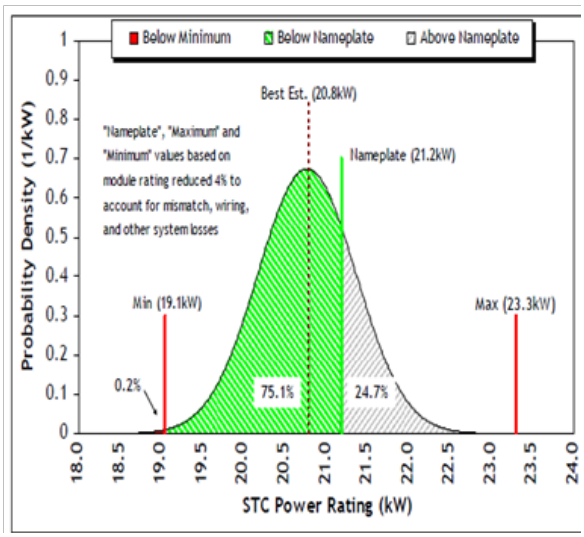

Figure 2: Comparison of the measured power with nameplate ratings of fielded modules (Lilly et al., 2006)

Present Evidence:

Tightening the nameplate power rating tolerance should address the measurement issue related to the reproducibility among test laboratories and the binning/tolerance issue in production lines. Three pieces of objective evidence are presented here—one example to address the first issue and two examples to address the second issue.

Measurement Reproducibility: Every test laboratory has its own inherent uncertainty issues related to measuring the performance of PV modules. These are due to the uncertainties related to the measuring equipment (the I-V curve tracer, for example) and calibration (of the reference cell, for example). The measurement uncertainties vary from one lab to another but they are typically less than 4% for crystalline silicon technologies and as high as 6.5% for thin-film technologies. A major contributor to this module measurement uncertainty is the uncertainty related to reference cell calibration. These uncertainties in turn influence the reproducibility of the results between the test labs. Table 1 indicates that the measurements between a large number of test laboratories can be typically reproduced within about 5% for all the module technologies (Rummel et al., 2006). This indicates great progress by the test/measurement laboratories to tighten measurement uncertainties and improve reproducibility. Measurement uncertainty can be reduced by utilizing reference devices from the same source.

Table 1: Pmax reproducibility between the test/measurement laboratories (% deviation from average)

Reproducibility Tolerance

NREL Round Robin Testing – 2006 (WCPEC4-2006)											
	<Pmax>.W	NREL pre	SNL	ASU	FSEC	ESTI	LEEE	TUV	ISE	JET	NREL post
Mono-Si											
SIE0577	66.84	-2.9	3.2	1.6	-4.2	0.4	-0.2	-0.2	0.8	1.3	-2.6
SIE0586	67.22	-3.2	2.9	1.3	-4.2	0.4	0.6	-0.6	0.7	1.7	-2.8
Thin Film Si											
AsP0123	51.54	-3.5	1.7	0.7		0.9	-1.4	0.3	0.8	-0.6	-2.4
AsP0247	52.87	-3.1	1.8	0.6		1.4	-1.5	0.1	0.6	-0.9	-2.1
a-Si/a-Si/a:Ge											
BPS4213	41.04	4.8	-0.3	2.3		-7.2*		3.3			1.8
BPS4223	36.82	3.7	1.8	3.7		-3.3*		-3.9			1.6
a-Si/a-Si/a-Si											
USSC234	19.24	3.2	-0.6	-0.2		-7.8*		9.1			-0.5
USSC234	19.41	2.7	-0.5	-0.6		-7.2*		8.7			-0.5
CdTe											
BP4405	84.13	0.1	-0.7	4.7		-2.9		-1.0			-0.1
BP4505	87.96	-1 .3	-0.5	4.1		-3.4		-1.0			0.7
CIS											
Sie9257	40.54	-3.3	5.0	3.1		-3.1		-1.3			-3.7
Sie9260	40.10	-3.5	7.6	4.2		-4.7		-3.0			-4.1
Concentrator											
PTEL#1	3.015	3.3	0.8			-3.8					3.0
PTEL#2	2.913	-0.3	3.0			-7.3					4.3

*No special mismatch correction applied.

Production Tolerance: When the industry was producing PV modules at just a few megawatts per year, consumers accepted a wide production tolerance of +/- 10% because of the measurement reproducibility issues, the inherent variations in production lines, and the fact that most modules went to standalone systems where performance variations were not readily apparent. In 2010, the industry produced 18.2 gigawatts of PV modules (SolarBuzz, 2011), and consumers, especially in Europe, have tightened their procurement specifications including the power rating tolerance requirement. In response to increased consumer expectations, all the major manufacturers serving the European market have tightened their nameplate specifications to meet the requirement of the EN 50380 standard (EN 50380, 2003). The EN standard requirement can be presented as the following equation, where "m" is the measurement uncertainty and "t" is the production tolerance.

$$(P_{measured} + m) \geq (P_{rated} - t)$$

The EN standard allows leniency on both sides of the equation: the production tolerance leniency on the right side of the equation and the measurement uncertainty leniency on the left side of the equation. Unfortunately, the measurement uncertainty varies from one lab to another, and one technology to another. Also, the EN standard does not impose any specific lower/upper limit for the production tolerance. Many manufacturers offer data sheets meeting the requirements of the EN standard as shown below. The sampling of major manufactures' data sheets from the Web during 2010 clearly indicates that the manufacturers now have better quality assurance practices (due to improved sorting and better measurement accuracy) and are able to tighten the production tolerances to +/- 3%.

Manufacturer # 1
- Production tolerance = +/- 3%
- The datasheet complies with the requirements of EN 50380 (EN 50380, 2003)

Manufacturer # 2
- Production tolerance = +/- 3%
- The datasheet complies with the requirements of EN 50380

Manufacturer # 3
- Production tolerance = +/- 3%
- No indication of the datasheet complying with the requirements of EN 50380

Manufacturer # 4
- Production tolerance = -5% and +10%
- No indication of the datasheet complying with the requirements of EN 50380

Manufacturer # 5
- Production tolerance = -0% and +5%
- No indication of the datasheet complying with the requirements of EN 50380 but it indirectly complies with EN 50380 as the negative tolerance is 0%

Figure 3 compares the nameplate ratings with the independently measured values of 9,422 modules sold for power plant applications in Europe (Vaassen, 2010). This figure clearly indicates that less than 0.7% of these modules have measured values of less than -3% of the nameplate rated values. Well over 50% of all modules in the study exceeded their rated nameplate power. Again, this confirms that the manufacturers now have better quality assurance practices that allow them to maintain nearly 100% of the production modules above the -3% tolerance limit. Therefore, the Solar ABCs policy has been

designed based on the following two equations, where $P_{measured\text{-}average}$ is the measured average power of "n" samples and $P_{measured\text{-}individual}$ is the measured power of individual samples.

$$P_{measured\text{-}average} \geq P_{rated}$$

&

$$P_{measured\text{-}individual} \geq (P_{rated} - 3\,\%\ \text{tolerance})$$

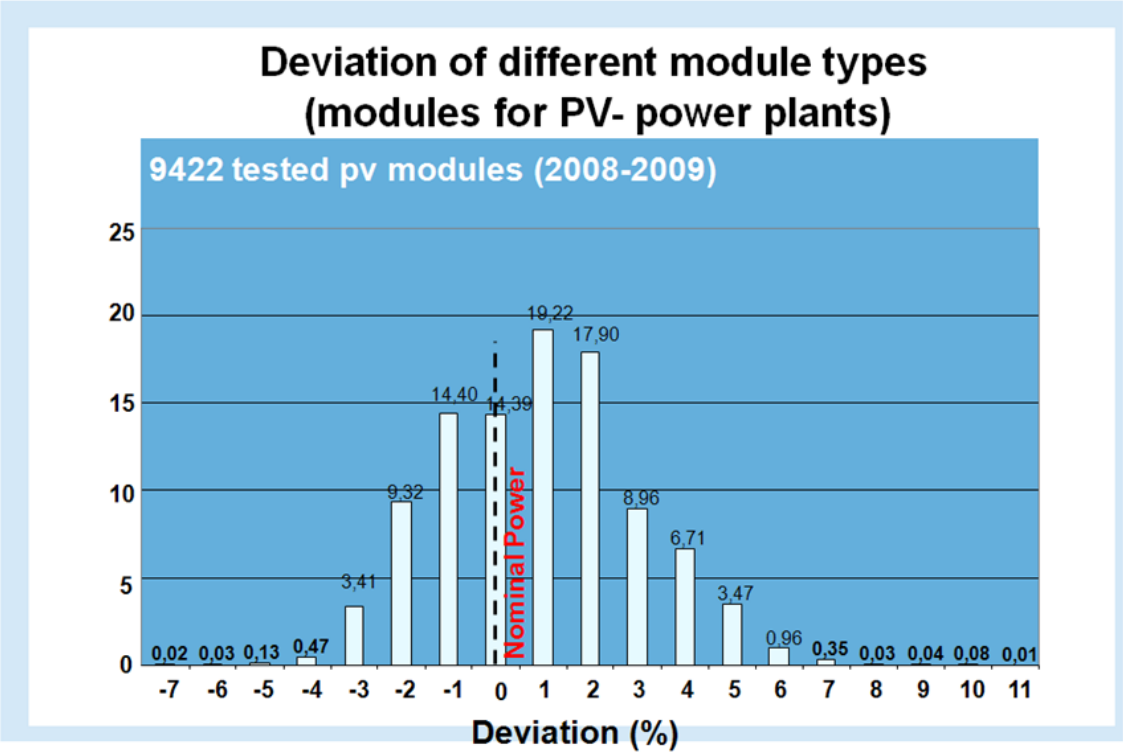

Figure 3: Comparison of the measured power with nameplate ratings of power plant modules (Vaassen, 2010)

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APPENDIX

Sample size (n) determination (J. Kuitche, Arizona State University, personal communication January 2011)

Let's assume we want the measured average power of "n" samples (say, P_r) to be within +/- 3% of the rated value (say, P_0). That is, if we draw a random sample (for example 30 modules) from a production line and compute the average or mean of 30 samples (say, P), then that value (average) shall fall between $0.97P_0$ and $1.03P_0$; with a certain degree of confidence.

We can set our sights on a 95% (2-sigma) or 99% (3-sigma) confidence level, for example. So a 95% confidence interval can be computed as $P_r \pm 2\sigma_P$, where:

$\sigma_P = \sigma/\sqrt{n}$ = standard error of the mean

σ = standard deviation of the sample drawn (30 samples)

n = sample size

Thus, the half-width confidence interval is given by:

$$w = 2 * \sigma/\sqrt{n}$$

More accurately, 95% confidence level <--> $z_{\alpha/2}$ -sigma; so:

$$w = z_{\alpha/2} * \sigma/\sqrt{n}$$

where $z_{\alpha/2}$ can be obtained from statistical tables for any confidence level.
The commonly used values of $z_{\alpha/2}$ are shown in the following table:

Desired Confidence Level	$z_{\sigma/2}$
90%	1.645
95%	1.96
99%	2.58
99.9%	3.3

If the target half-width is 3% P_0 as stated, then:

$$3\%P_0 = z_{\alpha/2} * \sigma/\sqrt{n}$$

$$n = (z_{\alpha/2} * \sigma/0.03P0)^2$$

Notes:

The value of "σ" is estimated from a prior sample (of size 30 above).
The value of "n" obtained shall be rounded upward.
P_r is the average of "n" samples after accounting for the light induced degradation.

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Download a copy of the report:
www.solarabcs.org/cellprocurement

Executive Summary

This study report documents the need for a supply chain procurement specification and standard that applies to photovoltaic (PV) cells. Many PV module manufacturers depend on third party solar cell manufacturers for their supply of silicon cells. Each individual module manufacturer currently develops and uses their own cell procurement specification. No common, baseline procurement specification exists for use by the entire industry.

This study report presents a proposed standard with thorough explanations and justifications for each section of the standard. This proposed standard, entitled "Crystalline Silicon Terrestrial Photovoltaic Cells – Supply Chain Procurement Specification Guideline" follows the format of the ASTM but can be easily adapted to formats of other standard making bodies such as SEMI, IEEE and IEC.

This study report recommends that the content of the proposed standard serve as the starting point for a thorough discussion of this topic by appropriate standards making bodies. Comments from stakeholders, especially the cell and module manufacturers who will most benefit from this work, are particularly invited. The report closes with recommendations for additional supply-chain specification standards related to PV module manufacture including encapsulant, backsheet, junction box, cables, glass superstrate, and framing materials.

Author Biography

Dr. Govindasamy (Mani) TamizhMani is the president of TUV Rheinland PTL (Photovoltaic Testing Laboratory) and a professor in the Department of Electronic Systems at Arizona State University. Dr. Mani has been involved in R&D activities related to photovoltaics and fuel cells for over 25 years and photovoltaic module testing and certification activities for over 10 years. He has been involved in test standards' development activities since 1996. He has served or has been serving as a member of various standards committees including Canadian Standards Council, IEEE, IEC and ASTM. He has taught graduate level courses related to photovoltaics, fuel cells, electrolysis and batteries, has published more than 50 journal and conference papers, and has served as a reviewer of numerous conference and journal publications including IEEE Photovoltaic Specialists Conference, *Progress in Photovoltaics and Journal of the Electrochemical Society.*

Solar America Board for Codes and Standards

The Solar America Board for Codes and Standards (Solar ABCs) is a collaborative effort among experts to formally gather and prioritize input from the broad spectrum of solar photovoltaic stakeholders including policy makers, manufacturers, installers, and consumers resulting in coordinated recommendations to codes and standards making bodies for existing and new solar technologies. The U.S. Department of Energy funds Solar ABCs as part of its commitment to facilitate wide-spread adoption of safe, reliable, and cost-effective solar technologies.

For more information, visit the Solar ABCs Web site:
www.solarabcs.org

Acknowledgements:

This material is based upon work supported by the Department of Energy under Award Number DE-FC36-07GO17034.

Table of Contents

Disclaimer ii

Executive Summary iii

Author Biography iv

Introduction 1

Background and Issue 1

Purpose of each section of the proposed standard 1

Conclusions 3

Recommendations 3

Proposed standard 4

1. Scope 4

2. Packing, marking, and storage 4

3. Process and wafer characteristics and module package-ability 5

3.1 Process characteristics 5

3.1.1 Adhesion strength 5

3.1.2 Solder connection 5

3.2 Wafer characteristics 5

3.3 Module package-ability 6

4. Cell characteristics 6

4.1 Non-performance characteristics 6

4.2 Performance characteristics 8

5. Declaration letter for modification 9

6. Documentation 10

References 11

Introduction

Background and Issue

A large number of photovoltaic (PV) standards have been developed for modules and systems by the technical committees of various standards organizations, including ASTM (E44-09), IEEE (SCC21) and IEC (TC82). Only very few industry standards, however, have been developed for issues related to individual solar cells. Cell-level standards, developed thus far have been limited to those that deal only with performance-measurements issues. They exclude issues faced by the module manufacturers during the stages of procurement of cells from the cell manufacturers and production of modules based on the procured cells.

Almost all the modules that are sold in any part of the world have to meet the design qualification requirements of the module standards [IEC 61215: Crystalline silicon terrestrial photovoltaic (PV) modules – Design qualification and type approval; IEC 61646: Thin-film terrestrial photovoltaic (PV) modules - Design qualification and type approval]. In order to qualify the entry of these modules in the marketplace, these module standards call for severe environmental, electrical, and mechanical stress tests. In addition, practically every module manufacturer provides a warranty exceeding 20 years, which makes it imperative for them to ensure that their modules work for decades to come. The cells are the heart of every PV module. If the cells fail, the entire module fails. Recent failure-rate analysis conducted by Arizona State University (ASU) Photovoltaic Testing Laboratory indicates that a large portion of the accelerated module qualification failures are related to the failure of the cell itself [IEEE Photovoltaic Specialists Conference, San Diego, May 2008]. Based on field failures as a percentage of the total number of failures observed from 1994 through 2005 at BP Solar and Solarex, BP Solar reported about 86% of the field failures are corrosion or breakage of cell or cell-related components [SPIE Solar Energy Conference, San Diego, August 2008]. In this Solar ABCs study, effort has been made to initiate developing a cell prequalification specification standard for the benefits of module as well as cell manufacturers.

Purpose of each section of the proposed standard:

The proposed potential standard, entitled "Crystalline Silicon Terrestrial Photovoltaic Cells –Supply Chain Prequalification Specification," is presented in part two of this document. The general format of ASTM standards has been used as the basis for the proposed standard. It would be a simple editorial process to convert this format to another format of other standards, such as IEEE and IEC. The content presented in this proposed standard is based on industry's need for the development of procurement specification for solar cells. The content presented in each section of this standard intends to meet the expectation of the module manufacturers so they can use this standard to develop their own procurement specifications. In the following paragraphs, the purpose of each section is explained so that the reader is informed of the necessity of each section.

Purpose of section 1: Scope

Because a large number of module manufacturers depend on the cell manufacturers for their cell supply, the individual manufacturers use their own procurement specifications. The proposed standard aims to develop a standardized specification so that the entire industry could benefit from using a common, baseline procurement specification. This section, scope, provides the scope and limitation of the proposed standard.

Purpose of section 2: Referenced documents

The documents provided in this section were used to develop most of the proposed standard. Few standards are available because they are specific to the dimensional and other key characteristics of a PV cell. This standard, therefore, references a large number of SEMI standards that are related to silicon wafers used in the electronic industry rather than the solar industry. These references will need to be changed when the solar industry develops its own standards for PV cells.

Purpose of section 3: Packing, marking, and storage

Because wafer-based PV cells are fragile and sensitive to storage conditions, this section provides requirements for meeting the baseline packing, labeling, and storage requirements. These requirements are very similar to the requirements used by the electronic industry.

Purpose of section 4: Process and wafer characteristics

Reliability of the modules and the system depend on the core element: the solar cell itself. The failure modes and mechanisms of the solar cells heavily depend on the materials and processes involved in making the solar cells. The wafer properties and cell processing methods including the adhesion of the metallic layers and solder connection heavily influence the final characteristics of the PV cells. As reported by the electronic industry, such as Jet Propulsion Laboratory in 1980s, reliability workshops in 1990s, and other technical and scientific literature, solder compositions and soldering conditions—including solder temperature, solder time and soldering pressure—heavily influence the reliability of the PV cells (and hence the modules and the system) in field conditions. This section identifies the required process and wafer characteristics to meet the intent of this standard.

Purpose of section 5: Cell characteristics

This section is composed of two sub-sections: non-performance characteristics and performance characteristics. Non-performance characteristics include visual, dimensional, physical, chemical, electrical, and mechanical parameters. Performance characteristics include various performance parameters, such as short-circuit current, open-circuit voltage, maximum power, temperature coefficients, measurement tolerance and production tolerance at the standard test conditions. This section also includes the required performance parameters at a low light level because they are required in the module qualification standards such as IEC 61215.

Purpose of section 6: Declaration letter for modification

The entire PV industry has successfully followed the module-retest guideline for over 11 years. Any change in the cell characteristics, module design, materials, components, or processing of the module may require a repetition of some or all of the qualification tests to maintain type approval per IEC 61215. Specifically, the module-retest guideline calls for an extensive retest if any significant cell modifications are declared by the module manufacturers. For the module retesting, the module manufacturers are required to submit a “Similarity Declaration Form” so that the test laboratories can determine which additional tests are required to maintain the type approval certificate per IEC 61215. In the proposed standard, a similar approach is recommended for the specification modification of the PV cells. This document proposes to require a declaration from the cell manufacturers, before each shipment, to identify the significant modifications to the cell so that the module manufacturers could make an appropriate procurement decision.

Purpose of section 7: Documentation

The documentation is a certified compilation of all the datasheets and process sheets generated as per all other sections of this document. It is proposed to include the requirement of a certificate of conformity confirming full compliance with the specifications of this standard.

Conclusions

- In this study, a proposed content for a potential standard entitled "Crystalline Silicon Terrestrial Photovoltaic Cells –Supply Chain Procurement Specification Guideline" has been developed and presented. The purpose of each section in the proposed standard is explained.
- For the dimensional and other key characterizations of a solar cell, due to the absence of dedicated cell characterization standards, the proposed standard relies on and refers to several silicon wafer standards (SEMI standards developed for the electronic industry). There is a need to develop dedicated standards specific to solar cells and solar cell wafers so that both cell and module manufacturers can use them for the development / procurement of solar cells. All the referenced electronic industry specific SEMI standards may need to be replaced with the to-be-developed solar cell specific standards.

Recommendations

- To make the proposed content/standard a consensus standard, a thorough discussion on the format and content of the proposed content/standard will need to be carried out by a standards committee from IEEE, ASTM, SEMI or IEC.
- To improve the proposed/content of the standard, comments from the stakeholders, especially the supply/procurement specifications used by the cell/module manufacturers, are requested.
- The development of additional supply-chain procurement specification standards for other module components, such as encapsulant, backsheet, junction box, glass superstrate, frame material and cables, are recommended.

PROPOSED STANDARD

IEEE/IEC/ASTM/SEMI Designation: XXXXXX-08

Crystalline Silicon Terrestrial Photovoltaic Cells – Supply-Chain Procurement Specification

1. Scope

1.1 This standard provides the minimum required information to prequalify the photovoltaic (PV) cells that would assist the module manufacturers in identifying suitable alternative sources for establishing the supply chain.

1.2 This standard applies only to wafer-based crystalline silicon solar cells. A separate standard for thin-film cells will be established in the future.

1.3 This standard does not apply to cells used with concentrated sunlight (higher than 3X).

The intent of this standard is to identify the minimum cell procurement specifications that could be used by the module manufacturers to design and construct modules capable of passing the qualification of photovoltaic modules as defined in IEC 61215 and IEC 61730-2 and of withstanding prolonged exposure in typical climates. The actual lifetime expectancy of modules containing the cells procured using this standard will depend on the cell characteristics, design/packaging characteristics, their environment, and the conditions under which they are operated.

1.4 The minimum procurement information of PV cells includes sampling, packing, marking and storage procedures; process and wafer characteristics; cell characteristics (dimensional, visual, electrical, physical and mechanical); module package-ability, a declaration letter to inform the module manufacturers regarding cell process, material or structure modifications, if any; and a documentation including a full report with all the characteristics identified in this standard.

1.5 The module manufacturer may call for additional information to investigate the suitability of the supplied cells in their specified module construction package.

1.7 This standard is not intended to waive or replace any tests or requirements of the qualification standards (such as IEC 61215 and IEC 61730-2) or their retest guidelines.

2. Packing, marking, and storage

The cells shall be accompanied by documentation detailing packing, marking, and storage procedures. Each smallest packing unit shall carry the following clear and indelible markings:

- name, monogram, or symbol of manufacturer;
- cell type (monocrystalline or polycrystalline silicon) and its designation;
- lot number;
- quantity in each pack;
- date and place of manufacture (marked on the package or be traceable from the lot number);
- indication of electrode polarities;
- stacking ability for storage;
- ambient conditions for storage;
- maximum recommended time for storage.

Cells should be packed in such a manner to ensure minimal damage to the product during transportation. As a guideline, the following apply:

- cells should be packed with a specified maximum unit number per pack;
- cells in each pack shall have originated from the wafers of no more than two different ingots;
- packs shall be contained in compartmented, cushioned boxes suitable for shipping and handling;
- outermost container shall bear clearly legible labels stating, for example, “Fragile; Handle with Care”

3. Process characteristics, wafer characteristics and module package-ability

The cells should have been manufactured from specified materials and components in accordance with the relevant drawings and process sheets and subjected to the manufacturer’s normal inspection, quality control, and production-acceptance procedures. All the relevant datasheets and/or product specifications shall be included in the documentation of this supply chain specification. The documentation may contain certified material test report, certificate of conformance, certified electrical measuring record, certificate to quality management, etc.

3.1 Process characteristics

3.1.1 Adhesion strength

The material and composition of all the surface layers for soldering shall be provided along with supporting documentation. The adhesion strength data of all surface layers able to be soldered shall be reported with the tape testing according to IEC 60326-2, test 13a (for example, with the use of 3M 810 tape). The adhesion force shall be between 2 N/cm and 4 N/cm or acceptable to the module manufacturer.

3.1.2 Solder connection

The “solderability” inspection shall be carried out according to EN 60068-2-44. The adhesion strength of solder connection shall be measured using the test method of EN 61189-2 (2M05) or another suitable method acceptable to the module manufacturer. The minimum peel strength shall be 1 N per mm of solder tab width or acceptable to the module manufacturer. The cell supplier shall provide details for suitable solder compositions and soldering conditions including solder temperature solder time and soldering pressure. Any limitation on the soldering method and soldering conditions shall be clearly identified.

3.2 Wafer characteristics

The surface characteristics of the wafers used for the cell fabrication shall be reported. These surface characteristics include visible surface damage, saw damage marks, and stains. All the key characteristics of the wafers used for the cell fabrication shall be reported according to the applicable SEMI standards listed in Annex, which include the following:

- type of silicon ingot (monocrystalline or polycrystalline) used;
- crystal growth technique;
- nominal crystal orientation, if applicable;
- wafer sawing technique;

- conductivity type and dopant;
- nominal resistivity;
- nominal dimensions (thickness, length, width and diameter if pseudo-square size);
- extent of warping;
- bulk structural defects, if any;
- impurity concentration range (interstitial oxygen and substitutional carbon);
- wafer surface preparation process; and
- average carrier lifetime.

3.3 Module package-ability

The package-ability of the cells, in at least one module package, shall be demonstrated by the cell manufacturers through meeting the pass requirements of IEC 61215 and IEC 61730 (part 2) standards.

4. Cell characteristics

All the relevant datasheets and/or product specifications shall be included in the documentation of this supply chain specification. The documentation may contain certified material test report, certificate of conformance, certified electrical measuring record, certificate to quality management, etc.)

4.1 Non-performance characteristics

The non-performance characteristics include visual, dimensional, physical, chemical, electrical and mechanical parameters. As a minimum, the following non-performance characteristics and information shall be reported:

- visual defects of metallization (broken finger, missing busbar print, etc);
- edge defects, visible chips, indents, and stains;
- cracked/broken cells (no cracked or broken cells are allowed at packing);
- color category;
- metallization materials;
- diagrammatic representation of metallization (including busbars) location and dimensions (thickness, length and width) (see Figures 1A and 1B for a sample technical drawing);
- anti-reflective coating material and thickness and whether it is deposited before the metalization or on top of the metalization;
- type top and bottom semiconductor layer materials and thickness;
- type and concentration of dopants of the cell active layers;
- nominal series resistance and low shunt cut-off resistance of the cell;
- dimensions of the cell including cell thickness, length and width with tolerances;
- total thickness variation;
- shape of cell (square, pseudo-square etc.);
- adhesion strength of all surface layers including antireflective coating and

metallization according to IEC 60326-2, test 13a;

- extent of warping according to SEMI MF1390-04;
- concentricity (the distance between the centre of the circle and centre of the square in pseudo-square cells); and
- cell breaking strength (during soldering and stringing; a method to measure breaking strength needs to be developed/defined at the time of actual standard development).

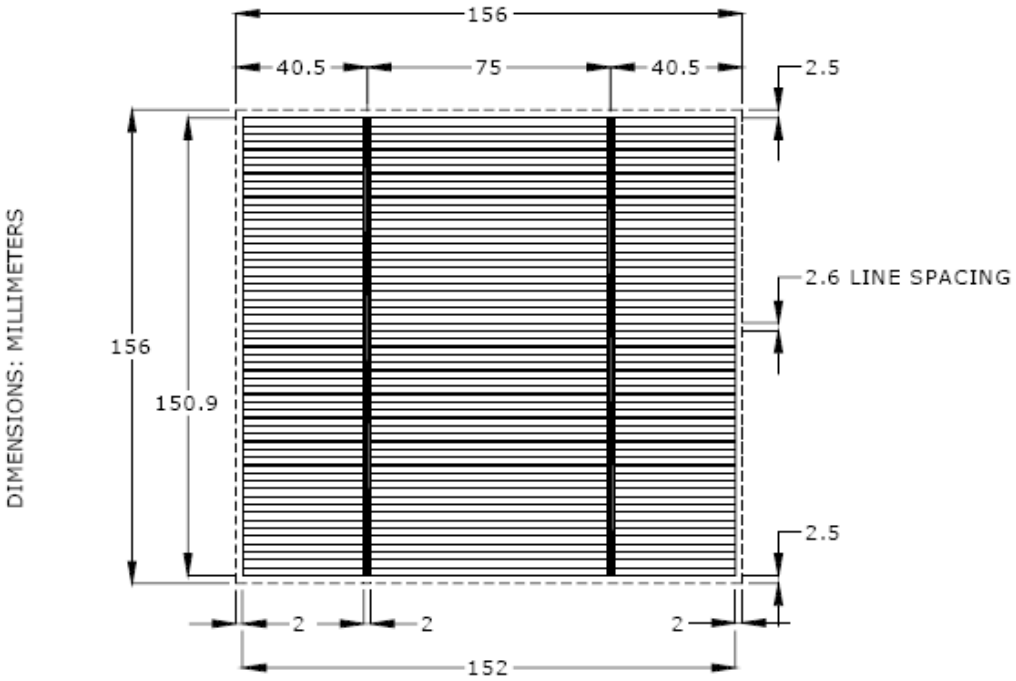

Figure 1 (A): Sample dimensions of the front side metallization of a solar cell [tolerance to be specified]

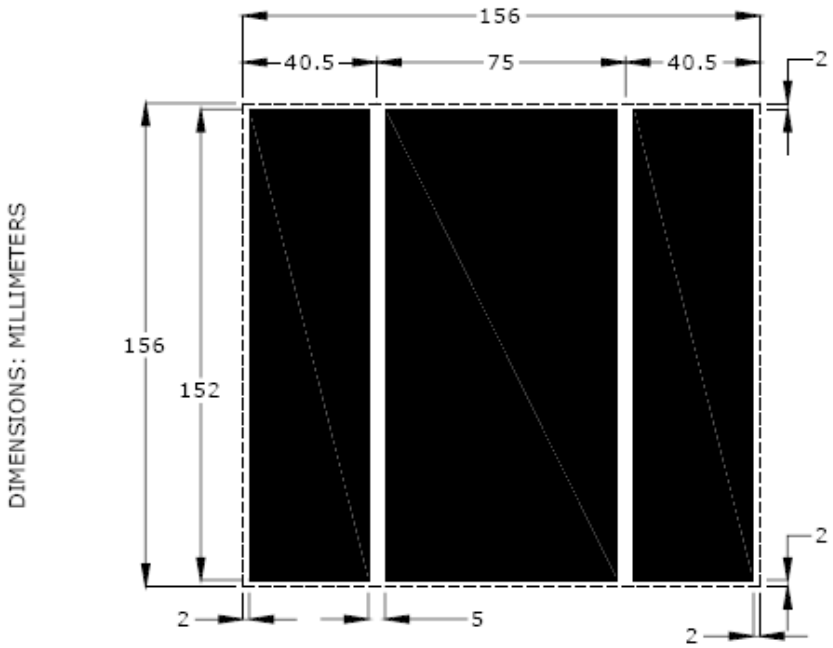

Figure 1 (B): Sample dimensions of the back side metallization of a solar cell [tolerance to be specified]

4.2 Performance characteristics

The performance characteristics at both standard test conditions (STC) and low irradiances shall be reported as shown in Table 1. The STC condition refers to 1000 W/m² irradiance, 25°C cell temperature and AM 1.5G spectrum. The parameters are to be obtained and reported as stabilized after at least 5 kWh/m² light conditioning (to address the light induced degradation, if any). For the low irradiances, the parameters are to be obtained and reported for the AM 1.5G spectrum unless otherwise required.

Table 1. Performance Characteristics of the Solar Cell

Performance Parameter	Symbol (Unit)	Value
Short circuit current @ STC	I_{sc} (A)	
Open circuit voltage @ STC	V_{oc} (V)	
Current at maximum power @ STC	I_{mp} (A)	
Voltage at maximum power @ STC	V_{mp} (V)	
Maximum power @ STC	P_{mp} (W)	
Fill factor @ STC	FF (%)	
Cell efficiency @ STC	(%)	
Cell efficiency tolerance @ STC	(%)	
Production Tolerance @ STC	I_{sc} (%)	
	V_{oc} (%)	
	I_{mp} (%)	
	V_{mp} (%)	
	P_{mp} (%)	
Measurement Tolerance @ STC	I_{sc} (%)	
	V_{oc} (%)	
	I_{mp} (%)	
	V_{mp} (%)	
	P_{mp} (%)	
Temperature Coefficients @ STC	α_{Isc} (%/°C)	
	β_{Voc} (%/°C)	
	β_{Vmp} (%/°C)	
	δ_{Pmp} (%/°C)	
	ε_{FF} (%/°C)	
Short circuit current @ 25°C, 200 W/m²	I_{sc} (A)	
Open circuit voltage @ 25°C, 200 W/m²	V_{oc} (V)	
Current at maximum power @ 25°C, 200 W/m²	I_{mp} (A)	
Voltage at maximum power @ 25°C, 200 W/m²	V_{mp} (V)	
Maximum power @ 25°C, 200 W/m²	P_{mp} (W)	
Fill factor @ 25°C, 200 W/m²	FF (%)	
Cell efficiency @ 25°C, 200 W/m²	(%)	
Reverse breakdown voltage	V	

5. Declaration letter for modifications

Changes in material selection, components, and manufacturing process of the cells can impact electrical performance, safety and reliability of the modules. Significant changes in the structure, materials, components, and/or processing of the cell require a supplier declaration, as these changes may warrant retesting of the modules per module design qualification and type approval standard such as IEC 61215. Significant changes to the cell manufacturing process must be declared to the module manufacturers and agreed upon prior to the modifications being made. This declaration shall be made for every shipment to the module manufacturer. These modifications include, but not limited to the following:

- nominal performance parameters, including cell efficiency, Pmax, Isc, Voc and FF at standard test conditions, and low irradiance;
- metallization materials and/or process;
- anti-reflective coating material and thickness and location in cell structure (before or after metallization);
- change in type of diffusion process;
- semiconductor layer materials;
- order of cell process if the change involves the metallization system;
- change of manufacturing site of the solar cells not under the same QA system;
- supply of cells from a different manufacturer;
- reduction in nominal cell thickness by greater than 25%;
- number of recommended cells per string;
- type and concentration of dopants for the active layers of the cell;
- minimum shunt resistance for cell sorting;
- total thickness variation;
- shape of cell (square, pseudo-square etc.);
- adhesion strength of all surface layers including antireflective coating and metallization, if process changed;
- extent of warping, if process changed;
- visible stains and cracks, if process changed;
- concentricity (the distance between the centre of the circle and centre of the square in pseudo-square cells);
- crystal growth method of the wafers; and
- wafer surface etching materials, composition and process.

6. Documentation

All the relevant datasheets and/or product specifications identified in this standard shall be included in the documentation in accordance with the relevant sections of ISO/IEC 17025. The documentation may contain certified material test report, certificate of conformance, certified electrical measuring record, certificate of quality management etc. The documentation shall include at least the following information:

- a title;
- name and address of the supplier;
- name and address of the test laboratory and location where the tests were carried out, if applicable;
- unique identification of the report and of each page;
- description and identification of the cell;
- packing, marking, and storage procedures as identified in this standard;
- process and wafer characteristics as identified in this standard;
- cell characteristics including physical, electrical, mechanical, and dimensional characteristics as identified in this standard;
- a statement of the estimated tolerance for each of the reported parameter, where relevant;
- a letter of commitment to declare the significant cell modifications;
- date(s) of tests, where relevant;
- identification of test method used, where relevant;
- any deviations from, additions to, or exclusions from this standard, and any other information relevant to a specific to the supplied solar cell;
- measurements, examinations, and derived results supported by tables, graphs, sketches, and photographs as appropriate including temperature coefficients of short-circuit current, open-circuit voltage and peak power, power at standard test conditions and low irradiance per IEC 61215 standard, and a description of data acquisition system (including scan time and current-voltage pair collection procedure, if pulse solar simulator used) and classification of the solar simulator used for the performance measurements;
- All the measurements shall be traceable as per ISO 17025 requirements
- a signature and title, or equivalent identification of the person(s) accepting responsibility for the content of the report, and the date of issue;
- certificate of conformity confirming full compliance with the specifications of this standard.

References

IEC Standards:

IEC 61215 (2005): Crystalline silicon terrestrial photovoltaic (PV) modules-Design qualification and type approval

IEC 60904-1: Photovoltaic devices-Part 1: Measurement of photovoltaic current-voltage characteristics

IEC 60068-2-44: Environmental testing-Part 2: Guidance on tests: Soldering

IEC 61189 series: Test methods for electrical materials, printed boards and other interconnection structures and assemblies

IEC 60326-2, Printed boards-Part 2: Test methods

IEC 61730 (part 2): Photovoltaic (PV) module safety qualification: Requirements for testing

IECEE Retesting Guidelines for design modifications per IEC 61215

EN Standards:

EN 50380 (2003): Datasheet and nameplate information for photovoltaic modules

EN 50461 (2006): Solar cells - Datasheet information and product data for crystalline silicon solar cells

SEMI Standards:

SEMI MF523-02: Practice for unaided visual inspection of polished silicon wafer surfaces

SEMI MF42-02: Test methods for conductivity type of extrinsic semiconducting materials

SEMI MF84-02: Test method for measuring resistivity of silicon wafers with an inline four-point probe

SEMI MF1535-04: Test method for carrier recombination lifetime in silicon wafers by non-contact measurement of photoconductivity decay by microwave reflectance

SEMI MF26-05: Test methods for determining the orientation of a semi-conductive single crystal

SEMI MF1530-04: Test method for measuring flatness, thickness, and total thickness variation on silicon wafers by automated non-contact scanning

SEMI MF533-02a: Test method for thickness and thickness variation of silicon wafers

SEMI MF1390-04: Test method for measuring warp on silicon wafers by automated noncontact scanning

SEMI MF657-99: Test method for measuring warp and total thickness variation on silicon wafers by noncontact canning

SEMI MF2074-03: Guide for measuring diameter of silicon and other semiconductor wafers

SEMI MF671-99: Test method for measuring flat length on wafers of silicon and other electronic materials

SEMI MF1188-05: Test method for interstitial oxygen content of silicon by infrared absorption with short baseline

SEMI MF1391-04: Test method for substitutional atomic carbon content of silicon by infrared absorption

SEMI MF1809-04: Guide for selection and use of etching solutions to delineate structural defects in silicon

SEMI MF1810-04: Test method for counting preferentially etched or decorated surface defects in silicon wafers

SEMI MF950-02: Test method for measuring the depth of crystal damage of a mechanically worked silicon slice surface by angle polishing and defect etching

DIN/VDE Standards:

DIN/VDE 0126-18-1 (2007): Solar Wafers–Part 1 "Datasheet information and project data for crystalline silicon solar wafer" (German version)

DIN/VDE 0126-18-2-1 (2007): Solar Wafers–Part 2-1 "Measuring the geometric dimensions of silicon wafers – Wafer thickness" (German version)

DIN/VDE 0126-18-2-2 (2007): Solar Wafers–Part 2-2 "Measuring the geometric dimensions of silicon wafers – Variations in thickness" (German version)

DIN/VDE 0126-18-2-3 (2007): Solar Wafers–Part 2-3 "Measuring the geometric dimensions of silicon wafers – Waviness and warping" (German version)

DIN/VDE 0126-18-2-4 (2007): Solar Wafers–Part 2-4 "Measuring the geometric dimensions of silicon wafers – Saw marks" (German version)

DIN/VDE 0126-18-3 (2007): Solar Wafers–Part 3 "Alkaline corrosion damage of crystalline silicon wafers – Method of determining the corrosion rate of mono and multi crystalline silicon wafers" (German version)

DIN/VDE 0126-18-4-1 (2007): Solar Wafers–Part 4-1 "Process for measuring the electrical characteristics of silicon wafers – Minority carrier lifetime, inline measuring method" (German version)

DIN/VDE 0126-18-4-2 (2007): Solar Wafers–Part 4-2 "Process for measuring the electrical characteristics of silicon wafers – Minority carrier lifetime, laboratory measuring method" (German version)

DIN/VDE 0126-18-5 (2007): Solar Wafers–Part 4 "Process for measuring the electrical resistance of silicon wafers" (German version)

DIN/VDE 0126-18-6 (2007): Solar Wafers–Part 6 "Method for measuring substitutional atomic carbon and interstial oxygen in silicon used for photovoltaics" (German version)

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Photovoltaic System Grounding

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October 2012

Solar America Board for Codes and Standards

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www.solarabcs.org/systemgrounding

Executive Summary

Photovoltaic (PV) power systems are capable of producing hazardous voltages and currents for decades. To ensure the safety of the public for these extended periods of time, PV systems must be properly designed and installed using the highest standards of workmanship.

This paper addresses the requirements for PV system grounding contained in the U.S. *National Electrical Code® (NEC®)* published by the National Fire Protection Association (NFPA). The *NEC* and the *NEC Handbook a*re copyrighted by NFPA and the term NFPA-70 is a trademark owned by the NFPA (NFPA, 2011). It does not address in any detail the various American or European standards that are used to design and produce electrical equipment, nor does it cover the many electrical codes used in other countries.

In the United States, the *NEC* establishes the legal installation requirements for PV systems, and these requirements are somewhat complex. The *NEC* requires that all exposed or accessible PV equipment and circuits be properly connected to earth (grounded) using specified methods and equipment. Source circuits in PV systems may be grounded or ungrounded as explained in this paper.

As installed PV systems age, grounding issues emerge that impact system safety. These issues include deteriorating electrical connections, inadequate grounding device design and installation, and the effects of non-code compliant system installations. Many of the required ground-fault protection devices in use today do not detect all possible ground faults, and, in some cases, fires and equipment damage have resulted from undetected ground faults. Both the *NEC* and Underwriters Laboratories (UL) hardware safety standards for the certification/listing of equipment are being revised to address many of these issues.

"As installed PV systems age, grounding issues emerge that impact system safety."

Table of Contents

DISCLAIMER 2

EXECUTIVE SUMMARY 3

AUTHOR BIOGRAPHY 4

SOLAR AMERICA BOARD FOR CODES AND STANDARDS 5

ACKNOWLEDGEMENTS 5

INTRODUCTION 6

DEFINITIONS 7

NATIONAL ELECTRICAL CODE REQUIREMENTS 9

SYSTEM GROUNDING 13

MICROINVERTERS AND AC PV MODULES—DIFFERENT REQUIREMENTS 18

GROUND FAULTS AND GROUND-FAULT PROTECTION DEVICES 20

THE CONNECTION TO EARTH 25

UTILITY VS *NEC* REQUIREMENTS 26

ACRONYMS 27

REFERENCES 28

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John Wiles is a senior research engineer at the Southwest Technology Development Institute, College of Engineering at New Mexico State University in Las Cruces, New Mexico.

He bought his first copy of the *National Electrical Code® (NEC®)* in 1961 and rewired his parent's home to the latest *NEC* requirements. After graduating from West Virginia University with a bachelor's degree in electrical engineering, he became an officer in the United States Air Force. He earned a master's degree in electrical engineering and spent 24 years in the Air Force working on automatic control systems and tactical weapons systems. He has taught college courses at West Virginia University and the U.S. Naval Academy. He installed his first photovoltaic (PV) power system in 1984 and has been involved in the design, installation, inspection, and testing of PV systems for 28 years. He is a member of the Underwriters Laboratories Standards Technical Panels for PV modules, inverters, racks, and direct current PV arc fault interrupters. He is secretary of the PV Industry Forum, an organization that develops and submits PV proposals for improving the *NEC*. He writes articles on PV and the *NEC* for the *International Association of Electrical Inspectors News* and gives PV/*NEC* presentations throughout the country to PV designers, installers, and electrical inspectors. He lives with his wife Patti, two dogs, and a cat in an energy-efficient home with a 5-kilowatt utility-interactive PV system and full house battery backup.

Solar America Board For Codes And Standards

The Solar America Board for Codes and Standards (Solar ABCs) is a collaborative effort among experts to formally gather and prioritize input from the broad spectrum of solar photovoltaic stakeholders including policy makers, manufacturers, installers, and consumers resulting in coordinated recommendations to codes and standards making bodies for existing and new solar technologies. The U.S. Department of Energy funds Solar ABCs as part of its commitment to facilitate widespread adoption of safe, reliable, and cost-effective solar technologies.

For more information, visit the Solar ABCs website:
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Acknowledgements

The author thanks the following individuals for their critical review and comments on this paper: Greg Ball, BEW Engineering; Ward Bower; Bill Brooks, Brooks Engineering; Marv Dargatz, Solar Edge; Jim Eichner, Schneider Electric; Marvin Hamon, Hamon Engineering; Pete Jackson, City of Bakersfield; Sarah Kurtz, National Renewable Energy Laboratory; Rhonda Parkhurst, City of Palo Alto; Dan Rice, Conergy; Michael Sheehan, Interstate Renewable Energy Council; Don Warfield, Ameresco; and Brian Wiley.

Introduction

Proper grounding of a photovoltaic (PV) power system is critical to ensuring the safety of the public during the installation's decades-long life. Although all components of a PV system may not be fully functional for this period of time, the basic PV module can produce potentially dangerous currents and voltages for the life of the system. Effective, code-compliant, properly maintained grounding helps ensure the overall safety of the system, even if it is no longer producing usable power.

More than a century ago, the United States and most of the Americas elected to use grounded electrical systems, in which one of the circuit conductors is connected to the earth. The rest of the world (ROW) for the most part chose to employ ungrounded electrical systems, in which none of the circuit conductors are connected to earth. The normally non-energized metal surfaces of electrical equipment are, however, required to be connected to earth in the ROW.

This paper addresses the requirements for PV system grounding contained in the U.S. *National Electrical Code®* (*NEC®*) published by the National Fire Protection Association (NFPA). The *NEC* and the *NEC Handbook* are copyrighted by NFPA and the term NFPA-70 is a trademark owned by the NFPA (NFPA, 2011). It does not address in any detail the various American or European standards that are used to design and produce electrical equipment, nor does it cover the many electrical codes used in other countries.

The *NEC* requires that the authority having jurisdiction (AHJ or electrical inspector) examine all electrical equipment for safety. Electrical equipment has generally been standardized from an input/output interconnectivity perspective through the Nationally Recognized Testing Laboratory (NRTL) evaluation, certification, and listing process. The NRTL certification ensures the equipment meets all applicable safety standards. Underwriters Laboratories (UL) coordinates the development of many of the safety standards that apply to PV systems (e.g. UL 1703; UL 1741). The U.S. Occupational Safety and Health Administration (OSHA) authorizes NRTLs to test and certify/list electrical equipment to various standards. The American National Standards Institute (ANSI) authorizes the development of standards by UL and others. Although the *NEC* does not specifically require all equipment to be certified/listed, many local jurisdictions and many AHJs establish requirements that all equipment be certified/listed because they feel unqualified to examine uncertified/unlisted equipment for safety as the *NEC* requires.

Definitions

Before discussing the subject of grounding, the term "grounding" requires definition. There are two types of grounding in electrical and PV systems—equipment grounding and system grounding.

Equipment Grounding

Equipment grounding is known in the ROW as safety grounding or protective earthing. The equipment grounding system in the United States effectively bonds (electrically connects) all exposed non-current carrying metal parts of the electrical system together and eventually connects these metal parts to the earth (ground).

Metal enclosures containing electrical conductors or other electrical components may become energized as a result of insulation or mechanical failures. Energized metal surfaces, including the metal frames of PV modules, can present electrical shock and fire hazards.

By properly bonding exposed metal surfaces together and to the earth, the potential difference between earth and the conductive surface during a fault condition is reduced to near zero, reducing electric shock potential. The proper bonding to earth by the equipment grounding system is essential, because most of the environment (including most conductive surfaces and the earth itself) is at earth potential. The conductors used to bond the various exposed metal surfaces together are known as equipment grounding conductors (EGCs).

In a conventional electrical power system (utility, generator, or battery sourced), the equipment grounding system provides a path for ground-fault currents to return to the energy source. By allowing these currents to return to the source in an expeditious manner, properly positioned overcurrent protective devices (OCPDs, typically fuses or circuit breakers) are allowed to function, removing the source of the fault currents. The National Electrical Code Requirements part of this paper describes equipment grounding procedures used in the United States.

System Grounding

In system grounding, one of the circuit (current-carrying) conductors is bonded (connected) to the equipment grounding system and also to earth. This is known as *functional grounding* in the ROW. The circuit conductor that has been connected to the equipment grounding system and to earth is known as the *grounded conductor*. The connection between the grounded conductor and the equipment grounding system is known as the system bonding jumper in the *NEC*. Only one system bonding jumper is allowed in each separate electrical system in which the system grounded conductor is isolated from the grounded conductors of the source or other systems. See *NEC* Article 100 for definitions of bonding, bonding jumpers, and system bonding jumpers. Section 250.28 expands on the proper installation of system and main bonding jumpers.
The system ground connection, made by a system bonding jumper, is the path that allows fault currents to return to the source. If the equipment grounding system and the system bonding jumper have sufficiently low impedance (i.e., proper conductor size and good connections), currents that originate from an ungrounded conductor faulting to a grounded surface or the equipment grounding system will be sufficient to trip the OCPD supplying that circuit. PV systems, as noted below, may not perform the same under fault conditions as other types of electrical systems.

Earth Connection

The metallic device used to make contact with the earth is the *grounding electrode*. The conductor that connects the central grounding point (where the equipment grounding system is connected to the grounded circuit conductor on grounded systems) and a grounding electrode that is in contact with the earth is known as the *grounding electrode conductor* (GEC).

Solidly Grounded

The *NEC*, in Article 100, defines *solidly grounded* as being connected to ground without inserting any resistor or impedance device in the circuit. This definition does allow for the use of fuses, circuit breakers, and mechanical relay contacts in certain grounding circuits, but typically precludes the use of solid-state devices such as transistors, silicon controlled rectifiers, and bi-junction field effect transistors. This is because these devices would likely be considered impedance devices. Although language in *NEC* 690.41 allows equivalent grounding methods in listed equipment, no listing agencies certify products in a configuration other than solidly grounded.

National Electrical Code Requirements

Article 250 in the *NEC* covers most of the grounding requirements for any electrical system. This article is more than 30 pages long, and it is not possible to elaborate on or restate all of these requirements here. Article 690 has other requirements for grounding PV systems, and many parts of the *NEC* are revised every three years, including Articles 250 and 690. To further complicate matters, different editions of the *NEC* are in use in different jurisdictions, from the most recent edition (2011) back to the 2002 *NEC* and earlier versions.

For the entire text of the *NEC* and additional explanatory material provided by NFPA, go to the *NEC* Handbook (NFPA, 2011). The Soares book on grounding published by the International Association of Electrical Inspectors (IAEI, 2011) is also an excellent resource on *NEC* requirements for grounding. For an individual installation, refer to the *NEC* edition in use in that jurisdiction to establish specific project requirements. This paper will highlight a few of the *NEC* requirements for both equipment and system grounding that apply to PV systems and that are sometimes overlooked in PV installations. Unless specifically mentioned, all references to the *NEC* in this paper will be to the 2011 edition.

Good Workmanship Is an *NEC* Requirement

In Section 110.12, the *NEC* states that good workmanship is required on all electrical installations. The phrase "in a neat and workmanlike manner" is not defined in the *NEC*, but has been addressed in other material such as the National Electrical Contractors Association Standard 1. The electrical trades teach good workmanship through on-the-job-training and in more formal courses taught in International Brotherhood of Electrical Workers schools. The workmanship associated with the installation of PV systems is coming under increased scrutiny by inspectors throughout the country.

Unfortunately, this scrutiny has found some less than quality PV installations. Fires have originated because metal conduits have not been installed properly and conductors have not been installed properly in the conduits. Conductors have had insulation damaged during installation, and in instances when proper grounding methods or hardware was not used, ground faults have occurred that led to fires. When the electrical system is not installed properly and is not in compliance with *NEC* requirements, the safety of the system becomes questionable, either at the time of the installation or at some future date as the system ages and deteriorates.

Equipment Grounding

Section 690.43 of the *NEC* requires that PV systems have equipment grounding systems when there are any exposed metal or conductive surfaces that may become energized. This requirement applies to PV systems operating at any voltage, including small standalone 12-volt PV systems and even a 6-volt, PV-powered water pump on a solar hot water system. The exposed metal surfaces include PV module frames, metal mounting racks, metal conduits, and enclosures for combiners, disconnects, inverters, and charge controllers as well as other electrically conductive parts. Exposed conductors with failing insulation as a result of a 40- or 50-year-old less-than-optimal installation could even energize a metal roof under a PV array.

The emergence of PV modules with nonmetallic frames may simplify the grounding of PV modules. The 690.43 requirement is a reiteration of the basic requirement for equipment grounding found in Article 250, Part VI. For a complete assessment of the state of module grounding according to the *NEC* and various UL Standards requirements, see the Solar ABCs report *Photovoltaic Module Grounding* (Ball, Zgonena, & Flueckiger, 2012).

In many electrical power systems, the *NEC* allows the use of a metallic raceway such as EMT (electrical metallic tubing) or RMC (rigid metal conduit) to be used as the EGC. However, many PV installers and PV systems integrators choose to use a separate EGC, which would be required if a nonmetallic raceway was used. The use of a distinct conductor for the EGC is generally a good idea, because it does not rely on the mechanical/electrical joints associated with metal conduit systems. Nonmetallic wiring methods include nonmetallic rigid conduit (PVC) and nonmetallic sheathed cables (types NM and TC).

Equipment Grounding—Finer Points

PV Direct Current Circuits. Sections 690.43, 690.45, and 690.46 cover *NEC* requirements specific to the equipment grounding of PV source and PV output circuits. The basic requirement refers to *NEC* section 250.110 and is outlined in the Equipment Grounding section above. The equipment in direct current (DC) portions of the PV system may be grounded using conductors as outlined above with appropriate connections to each metal surface. In general, when a copper wire is connected to a metal surface to be grounded, some sort of certified/listed grounding device must be used. This equipment grounding connection may be a listed ground bar kit, a standard electrical lug suitable for the application or a terminal or lead on the equipment, or a specific grounding device certified/listed for the application. UL is developing a new PV racking standard 2703 (UL, 2010) that will establish the requirements for certifying/listing PV racking systems as EGCs.

As in other electrical systems, the rating of the OCPD protecting a DC PV circuit is used to determine the size of the required EGC for that circuit (*NEC* Table 250.122). The EGC will typically have low enough resistance or impedance to allow timely activation of the OCPD for that circuit when a ground-fault current flows through it.

Although this system works for AC systems supplied by stable power supplies with high available fault currents, it may not be as effective for PV DC circuits. PV DC circuits have limited available fault current that is a function of the incident sunlight energizing the supply source and the configuration of the system (number of parallel circuits feeding the faulted circuit). The available fault current may not be enough to enable the OCPD to function under some conditions, such as during cloudy weather or in the early morning or late afternoon. To address this issue, PV systems have ground-fault detection requirements that account for the potentially low fault current. These requirements are described in the Ground Faults and Ground-Fault Protection Devices part of this paper.

The current-limited nature of PV modules allows some DC circuits to be installed without an OCPD if there isn't sufficient fault current to damage the circuit conductors or the PV modules themselves. When an OCPD is not required, the rated short circuit current (Isc) for the DC PV source or output circuit is used in *NEC* Table 250.122 as a pseudo OCPD and an EGC size is specified by the value of that Isc. The exception to requiring OCPD on PV source circuits is usually applied to smaller residential PV systems with only one PV source circuit or two strings of parallel-connected source circuits. The exception also extends to PV output circuits, however, such as one or two parallel connected and equally sized combiner box output circuits.

Inverters and Other Electronic Devices. UL Standard 1741 (UL, 2010) requires that inverters have terminals, leads, or other provisions to accept EGCs for all inputs and outputs. For a typical PV utility-interactive inverter, there should be an equipment grounding terminal for each DC input as well as for the AC output. These terminals may be on a single grounding busbar or may be physically separated but electrically connected. These terminals will generally be electrically connected/bonded to the metallic enclosure of the inverter. Charge controllers for stand-alone or multi-mode

systems and PV combiners will have similar provisions for EGCs. Some microinverters and AC PV modules as well as some DC-to-DC converters may have external terminals on the enclosure to connect the EGCs required by the *NEC* and UL 1741.

Conduit Bonding. When DC PV source and DC PV output circuits are installed in metal conduits, the metal conduits must have grounding/bonding bushings if the enclosures they connect to have concentric knockouts and if the circuits operate at more than 250 volts (*NEC* 250.97). Many PV systems using "string" inverters have a maximum system voltage of more than 250 volts, and these same systems may use combiners, disconnect switches, and inverters that have concentric knockouts. If the required grounding/bonding bushings are not installed, electrical grounding of the conduit through the fittings may be lost over time. The mechanical connections between the conduit and the enclosures can loosen due to thermal and environment stresses, for example, posing a safety hazard if ground faults occur in the conduits.

Enclosure Grounding. Commonly available disconnect switches and equipment enclosures are listed devices, and are furnished with instructions and labels indicating how they are to be connected to the grounding system. In section 110.3(B), the *NEC* requires that these instructions (sometimes discarded by the electrician and the PV installer) and product labels be followed. The metal of these enclosures is frequently not sufficiently thick to hold thread cutting screws, and ordinary sheet metal screws are no longer allowed for making grounding connections (250.8). Most of these enclosures have a label that indicates that a specific grounding bar kit be used to make equipment grounding connections to the enclosure. Other enclosures have a welded, threaded boss to accept EGC connections.

In some cases, these instructions and labels are ignored and a lug is attached directly to the enclosure surface, sometimes without removing any insulating finish (as 250.12 requires). In other cases, a sheet metal or green thread cutting screw is used for grounding the box in PV applications. Neither method complies with the *NEC* requirements as noted in the instructions and/or on the labels for these products (110.3[B], 250.8).

Aluminum Grounding. Although steel has been used for many decades for electrical enclosures, many new products from the PV Industry have aluminum enclosures. Aluminum rapidly oxidizes to an insulating surface when exposed to air. If the manufacturer has not provided a specific terminal, lead, or lug for equipment grounding, surface preparation and oxidation protection is necessary to achieve acceptable equipment grounding. This also applies to aluminum framed PV modules.

Not Continuous, but Green. EGCs are not required to be continuous or to be irreversibly spliced. They may be insulated or bare depending on the installed location. When insulated, an EGC should have insulation marked or colored green or green with yellow stripes (200.119). For long-term PV system durability, colored insulations (red, white, green, etc.) should be used only when absolutely necessary, because UV radiation may result in a shortened life or fading colors. Most AHJs will allow exposed black insulated EGC to be marked with a green marking if the installation requires an insulated EGC, as some do over architectural metal roofs. A proposal has been submitted for the 2014 *NEC* to permit this marking.

Routing for Performance and Safety. The EGCs for the DC portions of the circuit should be routed with the circuit conductors as required by 300.3(B). Although 250.134(B) EX 2 permits EGCs on DC circuits to be run separately from the DC circuit conductors, this may not be a good practice in PV systems.

Overcurrent devices are tested and evaluated with a minimum of circuit inductance. As the inductance in a circuit increases (increasing circuit time constant), however, overcurrent devices have an increasingly difficult time clearing the fault current and extinguishing the DC arc. The sizing requirement for overcurrent devices in PV DC source and DC output circuits is 1.56 times the Isc. Low fault currents during periods of low irradiance may not activate OCPD under fault conditions. The DC circuits should be designed with every possible method applied to ensure the timely activation of overcurrent devices under fault conditions. Keeping the fault circuit inductance low keeps the time constant low and facilitates the operation of the overcurrent devices.

During the operation of a single-phase inverter in the stand-alone inverting mode (either an off-grid system or a utility-interactive system with battery backup), the DC current between the batteries and the inverter may have 120 hertz (Hz) ripple currents that are in excess of the average DC currents. These ripple currents interact with ferrous enclosures in the same manner as AC currents, indicating that the EGCs should be routed with the DC circuit conductors. The allowance in the *NEC* (250.134[B]EX2) that the EGCs in DC systems may be run separately from the circuit conductors should not be followed in PV systems with battery backups.

SYSTEM GROUNDING

Before the 2005 edition, the *NEC* required that all PV systems have one of the DC circuit conductors grounded whenever the maximum system voltage was more than 50 volts (690.41). Section 690.35, which allows PV systems meeting certain requirements to have ungrounded PV circuits, was added to the 2005 *NEC*. This change permitted the use of utility-interactive inverters without isolation between the DC input circuits and the AC outputs—called non-isolated inverters in the ROW—for cost savings and increased efficiency. Most PV systems in the United States use isolated inverters with internal transformers (isolated inverters in the ROW) as of 2012, but non-isolated inverters and ungrounded PV systems are being certified/listed and are making market inroads.

Note that ungrounded arrays can also be used with isolated inverters. In all cases, an ungrounded array must be provided with equivalent protection for ground faults, as required by *NEC* 690.35.

Grounded Systems

A PV system is defined as a grounded system when one of the DC conductors (either positive or negative) is connected to the grounding system, which in turn is connected to the earth. The conductor that is grounded usually depends on the PV module technology. Most modules can be used with a negative grounded conductor or even in an ungrounded system, but a few PV module technologies require the positive conductor to be connected to earth. Note that Article 690 uses the terms "system" [690.35] and "array" [690.5] in the context of grounded or ungrounded PV DC circuits. The term "system" is more appropriate both for consistency with AC system terminology for separately derived systems and for clarity. There can be multiple "arrays" feeding an inverter in which the single connection of the DC conductor to ground typically occurs.

Color Codes. The DC grounded conductor must have insulation colored white or gray or have three white stripes if it is 6 AWG (American wire gauge) or smaller. Larger size conductors must be marked with these colors at their termination points. Grounded PV source and PV output conductors 6 AWG and smaller are allowed to be marked in the same manner as larger conductors, in order to allow the use of the durable, black-insulated USE-2 and PV cable/PV wire in exposed locations within the PV array (NEC 200.6).

Grounding Electrode Conductor—Installation. On utility-interactive PV systems, the connection between the DC grounded circuit conductor and the grounding system is usually made through the ground-fault protection device (GFPD) internal to most non-battery based utility-interactive inverters. UL Standard 1741 requires a provision be made for the internal connection of a DC GEC. Microinverters that ground one of the module circuit conductors will have an internal GFPD and will also require a GEC terminal. The connection at the inverter for the GEC is usually a marked GEC terminal. From that terminal on the certified/listed inverter, the PV installer must adhere to *NEC* requirements to make the connection to earth through a grounding electrode. These requirements are described in Section 690.47(C), which modifies and adds to the requirements in Article 250.

The *NEC* had significant changes in Section 690.47(C) of the 2005, 2008, and 2011 editions that address the DC GEC connection. The permissive requirements of this section in the 2005 *NEC* or the permissive requirements in the 2008 *NEC* may be applied to connect the GEC when installing a system in jurisdictions using either version.

The 2011 *NEC* is easier to understand and includes all three methods for connecting the DC GEC described in the 2005 and 2008 *NEC*. Section 690.47(C) from the 2011 *NEC* is repeated below and may help in understanding the requirements for 690.47(C) in the somewhat confusing 2008 *NEC*. Note that paragraph 690.47(C)(1) and 690.47(C)(2) in the 2011 *NEC* align with 690.47(C)(1) and 690.47(C)(2) in the 2005 *NEC* and paragraph 690.47(C)(3) in the 2011 *NEC* aligns with 690.47(C) in the 2008 *NEC*.

690.47(C) Systems with Alternating and Direct Current Grounding Requirements. Photovoltaic systems having dc circuits and ac circuits with no direct connection between the dc grounded conductor and ac grounded conductor shall have a dc grounding system. The dc grounding system shall be bonded to the ac grounding system by one of the methods in (1), (2), or (3).

This section shall not apply to ac PV modules.

When using the methods of (C)(2) or (C) (3), the existing ac grounding electrode system shall meet the applicable requirements of Article 250, Part III.

Informational Note No. 1: ANSI/UL 1741, *Standard for Inverters, Converters and Controllers for use in Independent Power Systems*, requires that any inverter or charge controller that has a bonding jumper between the grounded dc conductor and the grounding system connection point have that point marked as a grounding-electrode conductor (GEC) connection point. In PV inverters, the terminals for the dc equipment grounding conductors and the terminals for ac equipment grounding conductors are generally connected to, or electrically in common with, a grounding busbar that has a marked dc GEC terminal.

Informational No.2: For utility-interactive systems, the existing premises grounding system serves as the ac grounding system.

(1) Separate Direct-Current Grounding Electrode System Bonded to the Alternating-Current Grounding Electrode System. A separate dc grounding electrode or system shall be installed, and it shall be bonded directly to the ac grounding-electrode system. The size of any bonding jumper(s) between ac and dc systems shall be based on the larger size of the existing ac grounding electrode conductor or the size of the dc grounding electrode conductor specified by 250.166. The dc grounding electrode system conductor(s) or the bonding jumpers to the ac grounding electrode system shall not be used as a substitute for any required ac equipment grounding conductors.

(2) Common Direct-Current and Alternating-Current Grounding Electrode. A dc grounding electrode conductor of the size specified by 250.166, shall be run from the marked dc grounding electrode connection point to the ac grounding electrode. Where an ac grounding electrode is not accessible, the dc grounding electrode conductor shall be connected to the ac grounding electrode conductor in accordance with 250.64(C)(1). This dc grounding electrode conductor shall not be used as a substitute for any required ac equipment grounding conductors.

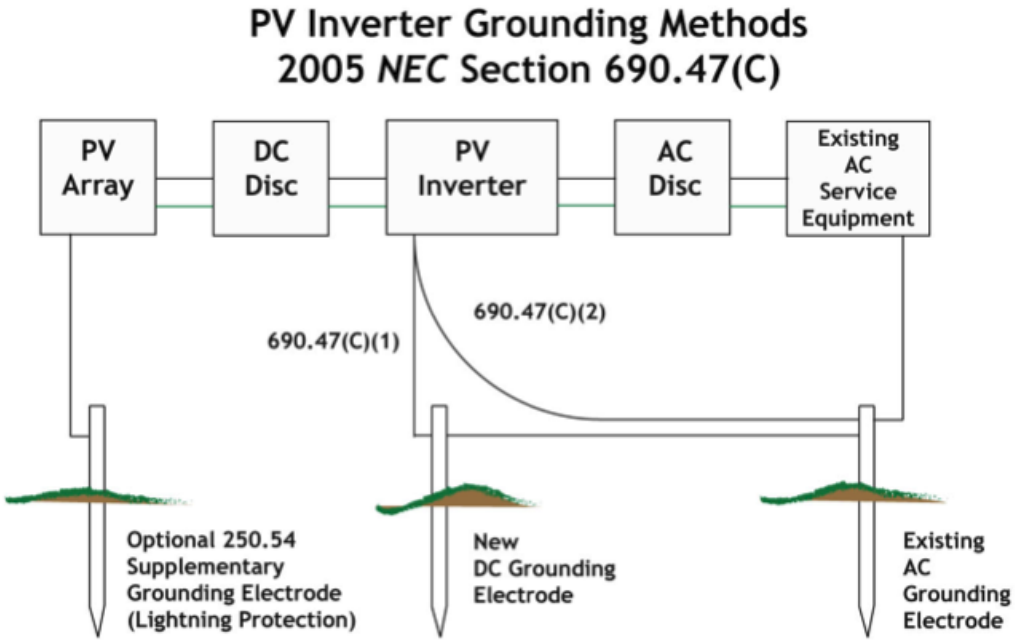
(3) Combined Direct-Current Grounding-Electrode Conductor and Alternating-Current Equipment Grounding Conductor. An unspliced, or irreversibly spliced, combined grounding conductor shall be run from the marked dc grounding-electrode conductor connection point along with the ac circuit conductors to the grounding busbar in the associated ac equipment. This combined grounding conductor shall be the larger of the size specified by 250.122 or 250.166 and shall be installed in accordance with 250.64(E).

Although any of the three methods of making connections to the inverter grounding electrode terminal may be used, there are advantages and disadvantages to each.

Section 690.47(C)(1) in the 2011 *NEC* (similar to 690.47[C][1] in the 2005 *NEC*) has the advantage of routing surges picked up by the array from nearby lightning strikes more directly to earth than methods (C)(2) and (C)(3). Because a bonding conductor between the new DC grounding electrode and the existing premises AC-grounding electrode is required, the size, routing, and cost of that conductor must be considered.

Section 690.47(C)(2) in the 2011 *NEC* (similar to 690.47[C][2] in the 2005 *NEC*) uses fewer components than the 690.47(C)(1) method and also routes surges to earth without getting near the AC service equipment. See Figure 1 below for these two GEC routings.

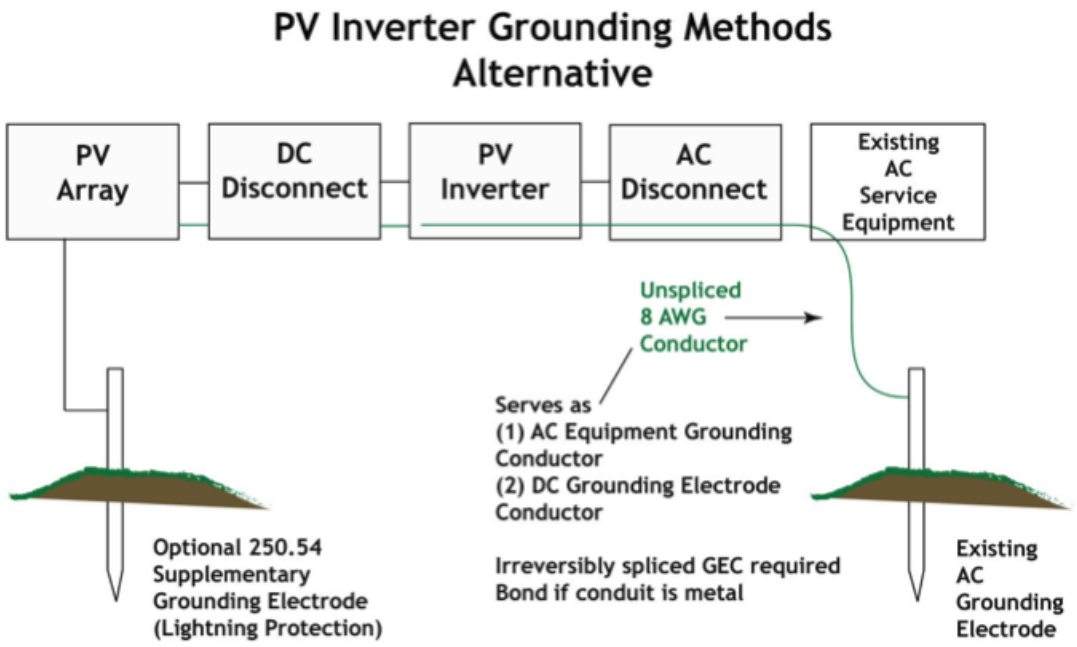
Figure 1. PV Inverter Grounding Methods—2005 *NEC* Section 690.47(C)



Section 690.47(C)(3) in the 2011 *NEC* (similar to 690.47[C] in the 2008 *NEC*) combines the inverter AC EGC with the DC GEC into a single conductor and thereby uses less copper. However, this conductor is required to be bonded (GEC requirement) at the entrance and exit of each metallic conduit and metal enclosure. For conductor sizes greater than about 6 AWG, bonding jumpers are typically used to bond conduit and enclosures, because the conductor must remain unspliced or irreversibly spliced (GEC requirement). Also, any lightning-induced surges picked up by the array may be routed more directly to the service equipment and may be more likely to enter the premises wiring system than when GECs are routed more directly to earth.

See Figure 2 for the combined EGC/GEC routing. Note that the 2008 and 2011 *NEC* allow this combined conductor to be terminated at the first panel board that has a grounding busbar with an attached GEC to a grounding electrode.

Figure 2. PV Inverter Grounding Methods Alternative



Note: 8 AWG is the minimum allowed, and a larger conductor may be required.

Section 690.47(D)—2008 NEC Only. Section 690.47(D) in the 2008 *NEC* is not entirely clear and deals with lightning-induced surge currents in PV arrays. Because surge reduction is not directly a safety issue, this section was removed from the 2011 *NEC*. The original intent was that all ground-mounted PV arrays have a GEC routed directly from the array frames to earth in as direct manner as possible. This would be similar to the optional auxiliary grounding electrodes permitted by 250.54 that need not be bonded to any other grounding electrode. Also, the intent was to have a similar array grounding system on PV arrays mounted on buildings where the array and the inverter were on different structures. *NEC* Section 250.54 is still available to those who wish to increase system longevity through additional surge reduction techniques.

Grounding Electrode Conductor Size. GECs associated with the inverter are related to grounding the DC part of the system and *NEC* 250.166 and 250.122 (for the 690.47[C][3] option) establishes the size. That size is primarily based on the type of grounding electrode being used, which in turn is determined by the installation method selected from the options in 690.47(C). Small residential and commercial PV systems in the range of 2 to 10 kilowatts may find that only a 6 AWG GEC is needed when the installer uses a ground rod. A 4 AWG GEC is required when the existing premises AC grounding electrode is a concrete encased grounding electrode (UFER). Large PV systems require careful assessments of the *NEC* DC requirements, the AC grounding system, the inverter manual grounding requirements, and the utility grounding requirements when the utility connection occurs at medium voltage. In some situations the DC GEC may have to be as large as the largest DC conductor in the PV system.

Other sections of Article 250 such as 250.64(E) require that the GEC be continuous or irreversibly spliced from the GEC terminal on the inverter to the grounding electrode. If the GEC is routed through metal conduits or enclosures, the GEC must be bonded to the conduit or the enclosure at the entrance and exit points of each conduit or enclosure to avoid inductive (choke) effects that would prevent lightning-induced surges from reaching earth.

Ungrounded Systems

When an installation meets the requirements of 690.35, the PV system can be ungrounded. Inverters designed for use with ungrounded systems will have no requirement for a GEC. However, the NRTLs and the manufacturers have not yet fully understood the UL 1741 requirements, and non-isolated (transformerless) inverters are on the market with a marked grounding electrode terminal. This creates an issue for the PV installer because *NEC* 110.3(B) requires compliance with the product labels and that would imply that a DC GEC is needed. Neither the *NEC* nor UL Standard 1741 specifically require one, however. Installing the unneeded GEC will usually do no harm, other than increase the price of the system, and may provide a lower impedance path to earth for surge currents.

Color Codes. The *NEC* does not prescribe color codes for ungrounded DC conductors, except that they may not be green, green with yellow stripes, white, gray, or have three white stripes. By convention, red would normally be used for the positive conductor and black for the negative conductor. However, conductors with colored insulation should be avoided when exposed to UV radiation, as they may not be as durable as black insulated conductors.

Ambiguity in the NEC. The current wording of 690.47(B) in the *NEC* relating to DC systems leaves a hole in the *NEC* with respect to ungrounded PV systems. The *NEC* may require a DC grounding electrode on ungrounded PV systems for the purpose of DC equipment grounding. In actuality, with a common equipment grounding busbar or connection between the DC equipment grounding terminals and the AC equipment grounding terminals, the exposed metal surfaces of the DC equipment are grounded when the AC EGC is connected to the grounding system at the AC main bonding jumper. The following proposal for the 2014 *NEC* has been submitted to clarify this area:

> 690.47(B) (NEW)
>
> Add a new third paragraph as follows:
>
> Ungrounded dc PV arrays connected to utilization equipment with common ac and dc equipment grounding terminals shall be permitted to have equipment grounding requirements met by the ac equipment grounding system without the requirement for a dc grounding electrode conductor or grounding system.
>
> Substantiation:
>
> The first paragraph of 690.47(B), as currently written, applies to stand-alone ungrounded dc PV systems where a new grounding electrode and grounding electrode conductor are required. There is no requirement directly addressing the ungrounded PV array connected to a utility-interactive inverter as allowed by 690.35.
>
> Most ungrounded PV arrays will be connected to utility-interactive inverters and those inverters have common ac and dc equipment grounding terminals. The PV array dc equipment grounding conductors, when connected to such inverters, have the array dc equipment grounding conductors connected to earth through the ac equipment grounding system and the existing ac grounding system. Additional grounding electrodes and grounding electrode conductors are not required, but may be used.

Of course, meeting system equipment grounding requirements in this manner may not be the best method to reduce potential damage from lightning-induced current surges and overvoltage. (Note the use of the phrase "shall be permitted," which indicates that this will be an option.) The optional system grounding of 250.54 should be considered in high lightning areas, although a fully engineered and listed lightning protection system would be a better choice than simply adding electrodes.

Microinverters And AC Pv Modules—Different Requirements

PV modules and microinverters combined/assembled in the field or at the dealer or distributor may not meet the intent, definition, or requirements associated with true AC PV modules as defined in 690.2 and in 690.6. These combinations of devices also may not meet the requirements for an AC PV module in UL Standard 1741.

As of early 2012, there is no specific size associated with either microinverters or AC PV modules. The power outputs are increasing with nearly every new product. In most cases, *NEC* requirements that apply to the larger string and central inverters will also apply to the microinverter. Microinverters have similar AC output characteristics, connections, and code requirements to AC PV modules.

Always follow the instructions supplied with the listed product (*NEC* 110.3[B]). The material below is not a substitute for compliance with the instruction manual, the *NEC,* or local codes.

Grounding. Both the AC PV module and the microinverter will require equipment grounding connections if there is any exposed metal in these devices. A GEC connection is required when the microinverter connects either the negative or positive inverter input conductor (from the PV module) to ground through the inverter case. Many microinverter manufacturers will ground the positive DC conductor to allow the inverter to be paired with the widest range of PV modules.

Equipment/Safety Grounding. The AC output circuit cable of some microinverters does not have an EGC. This EGC must be started (originated) in the transition box on the roof where each set of inverters has the final factory AC output cable connected to another wiring system. This AC EGC must be routed back to an AC grounding point as it is in any other AC circuit. There is no requirement that it be unspliced, and the size will typically be determined per Table 250.122. The AC EGC must also be routed to each metal inverter enclosure either through the AC output cable or as a separate conductor connected to a lug on that enclosure.

System Grounding. True AC PV modules, with no readily accessible DC conductors or DC disconnects, will normally not require a GEC or GEC terminal.

Under UL Standard 1741, if the microinverter isolates the DC grounded input conductor (assuming a grounded PV module) from the AC output (with a transformer or other method), the microinverter must have a DC GEC running from the grounding electrode terminal on the microinverter case to a DC grounding electrode. If the microinverter operates the PV module as an ungrounded system (neither positive nor negative connected to ground), then no GEC would be required.

Section 690.47(C) in the 2008 *NEC* and 690.47(C)(3) in the 2011 *NEC* permit the use of a combined AC EGC and DC GEC from the inverter. UL 1741 requires the DC GEC terminal on the outside of the inverter. If this combined conductor option is elected, then the most stringent requirements that apply to either the EGC or the GEC must be followed. When routed in conduit (for physical protection), a GEC as small as 8 AWG may be allowed (250.166). The combined conductor may be this size assuming that the required EGC is 8 AWG or less (250.122). Section 250.64 requires that the GEC (and hence the combined conductor) be bonded to the input and output of each metal conduit (where used) as well as any metal enclosure that it is routed through until it gets to the main grounding

bar in the AC supply equipment. The bonding requirement and 8 AWG size would rule out the use of 10 AWG type non-metallic sheathed cable for the AC output circuit. The bonding requirement may also be cumbersome to implement multiple times, and the routing of this combined conductor may induce lightning surges to enter the main load center and other branch circuits. Furthermore, if the existing AC grounding electrode for the structure is encased in concrete, the GEC from the inverter may have to be a 4 AWG conductor (250.166).

The alternate methods of routing the GEC allowed in 690.47(C) in the 2011 *NEC* might provide better solutions. These solutions and their pros and cons were covered above in the Systems Grounding part of this report.

AC PV Module Grounding—A Gray Area. Combinations of a microinverter and a PV module with exposed DC connectors and DC conductors between the PV module and the microinverter are being certified/listed as AC PV modules. Some of these products have instruction manuals that say the microinverter may not be removed from the PV module. Other manuals give specific instructions for removing the microinverter from the PV module for repair. At issue is the definition of an AC PV module as a factory assembled unit and the potential need to meet all DC *NEC* requirements for these products with exposed DC connectors and DC conductors. Connectors are subject to loosening, corrosion, or intentional opening in the field. Connectors and conductors are also exposed to environmental degradation, ground faults, and animal damage.

Another concern is the microinverter-to-PV module frame bonding when the mechanical/electrical connection is broken in the field. When the microinverter is replaced, the bonding connection must be reestablished following the instructions in the product manual, which have been evaluated during the NRTL certification/listing of the product. In the future, these issues will be addressed in UL 1741 and possibly in the *NEC*.

At this time, the best strategy for installers is to follow the instruction manual and labels found on the certified/listed product as required by *NEC* section 110.3(B)

Ground Faults And Ground-Fault Protection Devices

Ground Faults—More Than the *NEC* Definition

The *NEC* defines a ground fault as an unintentional connection between an ungrounded conductor and a grounded conductor or surface (Article 100 Definitions). Although this definition is suitable and adequate for electrical systems sourced by the utility, generator, or batteries, it does not fully address the limited fault current scenarios found in PV systems.

A ground fault in a PV system (and other electrical systems) also occurs when any circuit conductor (either ungrounded or grounded) comes in contact with an EGC or grounded surface. Because there is only one system bonding jumper in each system, when a ground fault occurs with a grounded conductor, the current that normally flows only in the grounded circuit conductor will now also flow in the EGC and the main bonding jumper. The current will flow in the two paths in inverse proportion to the resistance of the parallel paths. Currents in unintended paths can start fires if conductors or other metallic paths overheat or if the voltage at an open circuit is sufficient to sustain an arc.

Ground-Fault Protection

Because PV modules are current-limited sources and PV current is a function of the environmental effects of irradiance and temperature, overcurrent protection in PV circuits is not designed and installed like it is in voltage-sourced power systems. Normally, OCPD in PV systems is 156% of the rated Isc of the module. In many fault scenarios, there is insufficient available Isc to activate OCPD. Although OCPDs are required to deal with some overcurrent issues in PV systems, other methods are required to effectively deal with ground faults in the DC circuits.

Section 690.5 of the 1987 *NEC* added new requirements intended to reduce fire hazards resulting from ground faults in PV systems mounted on the roofs of dwellings. The intent is not to provide shock protection, because the 5 milliamperes (the current level required for AC ground-fault circuit interrupters [GFCI] anti-shock protection) level of protection would not be possible on a PV array with distributed leakage currents. The requirement is also not to be confused with a DC GFPD. The GFPD is intended to deal only with ground faults (both grounded conductor and ungrounded conductor) and not line-to-line faults.

The requirements for the GFPD were modified in subsequent revisions of the *NEC*. The requirements for the device in the current *NEC* are:

- Detect a ground fault
- Interrupt the fault current
- Indicate that there was a ground fault
- Open the ungrounded PV conductors or cause the inverter or charge controller to stop exporting power.

In the 2008 *NEC*, the GFPD requirement was extended to all PV systems with a few minor exceptions.

In a manner similar to other requirements in the *NEC*, there is no specific mention of how to implement the requirement. It should also be noted that neither is there any specification on the magnitude of the ground-fault current nor an exemption for grounded conductor ground faults.

Most currently available inverters, both stand-alone and utility-interactive, use a transformer that isolates the DC grounded circuit conductor (usually the negative) from the AC grounded circuit conductor (usually the neutral). With this transformer isolation, the DC side of a PV system may be considered similar, but not identical, to a separately derived system and, as such, must have a single DC bonding connection (DC system bonding jumper) that connects the DC grounded circuit conductor to a common grounding point where the DC EGCs and the DC GEC are connected. Like grounded AC systems, only a single DC system bonding connection is allowed. If more than one bonding connection were allowed on either the AC or DC side of the system, unwanted currents would flow in the EGCs, which violates *NEC* Section 250.6.

Due to the above isolation and the fact that the DC circuits of the PV system are bonded to ground in one place only, there will normally be no current (only leakage current) flowing to ground. Today, a typical GFPD detects excessive current flowing to ground using an OCPD or current sensor placed in the DC system bonding conductor or a differential current sensor placed so that it senses the difference between the PV+ and PV- currents coming from the PV array to the inverter.

Currently, GFPDs are available as both separate devices for adding to stand-alone PV systems and as internal circuits integrated into most utility-interactive inverters or other PV equipment. The GFPD that monitors current in the DC system bonding jumper often serves as that connection and opens the connection when a ground fault is detected. In other designs, the DC system bonding jumper is not opened to interrupt the fault currents, and the GFPD acts by disconnecting both of the current-carrying conductors from the PV array.

In any ground-fault scenario on the DC side of a grounded PV system, ground-fault currents from any source (PV modules or batteries in stand-alone systems) must eventually flow through the DC system bonding jumper on their way from the energy source through the fault and back to the energy source. This includes single ground faults involving the ungrounded conductor or the grounded conductor faulting to ground. In grounded conductor ground faults, the fault path creates parallel paths for the grounded conductor currents—one path through the grounded conductor and one path through the fault path. The fault path current will flow through the DC bonding connection. Double ground faults, either in a single source or output circuit or in a separate source or output circuit, are beyond the ability of any equipment to deal with at this time, and are not addressed in the *NEC* or in UL standards.

To meet the *NEC* Section 690.5 requirements, a GFPD using the DC system bonding jumper has a 0.5- to 5-amp overcurrent device installed in that bonding connection. When the DC ground-fault currents exceed the trip current rating of the device, it opens. By opening, the overcurrent device interrupts the ground-fault current as required in *NEC* Section 690.5. If a circuit breaker serves as the overcurrent device, the tripped position of the breaker handle provides the indicating function. When a fuse is used, an additional electronic monitoring circuit in the inverter provides an indication that there has been a ground fault. In some cases, a mechanical blown fuse indicator activating an associated switch provides a blown fuse indication. The indication function is also an *NEC* 690.5 requirement. Automatic resetting is not allowed for these devices.

In some designs, in which the GFPD uses a circuit breaker as the sensing device, an additional circuit breaker may be mechanically connected (common handle/common trip) to the sensing circuit breaker. These types of GFPDs are commonly found in stand-alone PV systems. This additional circuit breaker, usually rated at 100 amps and used as a switch rather than an overcurrent device, is connected in series with the ungrounded circuit conductor from the PV array. Multiple poles of a single circuit breaker can be used to simultaneously disconnect different subarrays of the same system. In this manner, when a ground fault is sensed and interrupted, the added circuit breaker(s) disconnects the PV array from the rest of the circuit, providing an additional indication that something has happened that needs attention.

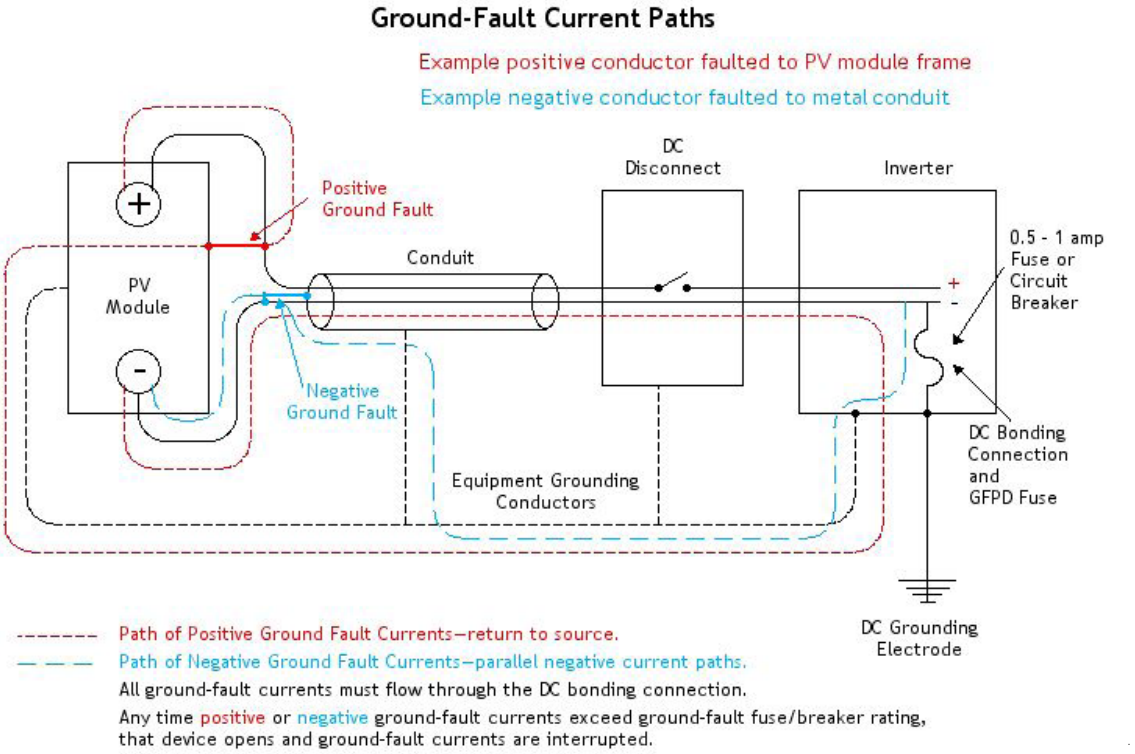
Even if the GFPD uses an additional circuit breaker pole in the ungrounded PV conductor, that circuit breaker may not be used as the PV disconnect because in normal use, turning off this breaker would unground the system and this is undesirable and could be unsafe in non-fault situations. Furthermore, such an operation is prohibited in Section 690.13 of the *NEC*. In the GFPD installed in utility-interactive inverters using a fuse as the sensing element, the electronic controls in the inverter indicating that there has been a fault also turn the inverter off and provide an indication that the fault has occurred.

It should be noted that the DC GFPD in many stand-alone systems detects and interrupts ground faults that occur anywhere in the DC wiring, and the GFPD may be located anywhere in the DC system. Because the normal location for the DC bonding connection is at or near the DC disconnect, this bonding connection is usually made at the DC power center where there is ready access to the DC GEC connection point. Utility-interactive inverters or DC power centers on stand-alone systems are the most logical places for GFPDs. There is no significant reason to install them at the PV module location. This configuration would increase the length of the DC GEC and complicate its routing. To achieve significant additional safety enhancements would require a GFPD at every module. Equipment to do this does not exist and there are no requirements for such equipment.

GFPD devices using differential current measurements or other sensing techniques could be mounted at the inverter input or in PV DC combiners. When mounted in the DC combiner, they could more readily isolate sections of a faulted array while leaving the non-faulted sections in an operational state.

Figure 3 shows both positive (red) and negative (blue) ground faults and the paths that the fault currents take in a GFPD monitoring the current in the DC system bonding jumper. This particular system is a grounded system and the negative conductor is the grounded circuit conductor. As noted above, all ground-fault currents must pass through the DC system bonding connection where the GFPD sensing device is often located.

Figure 3: Ground-Fault Current Paths for Different Fault Conditions



These devices are capable of interrupting ground faults occurring anywhere in the DC system, including faults at the PV array or anywhere in the DC wiring from the PV module to the inverter and to the battery in stand-alone systems. Systems that have isolation components such as some charge controllers or DC-to-DC converters may have a more limited view of fault locations. All of this can be done from many possible locations in the DC circuit. Including these GFPDs on all PV systems reduces the potential for fires.

Keeping the PV source and output conductors outside of a dwelling until the point of first penetration and requiring the readily accessible DC disconnect at this point also enhances the safety of the system. See Section 690.14 of the *NEC* for details. The 2005 *NEC* and subsequent editions of the *NEC* allow conductors in metallic raceways to be routed inside the structure (690.31[E]). The use of metallic raceways for the DC source and output circuits will facilitate ground-fault detection if the conductors in those grounded conduits fault to the conduit.

During a ground fault, if the DC system bonding connection is opened or all conductors are disconnected from a faulted circuit, and if the ground fault cures itself for some reason (e.g., an arc extinguishes), the faulted circuit in the DC system remains ungrounded until the GFPD system is reset. An ungrounded conductor-to-ground fault may allow the grounded conductor (now ungrounded) to go to the open-circuit voltage with respect to ground. This is addressed by the marking requirements of Section 690.5(C). A very high value (>50k) resistor is usually built into the GFPD and this resistor bleeds off static electric charges and keeps the PV system loosely referenced to ground (but not solidly grounded) during ground fault actions. The resistor value is selected so that any fault currents still flowing are only a few milliamps and are too low to be a fire hazard.

But Problems Still Exist. Although the *NEC* and UL standards require that ground faults be detected, some implementations of the GFPD may not recognize ground faults in all circuits throughout the PV array. Active analysis of these issues is ongoing and UL Standards and/or the *NEC* will be modified to rectify this problem, which is addressed in the following paragraphs.

During the daily cycle of zero current to rated current in bright sun, an ungrounded conductor ground fault will usually source enough current to activate the ground-fault detector. The detection current for the ground-fault system as currently implemented must be set high enough (0.5 to 5 amps) to prevent nuisance trips due to expected and normal leakage currents. These leakage currents increase in wet weather, with array size, and as the array ages. However, lower currents (below the detection value) that are associated with grounded conductor and ungrounded ground faults will go undetected. In the case of grounded conductor ground faults, the faults may exist for significant periods of time before being detected or found because there is typically no loss of performance because the currents from the source still get to the inverter. A ground fault in an ungrounded conductor that is below the detection level of the GFPD may be sensed as a loss of power in that circuit, however, provided that the data monitoring system has sufficient sensitivity and granularity.

If a grounded conductor ground fault exists and a second ground fault occurs in an ungrounded conductor, the GFPD will activate, but this action may force high fault currents through the grounded conductor ground fault. This grounded conductor fault path may be incapable of withstanding these high currents and pose a fire hazard. See the Solar ABCs paper on the *Ground-fault Protection Blind spot* (Brooks, 2012). Second ungrounded conductor ground faults in a system with an initial ungrounded conductor fault can be treated as an independent event and usually will not interact with the first fault. The exception is that the two ground-fault currents may add to a sufficient value to be sensed by the GFPD.

Ungrounded Systems. Section 690.35 of the *NEC* also requires ungrounded systems to have a GFPD. These detection systems are mainly electronic in nature and may not have the issues of the GFPD on grounded systems. These systems have to operate with leakage currents and impedances and those factors will change with system age and environmental conditions. The most common GFPD approach in ROW is electronic impedance measurements between array conductors and ground, a strategy that has proven effective. Monitoring and tracking the impedances over time may allow ground faults to be more readily detected in the presence of time varying leakage currents. With equipment modifications and redesign, and when implemented prior to exporting current from the array, such devices could be applied to existing grounded PV systems.

THE CONNECTION TO EARTH

The grounding electrode is the final connection to the earth and carries currents from lighting-induced surges as well as from possible cross connections with other electrical power systems to the earth. The *NEC* discusses a number of different metallic materials and components that may be used as grounding electrodes as well as various restrictions on their installation. Using more than one of these electrodes (encouraged by the *NEC*) forms a grounding electrode system.

Grounding electrodes include rods, pipes, plates, rings, concrete encased electrodes, building steel, and other devices. Rod-type electrodes must be stainless steel or copper or zinc coated steel and may use other materials when certified/listed.

The resistance from the grounding electrode to earth must be 25 ohms or less (250.53[A][2]). If this criterion is not met, an additional grounding electrode must be added more than six feet away to form a grounding electrode system. There is no requirement to measure this resistance to ground and it is rarely measured because it requires specialized equipment. For that reason, many local codes, particularly in the dry Southwest, require that two grounding electrodes always be installed.

GEC Size. The apparent quality of the grounding electrode connection to earth, all other things being equal, appears to be the rationale for sizing the GEC. The better the presumed contact with earth, the larger the required GEC. Section 250.166 establishes the sizes for a DC GEC and 250.66 establishes the size for an AC GEC. Both appear to require increased sizes for the grounding electrodes that provide the better contact with earth.

No Fault Currents. It should be noted that ground-fault currents do not normally travel through the GEC to the grounding electrode and then to the earth. These ground-fault currents typically flow through the equipment grounding system and the circuit conductors. An exception occurs when a grounding electrode system involves building steel where multiple conductive paths in the equipment grounding system and grounding electrode system may be involved with fault currents.

UTILITY VS *NEC* REQUIREMENTS

The *NEC* covers the premises wiring requirements up to the "service point," which is an NEC definition for the point at which utility requirements end and *NEC* requirements begin. Utility electrical installation requirements are established by the *National Electrical Safety Code (NESC)* (a registered trademark of the Institute of Electrical and Electronic Engineers [IEEE]) and various other IEEE standards.

The three-phase multi-grounded system is referenced in both the *NESC* and the *NEC*. The *NESC* sets the ground rules for practical safeguarding of persons during the installation, operation, or maintenance of electric supply and communication lines and associated equipment. The *NESC* contains the basic provisions that are considered necessary for the safety of employees and the public under the specified conditions.

In the grounding arena, if the utility has grounded any of the service conductors in their distribution system (usually at the local distribution transformer secondary), the *NEC* requires that these grounded conductors be connected to earth (grounded) again at the service disconnect. There is typically no EGC between the premises electrical system and the utility electrical system. In some cases, like a three-wire delta service, there may not even be a grounded circuit conductor such as the grounded neutral conductor on a four-wire wye service.

On larger systems, particularly those with an interface at medium voltage, utility grounding requirements may be applicable to the grounding methods used at the service entrance. *IEEE 142—The Green Book* (IEEE, 2007) provides some of the highly technical explanations for grounding these types of systems and some utilities may require that these practices be followed before allowing the PV interconnection.

Acronyms

AC	alternating current
AHJ	authority having jurisdiction
ANSI	American National Standards Institute
AWG	American wire gauge
DC	direct current
EGC	equipment grounding conductor
GEC	grounding electrode conductor
GFCI	ground-fault circuit interrupter (AC Systems)
GFPD	ground-fault protection device
Hz	hertz
IEEE	Institute of Electrical and Electronic Engineers
I_{sc}	short circuit current
NEC	*National Electrical Code*
NESC	*National Electrical Safety Code*
NFPA	National Fire Protection Association
NRTLs	Nationally Recognized Testing Laboratories
OCPD	overcurrent protective device
OSHA	U.S. Occupational Safety and Health Administration
ROW	rest of world
UL	Underwriters Laboratories

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Fire Classification Rating Testing of Stand-Off Mounted Photovoltaic Modules and Systems

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August 2013

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EXECUTIVE SUMMARY

The year 2013 marks a significant change for the fire classification rating approach for roof mounted stand-off photovoltaic (PV) modules and panels evaluated in accordance with American National Standards Institute/Underwriters Laboratories, Inc. (ANSI/UL) 1703, *Standard for Safety for Flat-Plate Photovoltaic Modules and Panels.* Prior to 2013, a PV module manufacturer could receive a fire classification rating based on tests of the module or panel alone. After the 2013 changes to ANSI/UL 1703, the fire classification rating approach takes into account the module or panel in combination with the mounting system and the roof covering products over which it is installed. The proposals that led to these changes were an outgrowth of research tests conducted and broad stakeholder forums held through a partnership between UL and the Solar America Board for Codes and Standards (Solar ABCs).

Throughout this report, ANSI/UL 1703-2012 (ANSI/UL, 2002) refers to versions of UL 1703 with a revision date of May 8, 2012 or earlier. ANSI/UL 1703-2013 refers to the new edition of UL 1703 that incorporates the new fire classification test described in this report.

Around 2009, it became apparent that fire and code officials and the solar industry had concerns about the installation of lesser class-rated PV modules (Class C) over higher class-rated roofs (Class A). Although both roof covering materials and PV modules received fire class ratings, little work had been done to investigate the interactions between them when systems composed of PV modules mounted in stand-off configuration over roofing systems are exposed to burning materials or flame. Specifically, it was necessary to investigate whether and how PV modules with Class B or C fire ratings may adversely affect the performance of Class A rated roofing systems. To investigate these concerns, Solar ABCs and UL conducted extensive tests on various combinations of PV designs and roof coverings, and explored some mitigation techniques.

During early research testing, various spread of flame test experiments were performed with Class A and Class C rated PV modules mounted in combination with Class A roof products and systems. The results in all cases showed flame propagation well beyond the ANSI/UL 1703-2012 Class A requirement of six feet within a fraction of the typical test time duration. Experiments were also performed to examine a burning item coming to rest between the PV and the roof, or the ignition of accumulated leaves or debris. Testing showed that Class A rated PV modules mounted at a typical five-inch gap height did not comply with Class A requirements when the burning brand was placed on the roof below the modules. When this test was performed using Class C modules, the test results were inconclusive. Finally, initial testing found mitigation techniques that showed promise in preventing the degradation of roof covering fire class rating by rack-mounted PV modules.

The research tests demonstrated that fire class rating of the PV module alone determined according to ANSI/UL 1703-2012 may not predict the fire performance of the PV module, mounting system, and roof assembly as a system. From a safety perspective, the objective of the work turned towards promoting stand-off-mounted PV systems with improved performance and developing a system-based test that would differentiate high performing from low performing designs. Thus, the stakeholders and investigation team decided to pursue the development of a new fire classification test for the PV module, the mounting components, and the roof assembly as a system.

During the steps towards development of a new fire classification test, the team considered the real world scenario in which the roof ignites first and then the flames develop and migrate underneath the PV panel to present a fire exposure challenge to the PV system. This concept of first to ignite, second to ignite sequence is well established in the fire protection community, and was proposed as the best way to properly evaluate a PV module in the presence of a roof covering. In all the research tests prior to this concept, the PV module was installed in a position where both the roof and the module were subjected to the ignition source with zero offset or with only modest offset distances (24 inches or less) from the flame source. At the beginning of these tests, the test flame was already extending well into the gap between the module and the roof. However, with a first to ignite, second to ignite test, the PV is installed for test with a setback such that the roof covering ignites first, the fire propagates along the roof, and then the PV module is exposed. This concept was tested in a number of validation tests.

These experiments led to a new fire classification test, which is a significant change from the previous PV module fire classification test procedure. In the new procedure, the module is tested mounted over representative roof covering systems and the performance of the entire system is the basis for the fire classification rating of the PV module with mounting system. In this manner, the new PV fire classification test provides a more useful rating than the previous PV module-only rating test.

The new requirements in ANSI/UL 1703-2013 include an optional characteristic testing of PVs, tested alone in a similar manner to ANSI/UL 1703-2012. This characterization was maintained because this information can prove useful in demonstrating grouping of PVs into “types” in an effort to satisfy the ANSI/UL 1703-2013 requirements for the classification rating as a system.

The new fire classification rating tests in ANSI/UL 1703-2013 involve the combination of the module or panel, the mounting system, and the roof covering system. Because each of these three components has many products in the marketplace, testing every possible combination of the three components could mean thousands of required tests. This is not practical and could stifle market innovation. In response, a number of considerations and provisions were written into the new standard to reduce the number of required tests. In addition, Solar ABCs, UL, industry, and stakeholders continue to explore and validate industry-wide solutions that may satisfy the new, revised ANSI/UL 1703-2013 fire classification requirements in an effort to reduce the industry’s testing burden.

Solar ABCs is a collaborative effort among experts to provide coordinated recommendations to codes and standards-making bodies for existing and new solar technologies. UL provides safety and performance testing and product certifications for thousands of materials and products. UL is also a leading safety standard development organization. UL was a pioneer in the evaluation and testing of roof covering materials (e.g., shingles) and PV modules.

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Solar America Board for Codes and Standards

The Solar America Board for Codes and Standards (Solar ABCs) is a collaborative effort among experts to formally gather and prioritize input from the broad spectrum of solar photovoltaic stakeholders including policy makers, manufacturers, installers, and consumers resulting in coordinated recommendations to codes and standards making bodies for existing and new solar technologies. The U.S. Department of Energy funds Solar ABCs as part of its commitment to facilitate widespread adoption of safe, reliable, and cost-effective solar technologies.

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Acknowledgment

This material is based upon work supported by the U.S. Department of Energy under Award Number DE-FC36-07GO17034. This work was funded by the DOE Office of Energy Efficiency and Renewable Energy.

TABLE OF CONTENTS

DISCLAIMER 2

EXECUTIVE SUMMARY 3

AUTHOR BIOGRAPHIES 5

SOLAR AMERICA BOARD FOR CODES AND STANDARDS 6

ACKNOWLEDGMENT 6

BACKGROUND ON FIRE CLASSIFICATION RATING OF PV MODULES AND SYSTEMS 8

TESTS TO DEVELOP AND VALIDATE NEW FIRE CLASSIFICATION RATING TEST 12

- Burning Brand Tests Between Module and Roof 12
- Characterization of Photovoltaic Materials—Critical Flux for Ignition and Propagation 13
- Test Concept of First to Ignite, Second to Ignite 15
  - *Steep Slope Results* 16
  - *Low Slope Results* 17
  - *Summary and Findings* 18
  - *Recommendations* 19

NEW FIRE CLASSIFICATION TEST PROCEDURE 20

- Concerns About Multiple Configurations 20
- Description of Proposed Test Procedure 20
  - *PV Module or Panel Characterization* 20
  - *System Tests* 21
  - *Spread of Flame on Top Surface* 22
  - *Spread of Flame at Roof and Module or Panel Interface* 22
  - *Burning Brand on Surface Over Representative Steep Sloped Roof* 22
  - *Burning Brand Between Module or Panel and Representative Steep Sloped Roof* 22

Considerations for UL 2703 22

Industry Solutions 23

New Burner 23

CONCLUSIONS 24

ACRONYMS 25

REFERENCES 26

Background on Fire Classifications Rating of PV Modules and System

Roofing systems undergo a suite of tests described in Underwriters Laboratories (UL) 790—*Tests for Fire Resistance of Roof Covering Materials,* the test standard that determines the fire resistance properties of roofing. All roofing systems undergo these tests as required by local and model U.S. building codes. Roofing systems that demonstrate the highest resistance to ignition, burn through, and flame spread receive a Class A rating. Materials with lesser performance receive a Class B or C rating.

PV modules undergo safety testing to another standard, American National Standards Institute (ANSI)/UL 1703—*Standard for Safety for Flat-Plate Photovoltaic Modules and Panels* (ANSI/UL, 2002). Although this standard describes a suite of tests designed to stress the module physically, environmentally, and electrically, it also describes tests that result in a determination of a fire rating for each photovoltaic (PV) module or system. In ANSI/UL 1703-2012 and earlier versions, two tests were required, spread of flame and burning brand.

The spread of flame test applies a natural gas fueled flame and measures the potential for flames to spread across the surface. The burning brand test measures the potential for fire to penetrate from outside a roofing material (or, in the case of UL 1703-2012 tests, a PV module). The source of fire is a burning brand, a measured stack of dry wood that is ignited and burns with known properties.

These tests are a subset of UL 790 tests and resulted in a fire class rating for the module (Class A, B, or C). ANSI/UL 1703-2013 is the new version of this standard that includes the new fire classification test described in this report. The ANSI/UL 1703-2013 tests result in a system fire class rating for the module, mounting system, and roof covering (Class A, B, or C).

As a result of catastrophic wildfires, many jurisdictions, especially in California, increased the fire classification rating requirements for roof coverings. Where a Class B or C roof covering may have previously been allowed, many jurisdictions increased the requirement to a Class A roof covering. When presented with applications for rooftop solar installations, these jurisdictions began to question whether lesser class rated PV modules (Class C) installed over higher class rated roofs (Class A) would adversely affect the performance of Class A rated roofing systems. At this time, most PV modules were rated Class C.

When directed to UL's *Online Certification Directory* (White Book)(UL, 2007), the following provided guidance:

> Installation of modules on or integral to a building's roof system may or may not adversely affect the roof-covering materials' resistance to external fire exposure if the module has a lesser or no fire-resistance rating. Roof-covering materials will not be adversely affected when the modules have an equal or greater fire-resistance rating than the roof-covering material.

However, there was still ambiguity in the *Certification Directory* statement, so the solar industry and fire and code officials set out to clarify concerns about the most common residential PV roof installation—Class C rated PV modules mounted over Class A rated roofs. This effort illuminated the fact that there was a lack of fire test results on systems including PV modules in roof-mounted configurations. Industry representatives turned to UL to assist in bringing clarity to this concern.

Although roof covering materials and PV modules both received fire class ratings, little work had been done to investigate the interactions that may occur between them when burning materials or flame are imposed on systems composed of PV modules mounted in stand-off configuration over roofing systems. Specifically, it was necessary to investigate whether and how PV modules with Class B or C fire ratings may degrade the fire-resistance properties of Class A rated roofing systems using standard flammability test procedures and methods in a qualified laboratory. With funding from the U.S. Department of Energy, UL and the Solar America Board for Codes and Standards (Solar ABCs) developed a test plan to answer these questions.

In the Summer of 2009, Solar ABCs, in partnership with UL, designed and conducted specific tests to characterize the effects of stand-off mounted (elevated and parallel to roof surface) PV modules on the fire rating of Class A rated roofing systems. Staff members of UL's Corporate Research Division in Northbrook, Illinois, conducted all tests with assistance from representatives of Solar ABCs.

The tests included the "burning brand" and the "spread of flame" tests normally conducted on PV modules during ANSI/UL 1703-2012 certification of all PV modules, but with a major difference. During ANSI/UL 1703-2012 certification testing, fire and burning materials were applied to the top surface of the PV module only. The tests conducted for this study were designed specifically to impose fire between the module and roof covering (see Figure 1). Therefore, unlike ANSI/UL 1703-2012, which evaluates the properties of a PV module in isolation, the current tests were conducted to examine modules and roof coverings as a system when exposed to fire. Tests were designed to use the methods of UL 790 to evaluate different combinations of modules, stand-off heights, and roofing materials. These tests are reported in a Solar ABCs Interim Report (Rosenthal et al., 2010) and several UL Research Reports (Backstrom & Tabaddor, 2009a; Backstrom & Tabaddor, 2009b; Backstrom & Sloan, 2012a; Backstrom & Sloan, 2012b, Backstrom & Sloan, 2012c, Backstrom & Sloan, 2012d; Backstrom & Sloan, 2012e; Backstrom, 2013).

Figure 1. Example spread of flame test (this test is non-combustible roof with a simulated non-combustible PV module with 0-inch setback and a 10-inch gap.

The tests showed that the current fire classification rating of a module or panel may not in all cases predict the fire performance of the system including the module or panel, the mounting system, and the roof covering material. The results of testing demonstrated that any panel (even a noncombustible one) mounted at a range of gap heights (stand-offs) typical of many PV arrays will increase the temperature and heat flux present at the roof surface during the spread of flame test. The increased temperature and heat flux are the result of a "channeling effect" between the PV and the roof, through which the panel holds hot gases and flame close to the roof surface, not allowing them to dissipate as they do when not confined.

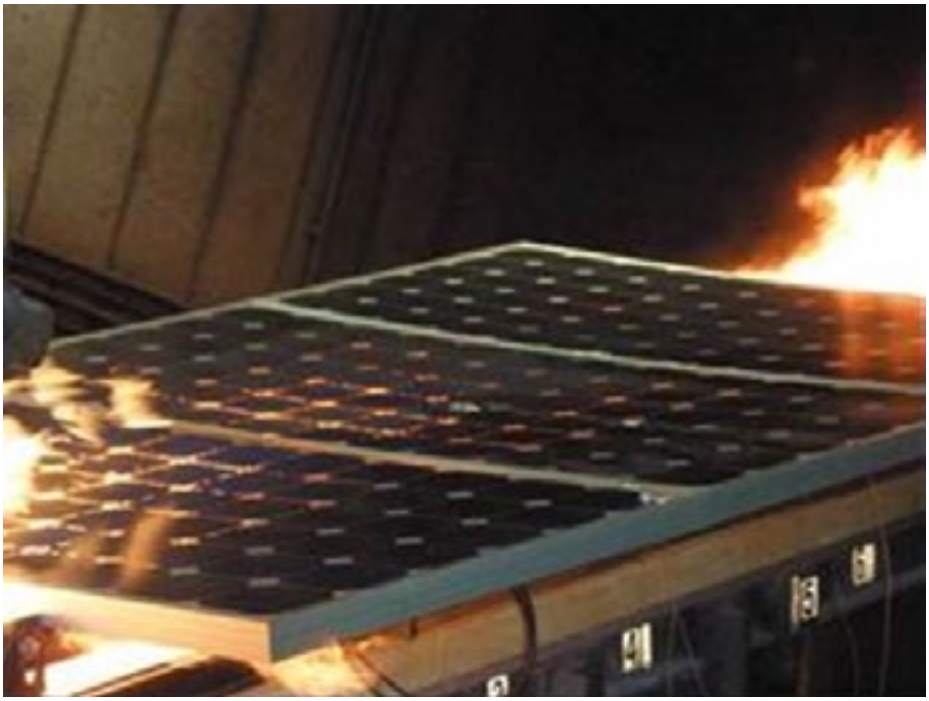

Figure 2. Spread of Flame Test showing failure to meet Class A requirements.

As a result of this "channeling effect," PV modules of any fire rating (Class A or C) mounted in a five-inch stand-off configuration will hold sufficient heat against the roof surface such that previously Class A rated roof coverings will no longer meet the Class A requirements during the UL 790 spread of flame test. The "channeling effect" shows the need for a systems approach to fire testing. Testing also determined that Class A rated PV modules mounted at a five-inch gap height prevented Class A rated roof coverings from meeting the Class A requirements of the burning brand test when the brand was placed on the roof below the modules, simulating a burning item coming to rest between the PV and the roof or the ignition of accumulated leaves or debris. This work will be discussed in further detail in the Burning Brand Tests Between Module and Roof section. When this test was performed using Class C modules, the test results were inconclusive. Finally, initial testing found mitigation techniques that show promise of preventing the degradation of roof covering fire class rating by rack-mounted PV modules. After completing this round of research, Solar ABCs and UL convened several meetings with a cross section of volunteer scientists and engineers from the PV industry, the enforcement community, other testing laboratories, and the National Institute of Standards and Technology.

From a safety perspective, the goal is that the installation of a stand-off mounted PV module and its mounting system does not degrade the fire class rating of the roof assembly. As the fire class rating of the PV module (determined according to ANSI/UL 1703-2012) is not a predictor of whether or not the fire class rating of the PV module and roof assembly as a system is changed from the fire classification rating of the roof assembly, additional work was required. In response, the stakeholders and investigation team decided to pursue the development of a new fire classification test for the PV module and roof assembly as a system.

TESTS TO DEVELOP AND VALIDATE NEW FIRE CLASSIFICATION RATING TEST

Burning Brand Tests Between Module and Roof

The burning brand test conducted in UL 790 and ANSI/UL 1703 is intended to evaluate roofing assemblies to resist the penetration of fire through the assemblies into spaces underneath, such as a cockloft or attic. There was general agreement that the burning brand test should continue to be conducted with the appropriate fire classification brand placed on top of the module and failure determined by whether the fire burns through the roof deck, as defined in UL 790.

However, the team considered the real world scenario of burning items coming to rest between the PV and the roof or the ignition of accumulated leaves or debris. This issue of a test with the burning brand placed between the module and the roof proved more controversial and warranted additional test work.

The objective of this set of experiments was to demonstrate the burning behaviors of the standard Class A and C roofing brands, as well as common materials that may collect between the PV modules and the roof surface, represented by excelsior (wood wool) and leaves. Temperatures of a noncombustible roof deck were measured directly under the burning item or material to illustrate the heat transfer to roofing materials (see Figure 3). In addition, the weight of the burning item or material and the peak heat release rate were also measured. These data were provided to contrast the different fuel packages. These experiments are described in detail in a UL research report (Backstrom & Sloan, 2012a).

Figure 3. Experimental setup with leaf debris over noncombustible deck.

The following is a summary of the results:

- Under similar wind conditions of 700 feet per minute (fpm), the Class A brand developed a significantly greater amount of energy than the Class C brand both in peak and total.
- The leaf debris and excelsior generated substantially less energy than the Class A brand, but significantly greater than an individual Class C brand. One significant challenge with the use of leaf debris or excelsior is an expected variation of energy generated due to the nature of the material.

Overall, the heat release rate and heat transfer to the roof surface of Class A and Class C brands did not demonstrate a direct correlation to common materials that may collect between PV modules and the roof surface, such as leaf debris and excelsior (wood wool). The Class A brand yielded significantly greater heat transfer than the leaf debris and wood excelsior, and the Class C brand yielded significantly less heat transfer than the leaf debris and wood excelsior. Although the Class B brand was not included in the experiments, the conclusion of these experiments is that the representation of materials likely to collect between the PV module and the roof surface is closest to the Class B brand in terms of heat release and heat transfer to the roof surface. Based on these experiments, the new standard test (in ANSI/UL 1703-2013) includes a Class B brand for the tests between the module and the roof.

Characterization of Photovoltaic Materials—Critical Flux for Ignition and Propagation

As the work began to develop a fire classification rating test for PV and roofing systems, attendees at stakeholder meetings as well as members of the UL 1703 Standards Technical Panel (STP) expressed concern about the number of tests that would be required to evaluate a seemingly insurmountable number of combinations of PV modules or panels, mounting systems, and low and steep slope roof systems and products. Although roof coverings may generally be grouped into low and steep sloped roofs, the number of manufacturers and types of roofing products are more than what can be reasonably evaluated by a PV manufacturer.

These experiments examined possible similarities of roofing materials and PV modules in an effort to extend PV/roofing system evaluation to a large number of roofing types while minimizing the amount of testing required. Critical flux for ignition was the parameter chosen to compare the different materials. Critical flux is a fundamental fire property of a material and is defined as the minimum level of incident radiant flux energy required for ignition, expressed as energy per unit area (kilowatts per square meter [kW/m^2] or watts per square centimeter [W/cm^2]). A UL Research Report describes these tests in detail (Backstrom & Sloan, 2012b).

The products tested were PV modules and roofing product samples either donated by industry or purchased from local retailers. The PV modules were metal framed glass on polymer design, representative of Class C fire classification rating (ANSI/UL 1703-2012 standard). The roofing products consisted of Class A steep slope 3-tab and architectural (laminate) roof shingles, base and cap sheets, ethylene propylene diene monomer (EPDM) and fire retardant (FR) EPDM membranes, and polyisocyanurate insulation boards. The samples tested included:

- composite or “stacks” cut from PV modules consisting of glass, encapsulant, and cell and backplane layers (three manufacturers),
- three-tab shingles (three manufacturers),

- architectural shingles (three manufacturers),
- base sheet (one manufacturer),
- cap sheet (two manufacturers),
- EPDM membrane (one manufacturer),
- FR EPDM membrane (one manufacturer),
- insulation board (one manufacturer), and
- FR insulation board (one manufacturer).

The experimental plan originally was designed to obtain the value of critical flux for ignition using the floor and radiant panel (FARP) apparatus, the lateral ignition and flame travel (LIFT) apparatus, and, finally, the cone calorimeter apparatus. The plan was to compare measured values from the different tests for the same roofing or PV product to gain an understanding of the influence of the test method and fixture on critical flux values.

Critical flux measurements are obtained directly from the FARP and LIFT experiments using the ASTM E648 and E1321 test protocols, respectively. In both of these test protocols, the flame front or propagation along the sample surface is directly related to the incident radiant flux exposure during the test. A calibration is conducted to establish the relationship between heat flux and distance. The critical flux is then determined from the point at which the flame front progresses. In this work, neither the FARP or the LIFT apparatus successfully determined critical flux values for either roofing or PV materials.

The cone calorimeter protocol (see Figure 4) using the ASTM E1354 procedure does not determine critical flux directly as a reported result from the test protocol. Rather, the test apparatus may be used to conduct experiments at multiple heat flux exposures in order to derive the critical flux by plotting heat flux vs. ignition times. This technique was used to develop critical flux values for both roofing and PV materials.

Figure 4. Cone calorimeter test apparatus (ASTM 1354).

An analysis of the data generated by the experiments carried out in this study point to the following key findings:

- The critical flux values for most of the roofing products was greater than the 14 kW/m^2 exposure measured on the surface of a noncombustible deck without PV. The critical flux values for all of the roofing products was less than the 41 kW/m^2 exposure measured on the surface of a noncombustible deck with PV installed with a five-inch gap.
- The critical flux for ignition of low slope roof products was found to be generally consistent, as was the critical flux for ignition of steep slope roof products.
- Crystalline silicon PV modules ignite at nearly identical critical flux values.

These test results supported the premise that, within limits, groupings of low slope roofing products, steep slope roofing products, and certain types of PV modules could be "represented" in a fire response test with an expectation of similar test results. This conclusion would later prove extremely helpful as the team began development of the new test protocol.

Test Concept of First to Ignite, Second to Ignite

To date in the research, almost all PV and roof system combinations were non-compliant when using the traditional UL 790 Class A methods and requirements. Although the critical flux experiments discussed above demonstrated that certain products could be grouped, the team was still challenged to develop a new test that would differentiate PV system performance. The concept of first to ignite, second to ignite items was proposed as the best way to properly test the PV module in the presence of a roof covering.

In all the tests previously reported, the PV module was installed in a position so that both the roof and the module were subjected to the ignition source with zero offset or with only modest offset distances (24 inches or less) from the flame source. At the beginning of the test, the test flame is already extending well into the gap between the module and the roof. However, the broad group of industry and stakeholders began to consider the likely real world scenario in which the roof ignites first and then the flames develop and migrate under the PV, presenting a typical fire exposure challenge to the PV, its mounting system, and the roof covering underneath. This approach became known as the first to ignite, second to ignite test, in which the roof covering is ignited and then that flame is used to test the PV module. This same concept is used in testing other products, for example, furniture (California Department of Consumer Affairs, 1991), mattresses (CPSC, 2006), and fuel packages (NFPA, 2013).

A series of experiments evaluated the first to ignite, second to ignite concept for testing a PV system, including a module or panel, mounting system, and roof covering (Backstrom & Sloan, 2012d). In these tests, a UL 790 ignition source created flames on a representative roof section and then the test engineers observed the propagation of flames underneath the PV module being tested.

Figure 5. Example experiment illustrating first to ignite, second to ignite concept with 48-inch offset (low slope roof with low slope FR EPDM, noncombustible PV surrogate, five-inch gap)

Commercially available PV modules and roofing product samples were either donated by industry or purchased from local retailers. The PV modules were an ANSI/UL 1703-2012 Class C fire rated metal framed glass on polymer design. A surrogate representation of a PV module was simulated using a noncombustible sheet for some experiments.

The UL 790 (ASTM E108) Class A rated roof deck assemblies consisted of:

- three-tab shingles with 30 pound felt underlayment over nominal ½-inch plywood (Note: three manufacturers of shingles were used in the experiments); and
- 60 mil low slope FR EPDM over four-inch-thick polyisocyanurate insulation board mechanically fastened to a non-combustible deck.

Steep Slope Results

Ten experiments were conducted on steep slope roofs constructed using Class A rated, three-tab shingles produced by three different manufacturers. Maximum flame spread distances and the corresponding time at which they occurred for the various steep slope roof assembly experiments were recorded. Two baseline experiments without PV modules present were conducted on the shingles from manufacturer one, and single baseline experiments were conducted on shingles from manufacturers two and three. All baseline experiments without PV modules demonstrated flame spread along the roof surface of approximately four feet (UL 790 Class A compliant).

When a noncombustible PV surrogate was installed at a gap height of five inches and an offset of 36 inches, the flame spread along the roof extended to four feet (Class A compliant). When a noncombustible PV surrogate was also installed at a gap height of five inches and an offset of 24 inches, the flame spread along the roof extended to eight feet (Class A noncompliant). These results showed that a noncombustible PV would likely pass at a 36-inch offset but likely fail at a 24-inch offset. This suggested that the 36-inch offset may be a critical, and therefore ideal, test condition for achieving passing or failing results based on product or system design.

Figure 6. Spread of flame test with steep slope roof and PV module, 36-inch offset, five-inch gap, and 0° inclination.

Two experiments were conducted with aluminum framed, glass on polymer PV modules installed at a gap of five inches, an offset of 42 inches, and parallel to the roof (0° inclination). For the experiment conducted with shingles from manufacturer one, the flame spread was three-and-a-half feet (Class A compliant), and for the experiment conducted with shingles from manufacturer three, the flame spread was four feet (Class A compliant).

Two additional experiments were conducted with the modules installed at an offset of 36 inches. The experiment conducted with shingles from manufacturer one developed a flame spread of four feet (Class A compliant), and manufacturer three's product developed a flame spread of four and a half feet (Class A compliant). These results validated that some designs would likely pass the steep slope condition without redesign.

Low Slope Results

Six experiments were conducted with low slope roofs. The baseline experiment without a PV module present demonstrated a maximum flame spread distance along the roof of approximately five feet, which is Class A compliant.

A noncombustible PV surrogate was installed at a gap height of five inches and an offset of 48 inches. The flame spread along the roof extended under the PV module and the total spread of flame along the roof was eight feet (Class A noncompliant). The same configuration, but with an offset of 52 inches, exhibited a flame spread of eight-and-a-half feet (Class A noncompliant).

A series of experiments were conducted with PV modules installed at a gap height of five inches. With the module installed at an offset of 48 inches and parallel to the roof (0° inclination), the flame spread extended to eight feet (Class A noncompliant). Another experiment was conducted with the module offset at 48 inches, but with the module installed at a slight angle to the roof (10° inclination) resulting in a flame spread of four feet (Class A compliant). A final experiment was conducted with two modules at an angle to the roof (10° inclination), the first offset 24 inches and the second spaced 12 inches from the first. Flame spread across the roof surface with both modules fully involved with flames extending beyond the deck (Class A noncompliant). These tests and results are described in detail in a UL Research Report (Backstrom & Sloan, 2012d).

UL ran a separate set of experiments to generate data on a 42-inch setback of the PV module on low slope roofs (Backstrom & Sloan, 2012e). Three experiments were conducted with aluminum framed glass on polymer PV modules installed at a gap height of five inches, an offset of 42 inches, and parallel to the roof (0° inclination). During two of the three experiments, the flame spread extended to a maximum of three and a half feet (Class A compliant). A third roof/PV experiment was conducted resulting in a flame spread of eight feet (Class A noncompliant). In this experiment, flames spread across the roof surface with both the module and the roof fully involved, and flames extending beyond the deck.

Summary and Findings

Low Slope:

- The low slope roof baseline experiment (no PV) exhibited a flame spread of 60 inches.
- A noncombustible representation of a PV module or a Class C PV module mounted parallel to and at an elevation of five inches above the roof and at offsets of 48 and 52 inches resulted in flame spreads in excess of Class A performance requirements.
- A PV module mounted at a slight inclination (10°) to and at an elevation of five inches above the roof and at a 48-inch offset did comply with Class A requirements.
- A single experiment conducted with two modules angled to the roof (10° inclination), the first offset 24 inches and the second spaced 12 inches from the first did not comply with Class A requirements.
- The overall results of low slope tests with the PVs present were fairly consistent with tests using a surrogate noncombustible PV.

Steep Slope:

- The steep slope roof baseline experiments (no PV) exhibited a flame spread of 48 inches.
- A noncombustible representation of a PV module mounted parallel to and at an elevation of five inches above the roof with an offset of 42 inches complied with Class A requirements.
- Two experiments conducted with PV modules mounted parallel to and at an elevation of five inches above the roof with an offset of 42 inches complied with Class A requirements.
- Two experiments conducted with PV modules mounted parallel to and at an elevation of five inches above the roof with an offset of 36 inches complied with Class A requirements.
- An additional experiment was conducted with a noncombustible sheet mounted parallel to and at an elevation of five inches above the roof with an offset of 24 inches and did not comply with Class A requirements
- The overall results of steep slope tests with the PVs present were fairly consistent with tests using a surrogate noncombustible PV.

Recommendations

Based on the research study findings, the repositioning approach of examining the first item ignited (roof) and then the second item ignited (PV), was a viable method for assessing the performance of a roof/PV combination. It was observed that this method was of such severity that currently commercially available PV Class C modules would likely have to be modified, or the installation details specified, in order to yield compliant results for both low and steep slope tests. It is important to note that the results of tests with the PVs present were fairly consistent with tests using a surrogate noncombustible PV.

Consequently, the UL Research Team as well as a focus group present to observe some of these tests supported the following recommendations and suggestions for proposed revisions to ANSI/UL 1703-2012:

Spread of flame tests to be conducted:

- individually, with the module mounted on a noncombustible deck and oriented such that the ignition flame is directed on the top surface of the module or panel;
- with the module installed on steep slope and low slope roofs as an assembly and oriented such that the ignition flame is directed into the interstitial space below the module and above the roof, the module or panel installation shall be installed:
    - o with 36 inches between the edge of the flame test apparatus and the edge of the PV mounting system for steep sloped roofs, and
    - o with 42 inches between the edge of the flame test apparatus and the edge of the PV mounting system for low sloped roofs.

NEW FIRE CLASSIFICATION TEST PROCEDURE

The proposed changes were put before the UL 1703 STP and underwent review, technical debate, and changes from the original proposal—all typical of most consensus standards development processes. The final result was a new fire classification test procedure (ANSI/UL 1703-2013), which is a significant change from the current PV module fire classification test procedure. In the new procedure, the module is tested mounted over representative roof covering systems and the performance of the entire system is the basis for the fire classification rating of the PV module with mounting system. With this approach, the new PV fire classification test is a measure of effects of the PV installation on the fire classification rating of the roof covering system and provides a more logical rating than the previous PV rating test.

Concerns About Multiple Configurations

The fire classification rating tests involve the module or panel, the mounting system, and the roof covering system. Because each of these three components has many products in the marketplace, testing every possible combination of the three components could mean thousands of required tests. This is not practical and could stifle market innovation. In response, a number of provisions were written into the new standard to reduce the number of required tests.

First, two representative roof covering systems were chosen—one for steep slope and one for low slope. Manufacturers must use these two representative roof covering systems for their tests.

Second, a type system was defined for PV modules. Types 1 and 2 modules have a tempered glass superstrate, polymeric encapsulant, polymeric substrate, and aluminum framing and meet minimum fire performance requirements. Type 3 modules or panels have tempered glass superstrate, polymeric encapsulant, tempered glass substrate, and no frame and meet minimum fire performance requirements. Additional types with different combinations of superstrate, encapsulant, substrate, and frame could be developed in the future. A test for one type module would apply to all other modules of the same type. Thus a mounting system manufacturer could test a Type 1 module with their mounting system and the results would apply to all other Type 1 modules with the same or similar installation instructions.

A module manufacturer may perform the module or panel characterization tests. Then a mounting system or module manufacturer performs the fire classification tests for a specific type of module or panel. Any other module or panel that meets the requirements for same type module or panel could receive the same fire classification rating. With this evaluation scheme, the required number of tests will be drastically reduced to a manageable number without excluding any products or system solutions from the marketplace.

Description of Proposed Test Procedure

PV Module or Panel Characterization

Initially, two characterization tests are described for PV modules and panels, tested independently of the mounting system. These tests are summarized in Table 1 and then each of the tests is described. A more detailed description including the actual requirements is included in ANSI/UL 1703-2013.

Table 1

Type Tests for Fire Performance of PV Modules or Panels Independent of Mounting System and Roof Covering

Test	Fire Performance Characteristics		
Spread of flame on top surface of module or panel	Flame spread less than 6 ft. in 10 minutes	Flame spread less than 8 ft. in 10 minutes	Flame spread less than 13 ft. in 4 minutes
Burning brand on surface of module or panel	A Brand	B Brand	C Brand
One test is required for each of the above required tests			

The spread of flame on top surface test is the same as the spread of flame test in ANSI/UL 1703-2012. The module or panel is mounted in the test apparatus such that the ignition flame is directed at the top surface of the module or panel. The flame spread is measured from the origin of the test flame apparatus.

The burning brand on surface of module or panel test is the same as the burning brand test in ANSI/UL 1703-2012. The module or panel fails the test if there are flaming or glowing brands blown off the test deck, the brand burns a hole in the module, or there is sustained flaming of the module or panel. The data from these characterization tests may be used towards certain tests required for the system fire classification rating.

System Tests

Five system tests are required to develop the fire classification rating for a PV module or panel with mounting system. These tests are summarized in Table 2 and then each of the tests is described. A more detailed description including the actual requirements is included in ANSI/UL 1703-2013.

Table 2

Required Tests for Fire Class Rating of PV Module or Panel With Mounting System in Combination With Roof Coverings

Test	Tests Over Representative Roof Coverings		
	Class A	Class B	Class C
Spread of flame on top surface of module or panel[a]	Flame spread less than 6 ft. in 10 minutes	Flame spread less than 8 ft. in 10 minutes	Flame spread less than 13 ft. in 4 minutes
Spread of flame at roof and module or panel interface over representative steep sloped roof	Pass	Pass	Pass
Spread of flame at roof and module or panel interface over representative low sloped roof	Pass	Pass	Pass
Burning brand on surface over representative steep sloped roof	A Brand	B Brand	C Brand
Burning brand between module or panel and representative steep sloped roof	Pass	Pass	Pass
[a] Requirement can be met with a type tested module or by performing the test on the top surface of a module or panel in the mounting system being qualified. For non-type tested products, the product must pass two consecutive tests for each required test.			
Two consecutive tests for each test must be passed unless not required by the terms of ANSI/UL 1703-2013, Sections 31.2.1.2, 31.2.2, or 31.2.3.			
For the purpose of ANSI/UL 1703-2013, Steep and Low Sloped Roof are defined in Section 31.2.1.1.			

Spread of Flame on Top Surface

This requirement can be met with either a type tested module or by performing the test on the top surface of a module or panel in the mounting system being qualified. For non-type tested products, the product must pass two consecutive tests for each required test.

Spread of Flame at Roof and Module or Panel Interface

This test measures the spread of flame in the interface between the module or panel, its racking system, and a representative roof system. The test is conducted over a representative steep sloped roof or a representative low slope roof, depending on the intended use of the module or panel. If installation is intended for both low and steep slope applications, then both tests must be conducted. The module is installed with an offset between the edge of the flame test apparatus and the edge of the PV mounting system. The offset distance is established as the average baseline of the low slope or steep slope roofing materials minus 12 inches, but no less than 36 inches. This application of the first item ignited, second item ignited concept is further described in the Test Concept of First to Ignite, Second to Ignite section. The system passes the test if the flame spread is less than six feet, measured from the origin of the test flame apparatus.

Burning Brand on Surface Over Representative Steep Sloped Roof

This test measures whether the Class A rated roof system still meets the Class A requirements in the presence of a PV module or panel with mounting system. The burning Class A brand is positioned on top of the module or panel. The system passes if there is no sustained flaming of the underside of the plywood deck and no flaming or glowing brands fall off the test deck. This performance criteria is different than the current burning brand test, in which a failure occurs if the brand burns through the module.

If the module or panel is designed only for low slope applications, this test is not required.

Burning Brand Between Module or Panel and Representative Steep Sloped Roof

This test is similar to the previous burning brand test, except that a Class B brand is placed between the module and the roof surface. The rationale for using a Class B brand is explained in the Burning Brand Tests Between Module and Roof section. The pass/fail criteria are the same as the previous burning brand test. If the module or panel is designed only for low slope applications or the module has a guarded perimeter protected with a wire screen or other similar means then this test is not required.

Considerations for UL 2703

The new fire classification test is being implemented first in ANSI/UL 1703-2013, which is a module safety standard. If the module or panel is fire rated, the installation, including the mounting system, will be considered to have a fire classification rating, Class A, B, or C.

UL Outline of Investigation 2703, *Mounting Systems, Mounting Devices, Clamping/Retention Devices, and Ground Lugs for Use With Flat-Plate Photovoltaic Modules and Panels* (UL, 2010) addresses the mounting system. The intention is that the UL 2703 STP will consider and adopt complementary language in that standard to allow evaluation, certification, and labeling of mounting systems.

Industry Solutions

An Industry Solutions project is currently underway to identify and validate solutions that may satisfy the revised ANSI/UL 1703-2013 fire classification requirements through testing specific generic installation geometries that qualify as Class A. Test data analysis, along with details of construction and installation, will be summarized in a forthcoming UL Report. The report will be made public and shared with industry, authorities having jurisdiction, and other stakeholders. For installation assemblies that have been proven to meet Class A requirements, manufacturers could use this information as the basis for certification, and, consequently, installation approval. Ultimately, the data can be used as substantiation for code proposals. Use of industry solutions will also help reduce the number of tests required without excluding any product or system solution from the marketplace.

New Burner

Although the use of commercially available roof coverings in the spread of flame tests was found to be a viable way to evaluate PV fire performance, it has been recognized that variables are introduced because the flame spread performance of roof coverings vary widely. The standard attempts to address this variation by setting acceptable baseline ranges, but there is still variation. Consequently, a new proposal is being researched to replace the roof covering with a burner representative of the thermal stress of the roof fire to the underside of the PV module.

Developing this new burner requires a series of experiments of roofing materials to develop heat release and surface involvement data. These data will be used to design the “burner” test rig and to correlate the two methods. An oxygen consumption calorimeter will be assembled to capture and measure heat release characteristics during tests using the UL 790/1703 test fixture.

Based on these results, the UL researchers will develop a burner test rig and run a series of experiments to evaluate and validate the performance of the new burner. Once this is complete, the UL1703 and UL 2703 STPs will consider a revised fire classification test procedure using the new burner. This research and development is under way and is expected to be completely by the end of 2013.

CONCLUSIONS

UL has conducted research over a period of years to develop a new fire classification test that can more accurately evaluate the effects of a PV module or panel on the fire classification rating of roof coverings. This research has produced the following findings:

- For burning brand tests in which the brand is placed between the PV module and the roof surface, a Class B brand is the closet representation of actual materials likely to collect in this area.
- The critical flux values for ignition of low slope and steep slope roofing products and for crystalline silicon PV modules were found to be generally consistent for products in the same category (validating module 'typing' as a means to streamline testing requirements).
- The first to ignite (roof covering), second to ignite (PV) concept was demonstrated as a viable method for assessing the flammability performance of a system composed of PV, roof covering, and mounting hardware.

Based on these results, a Task Force of the UL 1703 STP developed a draft for a new fire classification test procedure. The new procedure requires the following tests be performed to derive the fire classification rating for the system:

- spread of flame test on the top surface of module or panel,
- spread of flame test at roof and module or panel interface over representative steep or low sloped roof,
- burning brand test on module surface over representative steep sloped roof, and
- burning brand test between the module or panel and representative steep sloped roof.

Following a series of stakeholder meetings and public comment periods, the proposal was revised and in July 2013 the UL STP voted unanimously to approve the new fire classification test procedure. In adopting the new procedure, the STP also recognized that further clarifications and refinements are needed. Some of these potential refinements may include:

- defining additional PV module types in order to address new and old products not currently covered by the existing 3 types, and
- adding flexibility for the standard baseline roof types that meet the 48-inch to 72-inch fire performance criteria. (Recent tests have shown challenges in choosing commercially available roof coverings (within the parameters of the new standard) that also satisfy the baseline requirement.)

In addition to any changes anticipated for ANSI/UL 1703-2013, the UL 2703 STP will consider incorporating the new Fire Classification Test Procedure into that standard. Beyond that, further research is needed in two areas—industry solutions (system tests thatå will help reduce the number of component tests otherwise required to determine system ratings) and completion of a new, calibrated burner flame source that will reduce variability and increase repeatability of tests using commercially available roof coverings.

ACRONYMS

ANSI	American National Standards Institute
EPDM	ethylene propylene diene monomer
FARP	floor and radiant panel
fpm	feet per minute
FR	fire retardant
kW/m^2	kilowatts per square meter
LIFT	lateral ignition and flame travel
PV	photovoltaic
Solar ABCs	Solar America Board for Codes and Standards
STP	Standards Technical Panel
UL	Underwriter Laboratories, Inc.
W/cm^2	watts per square centimeter

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In the Presence of Standoff-mounted Photovoltaic Modules

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In the Presence of Standoff-mounted Photovoltaic Modules

Andrew Rosenthal, Larry Sherwood, Bill Brooks, Pravinray Ghandi, and Bob Backstrom

A Solar ABCs Interim Report
April 2010

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Executive Summary

The object of these tests was to investigate whether and how the presence of standoff-mounted PV arrays may affect the fire class rating of common roof covering materials. In particular, these tests were initiated in response to questions from stakeholders about the language in the UL Guide Card that stated that PV modules may or may not reduce the fire class rating of roof coverings when modules of a lower rating are installed above a roof covering with a higher rating.

In the Summer of 2009, the Solar America Board for Codes and Standards (Solar ABCs) in partnership with Underwriters Laboratories Inc. (UL) designed and conducted tests to characterize the effects of stand-off mounted (elevated, parallel to roof surface) PV modules on the fire rating of Class A rated roofing systems. All tests were conducted by UL in Northbrook, IL, with assistance from representatives of Solar ABCs. Funding for this research was provided by the U.S. Department of Energy.

To assess flammability, "spread of flame" and "burning brand" tests were used. These are UL/ASTM standard tests that are conducted on all roofing systems (during UL 790 certification) as well as on all PV modules (during UL 1703 certification). However, flammability tests are ordinarily performed on either a roof covering or a PV module in isolation. The current tests applied fire and burning material to the roof covering while rack-mounted PV was present. Therefore, unlike UL1703 which evaluates the properties of a PV module in isolation, the current tests were conducted to examine combined effects of modules and roof coverings as a system when exposed to fire. Tests were designed to use the methods of UL 790 to evaluate different combinations of modules, stand-off heights, and roofing materials.

In all cases, when the burning brand was placed on top of either Class A or Class C modules (the standard test geometry from UL 1703) the roof system was found to remain compliant with Class A requirements. However, when the brand was placed on the Class A rated roof covering beneath Class C rated PV modules (a test geometry not defined in either UL 1703 or UL 790) the roof covering remained in compliance with Class A requirements in some cases and in some cases it did not. Multiple tests placing the brand on Class A-rated roof coverings beneath Class A rated PV modules resulted in the roof covering failing to meet the Class A requirements in all cases. Table E1 summarizes the results of the burning brand tests.

Table E1. Results of Burning Brand Tests

Roof Rating	PV Rating	Brand Size / Position	Fire Performance Result
A	C	Class A / PV	Compliant
A	C	Class A / Roof	2 Compliant/ 1 not compliant
C	C	Class C / Roof	Not compliant
A	A	Class A / Roof	Not compliant

During the spread of flame tests it was observed that any panel (even a noncombustible one) mounted at a range of gap heights (standoff) typical of many PV arrays increased the temperature and heat flux present at the roof surface when the flames were applied between the panel and roof. The increased temperature and heat flux are the result of a "channeling effect" through which the panel holds hot gases and flame closer to the roof surface not allowing them to dissipate as they do when not confined. Due to this effect, in all cases, the presence of either Class C or Class A modules mounted above Class A roof materials resulted in the roofing assemblies failing to meet the Class A spread of flame test requirements (i.e. flame spread of greater than 6 feet was observed). Table E2 summarizes the results of the spread of flame tests.

Table E2. Results of Spread of Flame Tests

Roof Rating	PV Rating	Flame Spread
A	C	Greater than 8 ft.
A	A	Greater than 8 ft.
C	C	Greater than 8 ft.
Noncombustible	C	Greater than 8 ft.
Noncombustible	A	Greater than 8 ft.

When comparing spread of flame test results for Class A versus Class C modules, both types were found to fail the tests with the same frequency. It should be noted that spread of flame test failures due to the "channeling effect" would not occur for building integrated PV arrays or arrays that mount directly onto the roof surface with no gap.

Though not part of the initial test plan, a few methods were examined for their potential to prevent the channeling effect observed in the spread of flame tests. Some of these experiments with noncombustible flashings and screening showed great promise, others none at all. Further tests to define and characterize mitigation methods will be conducted in the next phase of the effort.

The effect of varying the setback of the module leading edge from the leading edge of the roof was also studied. The greatest temperature rise was observed when the PV modules were placed in line with the leading edge of the roof. Increasing the setback distance resulted in lower surface temperature measured on the roof.

After completing this round of research, the Solar ABCs and UL convened two meetings with a cross section of volunteer scientists and engineers from the PV industry, the enforcement community, other nationally recognized testing laboratories, and the National Institute of Standards and Technology (NIST). The attendees at these meetings formed a working group that has provided extensive review of the tests that were performed, commented on interpretation of all results, reviewed and revised the content of this Interim Report, and, most importantly, determined and defined the specific tests and objectives for the next round of research. Description of the tests and objectives developed by the PV flammability working group for the next round of research is included in Appendix A.

Based on the current round of testing, reviews and comments by the PV flammability working group and the steering committee of the Solar ABCs, our recommendations are as follows:

1. At present, field experience and thorough review of fire incident data do not indicate an urgent need to revise current practice with regard to code requirements. A major task in the next round of research will be to quantify the potential risk identified by the test results.
2. Further investigation is required to refine the pass/fail criteria for a fire performance test for systems that includes roofing materials as well as the PV array. In addition, tests should be conducted to identify effective means of mitigating fire spread by this roof/PV system. (These tests are presented in Appendix A.)
3. Meetings should be held with fire safety authorities, the solar industry and other interested stakeholders to discuss these test results and determine future test requirements, as needed.
4. Results of these tests and of subsequent stakeholder meetings should be communicated to the UL 1703 Standards Technical Panel for their consideration regarding impact of these results on that test standard.

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Solar America Board for Codes and Standards

The Solar America Board for Codes and Standards (Solar ABCs) is a collaborative effort among experts to formally gather and prioritize input from the broad spectrum of solar photovoltaic stakeholders including policy makers, manufacturers, installers, and consumers resulting in coordinated recommendations to codes and standards making bodies for existing and new solar technologies. The U.S. Department of Energy funds Solar ABCs as part of its commitment to facilitate widespread adoption of safe, reliable, and cost-effective solar technologies.

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Acknowledgements

This material is based upon work supported by the Department of Energy under Award Number DE-FC36-07GO17034.

Table of Contents

Disclaimer ii

Executive Summary iii

Authors v

Table of Contents vi

1.0 General Background on Photovoltaics and Fire Safety 1

1.1 The Role of Underwriters Laboratories in Fire Safety Testing 1

2.0 Reasons for Conducting the Fire Safety Tests 2

2.1 Notes on UL 790 Flammability Testing 2

3.0 Tests Conducted 4

4.0 Test Results 5

4.1 Phase I Test Results – Baseline Test and Tests with Noncombustible Materials 6

4.2 Phase II Test Results – Test Matrix of Different PV Modules and Roof Covering Materials 7

Discussions 8

Recommendations 9

Appendix A: Test Objectives and Test Plan Developed by the PV Flammability Working Group for the Next Round of Research by the Solar ABCs 10

1.0 General Background on Photovoltaics and Fire Safety

As the number of rooftop photovoltaic (PV) systems increases, questions and concerns about fire service response procedures for buildings with PV modules and systems have never been more prevalent. These questions and concerns fall into three categories.

First, in what ways are PV modules and systems designed and installed to prevent ignition of building fires? Modern qualification tests for PV modules are designed to ensure the integrity of PV modules in order to prevent failures that can result in arcing and fires. Similarly, system installation codes for PV (such as the *National Electrical Code*) are constantly updated to address the issue of preventing or controlling PV-initiated fires. Code compliant system designs require elements such as bypass diodes in modules and overcurrent devices in source circuits, as well as adherence to rigorously-developed design rules that specify wire protection, types and sizes, balance of system (BOS) and other component ratings, etc. to reduce the risk of PV-initiated fires.

Second, in what ways can PV systems be installed that protect public and first responder safety in the event of a structural fire and enable fighting a fire if one occurs? In April 2008, the California Department of Forestry and Fire Protection - Office of the State Fire Marshal (CAL FIRE-OSFM), published a guideline for PV installations specifically to address these safety concerns for all structures equipped with rooftop PV systems. It presented certain installation rules for PV systems that mandate necessary signage and specified setbacks and row spacing that ensure that firefighters can use well-developed fire fighting and suppression techniques. The California installation guideline is only the latest action by public safety professionals in this area.

Finally, can the presence of a rooftop PV system contribute to the intensity or spread of a structural fire? It is this third category that was the subject of a series of recent laboratory tests that are being reported in this Solar ABCs Interim Report. These tests were designed specifically to evaluate how PV and roof material interact as a system during exposure to fire and burning material.

1.1 The Role of Underwriters Laboratories in Fire Safety Testing

Underwriters Laboratories Inc. (UL) provides safety and performance testing for thousands of materials and products including both roof covering materials (e.g. shingles) and PV modules. Roofing systems undergo a suite of tests covered in UL 790 – *Tests for Fire Resistance of Roof Covering Materials*, the test standard that determines the fire resistance properties of roofing. All roofing systems undergo these tests as required by local and model U.S. building codes. Roofing systems that demonstrate the highest resistance to burning, burn through, and spreading of flames receive a Class A rating. Materials with less resistance receive a Class B or C rating. Discussion of requirements for these fire class ratings are presented later.

PV modules undergo safety testing to another standard, UL 1703 – *Flat Plate Photovoltaic Modules and Panels*. While this standard describes a suite of tests designed to stress the module physically, environmentally, and electrically, it also subjects modules to a specific subset of UL 790 that results in determination of a fire rating for each PV module.

2.0 Reasons for Conducting the Fire Safety Tests

The testing that is reported in this Interim Report was conducted in response to questions that arose during the development of the Cal Fire OSFM (Office of State Fire Marshall) *Solar Photovoltaic Installation Guidelines.* These questions were restated during discussions held in San Jose, CA on 20 March 2008 between members of the California Solar Energy Industries Association (CALSEIA) and Underwriters Laboratories (UL). CALSEIA requested the meeting to discuss three areas of concern that CALSEIA members had with UL listing requirements or documents. The three areas of concern were listing requirements for various mounting brackets, the need to develop new testing and listing for grounding lugs, and specific language about fire rating for roofs with rack mounted PV arrays contained in the UL Guide information referenced in the 2007 UL White Book.

Regarding the fire rating issue, the language of concern was:

> *Installation of modules on or integral to a building's roof system may adversely affect the roof-covering materials' resistance to external fire exposure if the module has a lesser or no fire-resistance rating. Roof-covering materials will not be adversely affected when the modules have an equal or greater fire-resistance rating than the roof-covering material.*

CALSEIA noted that fire officials had raised concern over the ambiguity in this statement with regard to the most common residential PV roof installation, Class C PV modules mounted over Class A rated roofs. This illuminated the fact that there was a lack of fire test results on systems including PV modules in roof-mounted configurations. Industry representatives requested that UL work to bring clarity to this concern.

In response, UL changed the language of the Guide Card as follows:

> *Installation of modules on or integral to a building's roof system may* ***or may not*** *adversely affect the roof-covering materials' resistance to external fire exposure if the module has a lesser or no fire-resistance rating. Roof-covering materials will not be adversely affected when the modules have an equal or greater fire-resistance rating than the roof-covering material.*

UL also agreed that additional testing was necessary to fully address the concerns expressed by fire officials and CALSEIA. Though roof covering materials and PV modules both receive fire class ratings, little work had been done to investigate the interactions that may occur between them when burning materials or flame are imposed on systems comprised of PV mounted in stand-off configuration over roofing systems. Specifically, it was necessary to investigate whether and how PV modules with Class B or C fire ratings may degrade the fire-resistance properties of Class A rated roofing systems using standard flammability test procedures and methods in a qualified laboratory. With funding from the U.S. Department of Energy, UL and the Solar ABCs developed a test plan to answer these questions.

2.1 Notes on UL 790 Flammability Testing

Throughout this paper, the experimental results of flammability testing as defined in UL 790, "Tests for Fire Resistance of Roof Covering Materials", will be discussed. Fire performance ratings are determined using three different fire tests described in UL 790: spread of flame test, intermittent flame test, and burning brand test. As stated above, PV modules also obtain fire class ratings. During UL 1703 testing, PV modules undergo a subset of the UL 790 tests that includes a burning brand test and spread of flame test. A general understanding of these tests is necessary to use this paper and interpret its results. (Note: for brevity, the intermittent flame test is not described below since it was not used during the testing reported in this Interim Report.)

The spread of flame test applies a natural gas fueled flame of approximately 3 feet in width driven by moving air at a velocity of 12 mph. and measures the potential for

flames to spread across a surface. The intensity of the flame is controlled with greater intensity applied during the Class A test (1400°F) and reduced intensity during the Class C test (1300°F). During the Class A test, flame is applied for 10 minutes. The Class C test applies flame for 4 minutes. Either test is failed if the flame spreads beyond a specific maximum defined for each test (6 feet for Class A, 8 feet for Class B, 13 feet for Class C). The test also fails if fire spreads laterally to both edges of the 40-inch wide sample surface, burning or glowing material falls from the sample and continues to burn or glow or a combustible roof deck is exposed as a result of testing. During PV testing to UL 1703, the test fails if burn through of the PV module is observed.

As will be seen below, some of the spread of flame tests were conducted using noncombustible roof surfaces. It is important to understand that determination of fire class rating using the spread of flame test is based on the observed distance flame travels during the test and that ignition of the roof covering is not required for determination of results.

The burning brand test measures the potential for fire to penetrate from outside a roofing material (or, in the case of UL 1703 tests, a PV module) to the underside of a combustible roof deck. The source of fire is a burning brand, a measured stack of dry wood that is ignited and burns with known properties. The mass of the burning brand for Class A testing is 2000 grams (single brand) and for Class C testing the mass is 9.25 grams (20 brands). In the case of tests for roof coverings, a successful result is obtained if no sustained flame or burning is observed on the underside of the test deck and burning particles have not fallen to the floor and continued to burn. For PV module testing, all of the following conditions must occur for a successful result to be obtained: no part of the module falls to the floor in flames or while glowing, the brand does not burn through the module and through the roof covering below, and there is no sustained flaming of burning of the module itself.

3.0 Tests Conducted

In the Summer of 2009, the Solar America Board for Codes and Standards (Solar ABCs) in partnership with Underwriters Laboratories (UL) designed and conducted specific tests to characterize the effects of stand-off mounted (elevated, parallel to roof surface) PV modules on the fire rating of Class A rated roofing systems. All tests were conducted by staff members of UL's Corporate Research Division in Northbrook, IL, with assistance from representatives of Solar ABCs. The tests included the "burning brand" test and the "spread of flame" test normally conducted on PV modules during UL 1703 certification of all PV modules but with a major difference. During UL 1703 certification testing, fire and burning materials are applied to the top surface of the PV module only. The tests conducted for this study were designed specifically to impose fire between the module and roof covering. Therefore, unlike UL1703 which evaluates the properties of a PV module alone in isolation, the current tests were conducted to examine combined effects of modules and roof coverings as a system when exposed to fire and flame. Tests were designed to use the methods of UL 790 to evaluate different combinations of modules, stand-off heights, and roofing materials.

The test plan was initially designed to be conducted in two phases and, based on the results obtained, a subsequent third phase of testing was added. The objectives of the three test phases are described as follows:

Phase I (non-combustible panels mounted over non-combustible roof decks, limited tests using actual PV modules mounted over roof assemblies):

1. Establish baseline data of fire exposure on roof deck samples without PV according to UL 790
2. Determine the effects of stand-off height and leading edge setback on results of UL 790 testing with non-combustible materials.

Phase II (Class A and C fire rated PV modules mounted over standard roofing systems)

1. Determine the effects of varying PV installation parameters on Class A and C rated PV modules on UL 790 test results
2. Determine the impact of lesser fire rated PV modules on common roofing systems
3. Investigation of potential mitigation techniques.

Phase III (Class A and C fire rated PV modules mounted over standard roofing systems)

1. Validation of Phase II results
2. Further investigation of mitigation techniques.

4.0 Test Results

4.1 Phase I Test Results – Baseline Test and Tests with Noncombustible Materials

The first task of Phase I was selection of the different roofing products and PV modules that would be used during all subsequent tests. Five different roofing systems were selected for use: *asphalt impregnated fiberglass matt three tab shingle, asphalt impregnated fiberglass laminated mat or 'architectural' shingle, cedar shake shingle, 2" thick rigid Isocyanurate foam covered with a single ply of Ethylene propylene diene monomer (EPDM) membrane, asphalt-coated glass-fiber mat (felt) – Type G1 (ply sheets), and a Type G3 (granular surfaced).* The PV modules selected for testing were not identified or sorted by model or manufacturer. The only characteristic of the PV modules recorded during testing was each module's original fire class rating, either Class A or Class C.

All tests in Phase I were performed on a roof with a standard slope of 5:12 (23°) and with a noncombustible PV module mounted parallel to the roof surface. PV modules were mounted on adjustable, metal rods so that the stand-off height (called Gap in this report, the distance between the back of the module and the roof surface) could be selected. During the first round of testing, gap heights of 2.5, 5 and 10 inches were used. Roof mounts also enabled the adjustable placement of the module so that the distance between the leading edge of the roof and the leading edge of the module, the setback, was also selectable. During the first round of testing, setback lengths of 0, 12, and 24 inches were used. The test assembly was fitted with thermocouples, heat flux gauges, and bi-directional velocity probes to record experimental conditions during testing. Automated data acquisition equipment sampled data from all sensors at a 1 second rate during testing.

Phase I testing began with a series of spread of flame tests performed using noncombustible roof materials and noncombustible panels (in place of actual roofing systems and PV modules). This series of tests was designed to assess the influence of any noncombustible stand-off structure mounted above a roof surface on temperature rise and heat flux.

The first test used no panel above the roof covering (stated another way, the gap was infinite). This was conducted to provide a baseline of temperature rise and heat flux on the roof surface during flame exposure in the Class A spread of flame test of UL 790. Eleven tests then followed using the noncombustible panel mounted above the roof surface at various gap heights and setback distances from the roof's leading edge. These tests were conducted for five minutes.

The results of the first set of tests were consistent. When mounted to simulate PV modules, even noncombustible panels used during the spread of flame test, held hot gases closer and for longer distances near the roof surface. This "channeling effect" of hot gases significantly raised the temperature and heat flux at the roof surface making it more difficult for the roofing system to pass the spread of flame test. The magnitude of this effect was found to be a function of both gap height and setback distance. Increases in temperature and heat flux were greatest at 5 inch gap height and less at a gap height of 2 inches. At a gap height of 10 inches, there was less of a difference in temperature and heat flux at the roof surface compared with baseline. With regard to setback distance, the temperature rise was greatest with zero setback and least as setback distance was increased to 24 in.

The results of the first round testing indicated that worst case conditions occurred when gap height was 5 inches and setback was 0 inches. These conditions were used for the next round of testing. In this round, two spread of flame and two burning brand tests were conducted using actual PV modules and roof covering materials. All tests utilized Class C PV modules mounted over Class A shingle roofing.

For the two spread of flame tests, one test utilized vertical mounting rails (rails running up the slope of the roof) while the second test utilized horizontal mounting rails (rails running parallel to the roof's edge). Both spread of flame tests resulted in flames extending beyond the roof decking in excess of 8 feet before the ten minute requirement for Class A rating had been reached. That is, in both spread of flame test cases, the results of mounting Class C modules above Class A roof materials resulted in the roofing assemblies failing to meet requirements under the Class A spread of flame test.

For the two burning brand tests conducted during this round, the first evaluated the results of placing the burning brand on top of the module surface and allowing it to burn. The second evaluated the results of placing the burning brand on the roof surface beneath the PV module (within the 5 inch gap between module and roof). In the case of the burning brand test with Class A PV module mounted on a Class A roof system, the roof system was compromised (i.e. no longer met Class A requirements). In the case of the burning brand test with a Class C PV module mounted above a Class A roof material, the roof system was not compromised.

4.2 Phase II Test Results – Test Matrix of Different PV Modules and Roof Covering Materials

Phase II testing broadened the number of different combinations of PV modules and roofing systems subjected to UL 790 conditions. It had the dual goals of validating the early results from Phase I and of evaluating the possibly greater or lesser severity of flammability attainable by different combinations of PV and roof coverings. The Phase II tests used spread of flame and burning brand methods on a matrix of PV and roof covering combinations.

The spread of flame tests were performed with Class A and C fire rated PV modules mounted over Class A roof coverings (3 tab composition shingles, membrane, architectural shingles, and hot mopped), over Class C roof coverings (wood shake), and over noncombustible roof coverings. During all tests, the gap height was 5 inches and the setback distance was 0 inches. The result for every spread of flame test was flame propagation beyond the length of the roof deck (> 8 feet) and failure to conform to the requirements for Class A systems (< 6 feet).

One finding of the Phase II spread of flame tests has prompted much discussion among reviewers of this paper and bears comment. This regards the results for spread of flame tests involving noncombustible roof coverings. As mentioned above, the results of spread of flame tests conducted on noncombustible roof coverings with rack-mounted PV present was flame spread beyond 8 feet. Determination of fire class rating using the spread of flame test is based on the observed distance flame travels during the test. Thus, based on the standard criteria of the test, the tested systems comprised of noncombustible roof covering with rack-mounted PV failed to conform to Class A requirements. In no case did ignition of the roof covering occur, but this is not required for determination of results.

The burning brand tests were conducted with Class C fire rated PV modules mounted over Class A roof covering (3 tab composition shingle) and Class C roof covering (wood shake). The brand size was based on the roof fire rating – tests involving roofing products rated Class A utilized a Class A brand, tests involving roofing products rated Class C utilized a Class C brand. The Class C designation of the wood shakes was based on identification of such by the supplier and validation testing was not performed.

Results of tests placing the burning brand either on top of or beneath the Class C PV module over a Class A roof passed the requirements for Class A systems. The results of placing the burning brand directly on the Class C roof beneath a Class C module failed to conform to Class C requirements. And a test with the burning brand placed on the surface of a Class A roof material beneath the Class A module failed to conform to the requirements of the Class A system.

The influence of the set back of the leading edge of the modules from the leading edge of the roof was studied. The influence of the PV modules was highest when the PV modules were placed in line with the leading edge of the roof. The greater the distance of the leading edge of the PV from the leading edge of the roof, the lower will be the surface temperature of the roof.

4.3 Phase II and III Test Results - Mitigation Techniques

During Phase II and III testing, a few techniques for mitigating the impact of rack-mounted PV on the fire resistance properties of the roofing system were evaluated. These experiments were not designed to be completed before publication of this paper and were conducted to gain insight into future directions of this work. The mitigation techniques fell into three categories: the use of various configurations of flashings and screens to block fire from passing between module and roof, the use of increased setback of rack-mounted PV from the source of flames, and application of non-combustible panels to the back of the rack-mounted PV modules.

The mitigation methods showing the most promise will receive further tests to fully characterize their ability to mitigate effects of standoff-mounted PV on flammability properties of roof coverings.

5.0 Discussion

The object of these tests was to investigate whether and how the presence of standoff-mounted PV arrays may affect the fire class rating of common roof covering materials. In particular, these tests were initiated in response to questions from stakeholders about the language in the UL Guide Card that stated that PV modules may or may not reduce the fire class rating of roof coverings when modules of a lower rating are installed above a roof covering with a higher rating.

In preparing this study, the authors had many discussions with PV and fire safety professionals. In no case was anyone aware of a wind driven rooftop fire intensified by the presence of PV modules. The authors also conducted a review of fire incident data (National Fire Incident Reporting Systems) and found no record of any building fire in which wind driven flames or brands have travelled along a rooftop equipped with a rack-mounted PV array. In the case of recorded fire incident data, however, it should be noted that records often do not include details of this kind.

The results of testing demonstrated that any panel (even a noncombustible one) mounted at a range of gap heights (standoff) typical of many PV arrays will increase the temperature and heat flux present at the roof surface during the spread of flame test. The increased temperature and heat flux are the result of a "channeling effect" through which the panel holds hot gases and flame close to the roof surface not allowing them to dissipate as they do when not confined.

As a result of this "channeling effect," PV modules of any fire rating (Class A or C) mounted in a 5 inch standoff configuration will hold sufficient heat against the roof surface such that previously Class A rated roof coverings will no longer meet the Class A requirements during the UL 790 spread of flame test. Testing also determined that Class A rated PV modules mounted at a 5 inch gap height prevented Class A rated roof coverings from meeting the Class A requirements of the burning brand test when the brand was placed on the roof below the modules. When this test was performed using Class C modules, the test results were inconsistent.

Finally, initial testing found mitigation techniques that show promise of preventing the degradation of roof covering fire class rating by rack-mounted PV modules. These techniques will be tested further.

After completing this round of research, the Solar ABCs and UL convened two meetings with a cross section of volunteer scientists and engineers from the PV industry, the enforcement community, other nationally recognized testing laboratories, and the National Institute of Standards and Technology (NIST). The attendees at these meetings formed a working group that has provided extensive review of the tests that were performed, commented on interpretation of all results, reviewed and revised the content of this Interim Report, and, most importantly, determined and defined the specific tests and objectives for the next round of research. Description of the tests and objectives developed by the PV flammability working group for the next round of research is included in Appendix A.

6.0 Recommendations

PV flammability group recommendations for the next round of research are included in Appendix A. Based on the current round of testing, reviews and comments by the PV flammability working group and the steering committee of the Solar ABCs, our recommendations are as follows:

1. At present, field experience and a thorough review of fire incident data do not indicate an urgent need to revise current practice with regard to code requirements. A major task in the next round of research will be to quantify the potential risk identified by the test results.
2. Further investigation is required to refine the pass/fail criteria for a fire performance tests for systems that includes roofing materials as well as the PV array. In addition, tests should be conducted to identify effective means of mitigating fire spread by this roof/PV system. (These tests are presented in Appendix A.)
3. Meetings should be held with fire safety authorities, the solar industry and other interested stakeholders to discuss these test results and determine future test requirements, as needed.
4. Results of these tests and of subsequent stakeholder meetings should be communicated to the UL 1703 Standards Technical Panel for their consideration regarding impact of these results on that test standard.

Appendix A

Test Objectives and Test Plan Developed by the PV Flammability Working Group For the Next Round of Research by the Solar ABCs

RESEARCH OBJECTIVES

There are two main objectives for the next round of research.

The first objective of the next round of research will be to provide specific tests and procedures that can be applied to PV installations and components to verify that they will have no impact on the fire rating of the roof assemblies (with an emphasis on Class A rated roof assemblies).

The second will be to develop these tests and procedures into the form needed to serve as input for modifications to existing codes and standards such as UL1703, ICC, Model Codes, etc.

TEST PLAN

1. Conduct Class A Spread of Flame tests on Class C PV module mounted over Class A roofs to see if the roof assembly will routinely pass Class A Spread of Flame test. Conduct tests for three different geometries, different module types, and over non-combustible roof products.

2. Verify the Burning Brands Tests previously conducted in order to define when mitigation is required. Conduct tests for different brand locations, different module types, and different roof types including non-combustible roof products. Investigate potential caloric load of debris accumulated under solar array to determine which size burning brand is appropriate for placement between the PV modules and the roof assembly.

3. Conduct Class A Spread of Flame tests for modules at tilts that are not parallel to the roof surface in order to determine how their performance compares with tests conducted on modules parallel to the roof surface.

4. Perform research to quantify the potential risk identified by the test results. A fire protection research engineer, economist, or actuarial insurance consultant will be hired to conduct this research.

5. Test several Spread of Flame mitigation techniques in order to develop mitigation recommendations. Document all test methods for preparation of recommendations so that these may be added to existing standard.

6. Develop and test Burning Brand mitigation techniques in order to provide mitigation recommendations. Tests to be developed after Item 2 tests define when mitigation is required. Develop language for required maintenance and cleaning between module and roof assembly.

7. Conduct Spread of Flame test on a large array to learn if tests conducted on single modules scale accurately to arrays with many modules.

Solar America Board for Codes and Standards

www.solarabcs.org

Characterization of Photovoltaic Materials – Critical Flux for Ignition / Propagation Phase 3

Project Number: 11 CA43479
File Number: SV19060
Date: January 16, 2012

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EXECUTIVE SUMMARY

This report is a third phase continuation of a research project conducted to determine the effect of rack mounted photovoltaic (PV) systems on the flammability classification rating of roofing materials. The original project (Phase 1) was conducted in response to fire and building code officials' interest in determining if a Class C rated module would reduce the fire resistance performance and/or fire rating of some Class A rated roof systems. And if so, which roof systems are impacted and to what extent. Results of that activity were documented in a report titled "Effect of Rack Mounted Photovoltaic Modules on the Fire Classification Rating of Roofing Assemblies" dated September 30, 2009, revised November 30, 2010. The research was expanded in a second phase to arrays mounted at various angles to a roof and a comparison of standard ignition brands to wood excelsior and leaf debris. These results were published in a report titled "Effect of Rack Mounted Photovoltaic Modules on the Fire Classification Rating of Roofing Assemblies Phase 2" dated January 30, 2012.

Phase 1 - An analysis of the data generated by the experiments carried out in the first study [1] pointed to the following key findings:

- The presence of a rack mounted PV module on a roof has an adverse effect on the fire performance of the roof regardless of the fire rating of the roof or the Class rating of the PV panel based on Spread of Flame test method described in UL 790 *Standard for Safety for Standard Test Methods for Fire Tests of Roof Coverings*, Eighth Edition, Dated April 22, 2004 and UL 1703 *Standard for Safety for Flat Plate Photovoltaic Modules and Panels*, Third Edition, Dated March 15, 2002.
- The extent of the degradation on fire performance with respect to flame spread of a roof depends upon PV installation parameters such as setback distance and separation gap between roof and PV module.
- The presence of a rack mounted PV module on a roof could adversely affect the fire performance of the roof when subjected to burning brands placed on the roof based on the Burning Brand test method described in UL 790.

Phase 2 - An analysis of the data generated by the experiments carried out in the second study [2] pointed to the following key findings:

- Some PV modules mounted at angles (positive and negative) to steep and low sloped roofs impacted the fire classification rating of the supporting roof assembly. The extent of the impact was dependent on the angle of the module relative to the roof and the type of roofing system.
- PV modules mounted at zero clearance to the roof surface demonstrated no impact to the fire rating of the roof when the ignition source flame was directed to the front vertical surface of the module or when the ignition source flame was directed along the horizontal face of the module.
- The heat release rate and heat transfer to the roof surface of Class A and Class C brands did not demonstrate a direct correlation to common materials that may collect between PV modules and the roof surface, such as leaf debris and excelsior (wood wool). The Class A brand yielded results significantly greater than the leaf debris and

[1] Effect of Rack Mounted Photovoltaic Modules on the Flammability of Roofing Assemblies, Date: September 30, 2009, Revised March 5, 2010

[2] Effect of Rack Mounted Photovoltaic Modules on the Flammability of Roofing Assemblies, Date: September 30, 2009, Revised March 5, 2010

wood excelsior while the Class C brand yielded results significantly less than the leaf debris and wood excelsior. While the Class B brand was not included in the experiments, the deduction of these experiments is that the representation of common materials is closest to the Class B brand in terms of heat release and heat transfer to the roof surface. .

As an extension of the above work, a broad stakeholder group to the Solar ABC's projects held meetings to discuss the project results and what actions should be taken. The group consensus was that work should be initiated toward revisions to the fire tests in UL 1703, *Standard for Safety for Flat-Plate Photovoltaic Modules and Panels*. To satisfy this objective, the matter was brought to the UL 1703 Standards Technical Panel (STP). A task group was convened under the STP to develop a proposal to modify the current flame spread test and burning brand test to more appropriately evaluate the flame spread and burning brand resistance of roof mounted PV modules as an assembly, i.e. the PV modules in conjunction with the intended roof structure. The proposed approach addresses the research findings that evaluating the fire performance of PV modules and roofs independently does not indicate performance of the combination.

However, during discussions, attendees at stakeholder meetings as well as members of the STP expressed concerns regarding the number of tests that would be required to evaluate multiple combinations of PV and roofing systems. It was acknowledged that although roofing systems may be generally grouped into low and steep sloped roofs, the number of manufacturers and types of roofing products within this two groups were thought to be in excess of what could be reasonably evaluated by a PV manufacturer. The Phase 3 study reported herein was commissioned to determine possible similarities of roofing materials in a an effort to optimize the coverage of a PV / roofing system evaluation to a large number of roofing types while minimizing the amount of testing required.

Summary of Findings

An analysis of the data generated by the experiments in this Phase 3 point to the following key findings:

- The critical flux values for most of the roofing products was determined to be greater than the 15 kW/m^2 exposure measured on the surface of a noncombustible deck without a PV (see Table 1, Assembly 1). Exceptions being one architectural shingle, one membrane and two insulation boards with critical heat flux values of 14, 14, 13, 14 kW/m^2 respectfully.
- The critical flux values for all of the roofing products was determined to be less than the 41 kW/m^2 exposure measured on the surface of a noncombustible deck with a PV installed with a gap of 5" (see Table 1, Assembly 34).
- The critical flux for ignition of low slope roof products was found to be generally consistent as were the critical flux for ignition of high slope roof products.

Continuation of Fire Safety Research Project

This project was conducted to expand on previously collected empirical data for consideration by manufacturers of PV and roofing products, regulatory officials such as Authorities Having Jurisdiction, and code and standards development organizations. It is anticipated that the results of these experiments will lead to potential code and standards revisions.

Acknowledgments

The authors would like to acknowledge the following individuals for their contributions including guidance and support for this project:

Bill Brooks of Brooks Engineering
Larry Sherwood of Sherwood Associates
Kevin Lynn of the Department of Energy (DOE)
Andy Rosenthal of New Mexico State University

1. TABLE OF CONTENTS

EXECUTIVE SUMMARY 3
Summary of Findings 4
Continuation of Fire Safety Research Project 4
Acknowledgments 5
Introduction 7
Critical Flux 7
Determination of Critical Flux for Ignition / Propagation 8
Objectives and Technical Plan 8
Background - Heat Flux Measurements from Phase 1 Project: 11
Samples 12
Experimental Plan 12
ASTM E648 Results 13
ASTM E1321 Results 13
ASTM E1354 Results 14
SUMMARY AND RECOMMENDATIONS 22
SUMMARY OF FINDINGS 22
RECOMMENDATIONS 22

Introduction

This research project described herein expands on work conducted in Phases 1 and 2. Phase 1 of this project sought to address regulatory concerns over the installation of Class C fire rated PV modules over Class A fire rated roofs. Results of that activity have been documented in a report titled "Effect of Rack Mounted Photovoltaic Modules on the Fire Classification Rating of Roofing Assemblies" dated September 30, 2009, revised November 30, 2010. Phase 2 sought to address questions regarding 1) fire spread of along modules mounted at 0 in. clearance installation height above the roof, 2) arrays installed at various angles to the roof, and 3) comparison of Class A and Class C burning brands and common materials that may collect between PV modules and the roof surface, represented by leaf debris and excelsior (wood wool). The results were published in a report titled "Effect of Rack Mounted Photovoltaic Modules on the Fire Classification Rating of Roofing Assemblies Phase 2" dated January 30, 2012.

As an outgrowth of the above work, a broad stakeholder group to the Solar ABCs projects held meetings to discuss the project results and what actions should be taken. The group consensus was that work should be initiated towards revisions to the fire tests in UL 1703, "Flat-Plate Photovoltaic Modules and Panels". To satisfy this objective, the matter was brought to the UL 1703 Standards Technical Panel (STP). A task group was convened under the STP to develop a draft proposal to modify the current test flame spread and burning brand test to more appropriately evaluate the flame spread and burning brand resistance of roof mounted PV modules as an assembly - the PV modules in conjunction with the intended roof structure. This proposed approach more closely aligns with the research findings.

However, during discussions, attendees at stakeholder meetings as well as members of the STP expressed concerns regarding the number of tests that would be required to evaluate multiple combinations of PV and roofing systems. It was acknowledged that although roofing systems may be generally grouped into low and steep sloped roofs, the number of manufacturers and types of roofing products within this two groups were thought to be in excess of what could be evaluated by a PV manufacturer. This study, Phase 3, was commissioned to determine possible similarities of roofing materials in an effort to optimize the coverage of a PV / roofing system evaluation to a large number of roofing types and while minimizing the amount of testing required.

Critical Flux

Critical flux is a fundamental fire property of a material and can be defined as the minimum level of incident radiant flux energy required for ignition, expressed as energy per unit area (kW/m^2 or W/cm^2). In some model building code applications such as floor covering materials [3], the critical flux required to propagate a flame along a surface is used to regulate the permissible materials.

[3] International Fire Code, 2012 Edition - Interior floor finish and floor covering materials required by Section 804.3.3.2 to be of Class I or II materials shall be classified in accordance with NFPA 253. The classification referred to herein corresponds to the classifications determined by NFPA 253 as follows: Class I, 0.45 watts/cm^2 or greater; Class II, 0.22 watts/cm^2 or greater.

For a sense of scale and comparative purposes, values for critical flux of some common materials are given below:

- Wood, newspaper – 9 to 12 kW/m^2 [4]
- Asphalt – 22 to 27 kW/m^2 [5]
- Polyisocyanurate foam – 17 kW/m^2 [6]

Determination of Critical Flux for Ignition / Propagation

Objectives and Technical Plan

The objective of this phase was to assess a material flammability parameter (critical flux) of materials used in the construction of PV modules and representative roofing products. This data would be used to:

1. document relative fire performance to better understand the contribution of materials to the flame spread of PV module and roofing assemblies,
2. provide quantitative data to support generic Type classifications of PV module construction,
3. develop a data baseline for future use in reviewing proposed materials in third party listed products.

The technical plan consisted of conducting experiments on a variety of common roofing and PV products to determine the critical flux for ignition or propagation.

Experiments were conducted following the test protocols outlined in:

- ASTM E 648, "Standard Test Method for Critical Radiant Flux of Floor-Covering Systems Using a Radiant Heat Energy Source, also known as the Floor and Radiant Panel Apparatus (FARP)",
- ASTM E1321, "Standard Test Method for Determining Material Ignition and Flame Spread Properties, also known as the Lateral Ignition and Flame Travel apparatus (LIFT)" and,
- ASTM E1354, "Standard Test Method for Heat and Visible Smoke Release Rates for Materials and Products Using an Oxygen Consumption Calorimeter", also known as the cone calorimeter apparatus.

---

[4] Spearpoint M J, Quintiere J G. Predicting the ignition of wood in the Cone Calorimeter - effect of species, grain orientation and heat flux. Fire Safety Journal, Vol 36/4, pp. 391-415, 2001.

[5] Colwell – Test Methodologies for reaction to fire of pavement materials, Sustainable & Advanced Materials for Road Infracsture, SAM-04-B20, 2005

[6] Quintiere and Harkleroad – New Concepts for Measuring Flame Spread Properties, National Bureau of Standards, NBSIR 84-2943, 1984

Photographs of each of the test fixtures are shown in Figures 1, 2 and 3.

Figure 1 – Figure Illustrates ASTM E648 FARP Test Apparatus

Figure 2 – Figure Illustrates ASTM E1321 LIFT Test Apparatus

Figure 3 – Figure Illustrating ASTM E1354 Cone Calorimeter Test Apparatus

Background - Heat Flux Measurements from Phase 1 Project:

Phase 1 of the Project included measurements of the heat flux exposure of the UL 790 / UL 1703 flame spread test. Experiments were conducted on noncombustible deck with and without a noncombustible surrogate of a PV module. These heat flux measurements provide an opportunity for comparison of critical flux of roofing and PV materials to the spread of flame exposure.

The temperature and heat flux data from those fire tests are reprinted here and summarized in Table 1 for twelve experiments. For a complete review of this data, please reference the original project report ("Effect of Rack Mounted Photovoltaic Modules on the Flammability of Roofing Assemblies", Date: September 30, 2009, Revised March 5, 2010).

Table 1 - Results for Spread of Flame test on simulated PV module and roof

Assembly ID	Gap (in)	Setback (in)	Rail	Temperature @ 5 mins			Average Temp Rise (last 30 sec)			Heat Flux Max	
				1	3	4	1	3	4	1	2
				(°F)	(°F)	(°F)	(°F)	(°F)	(°F)	(kW/m^2)	(kW/m^2)
1	N/A	N/A	N/A	502	177	151	371	93	65	15	3
7	2 1/2	0	N/A	948	465	362	859	355	260	23	9
9	2 12	12	N/A	747	384	292	679	313	211	16	8
11	2 1/2	24	N/A	457	294	232	261	175	135	7	6
12	5	0	Vertical	974	768	562	-	-	-	29	22
17	5	0	Horiz.	1008	751	604	909	688	513	34	17
22	10	0	N/A	630	373	327	-	-	-	19	9
24	10	12	N/A	551	374	332	458	292	246	17	7
26	10	24	N/A	490	317	280	381	223	183	11	7
34	5	0	N/A	1066	719	576	939	637	508	41	25
35	5	24	N/A	600	430	369	499	334	279	12	9
36	5	12	N/A	865	518	406	703	428	316	23	12

Samples

PV modules and roofing products samples used in these Phase 3 experiments were either donated by industry or purchased from local retailers. The PV modules were a metal framed glass on polymer design, representative of Class C fire classification rating. The roofing products consisted of Class A steep slope 3 tab and architectural roof shingles, base and cap sheets, EPDM and FR EPDM membranes, and polyisocyanurate insulation boards:

- Composite or 'stacks' cut from PV modules consisting of glass, encapsulant and cell and backplane layers (3 manufactures)
- 3 tab shingles (3 manufactures)
- Architectural shingles (3 manufacturers)
- Base sheet (1 manufacturer)
- Cap sheet (2 manufacturers)
- EPDM membrane (1 manufacturer)
- FR EPDM membrane (1 manufacturer)
- Insulation board (1 manufacturer)
- FR insulation board.(1 manufacturer)

Specimens for each experiment were prepared in accordance with the respective test protocol.

Experimental Plan

The experimental plan to obtain critical flux for ignition was to obtain the values using the FARP apparatus, followed by the LIFT apparatus and finally the Cone apparatus. The plan was to then to compare measured values from the different test methods for the same roofing or PV product to gain an understanding on the influence of the test method and fixture on critical flux values.

Critical flux measurements are obtained directly from the FARP and LIFT experiments using the ASTM E648 and E1321 test protocols. In both of these test protocols the flame front or propagation along the sample surface is directly related to the incident radiant flux exposure during the test. A calibration is conducted to establish the heat flux / distance relationship. The critical flux is then determined from the point at which the flame front progresses.

The cone calorimeter protocol using the ASTM E1354 procedure does not determine critical flux directly as a reported result from the test protocol. Rather, the test apparatus may be used to conduct experiments at multiple heat flux exposures in order to derive the critical flux by plotting heat flux vs. ignition times. The technique is described in National Institute of Standards and Technology publication titled "Predicting the Ignition Time and Burning Rate of Thermoplastics in the Cone Calorimeter".[7] Three experiments were conducted on each material at three heat flux exposures - To determine the critical flux for ignition, the reciprocal of the time to ignition (1/

[7] Hopkins, Predicting the Igntion Time and Burning Rate of Thermoplastics in the Cone Calorimeter", NIST-GCR-95-677, September 1995

t_{ign}) was plotted vs heat flux for each sample. A linear best fit equation was fitted to the data. The x axis intercept (heat flux) indicated the critical flux.

For the membrane and insulation board samples, experiments were conducted at 25, 50, and 70 kW/m^2. For the granulated roofing products and PV module 'stack' samples, experiments were conducted at 35, 50 and 70 kW/m^2.

All roofing materials samples were specimens cut from the individual product (shingle, sheet or membrane). The PV module stack specimens were cut from full modules. The PV modules were Class C, metal framed, and glass on polymer construction.

ASTM E648 Results

Experiments were conducted on two shingles using the FARP (ASTM E648) apparatus. Additional experiments on other materials were not conducted as the flame front did not propagate beyond the ignition source impingement zone. These results indicate the critical flux of the roofing product was greater than that generated in the apparatus which is 10 kW/m^2.

Figure 4 – Figure Illustrating Sample After Exposure in the ASTM E1321 Test Apparatus

ASTM E1321 Results

Experiments using the LIFT (ASTM E1321) were also inconclusive. During the conduct of the initial experiments with samples in a horizontal configuration, the test fixture became overheated resulting in damage to the equipment. Additional experiments were not attempted.

ASTM E1354 Results

Critical flux values determined from cone calorimeter measurements are tabulated in Table 2; individual test results for the various materials are plotted in Figures 5 through 21. The following is a summary of the experiment results:

- The critical flux for the three PV module stacks ranged from 31 to 34 kW/m^2
- The critical flux for the three tab shingles ranged from 18 to 22 kW/m^2
- The critical flux for the architectural shingles ranged from 14 to 26 kW/m^2
- The critical flux for the base and cap sheets ranged from 15 to 18 kW/m^2
- The critical flux for the two non-fire retardant membranes were 14 and 18 kW/m^2, whereas the fire retardant product was 19 kW/m^2
- The critical flux for the non-fire retardant and fire retardant insulation boards was 13 and 14 kW/m^2 respectfully

Table 2 Summary of Cone Calorimeter measured Critical Flux Results

Product	Critical Flux (kW/m^2)
PV Module Stack #1	32
PV Module Stack #2	34
PV Module Stack #3	31
Shingle - 3 tab #1	18
Shingle - 3 tab #2	22
Shingle - 3 tab #3	21
Shingle – architectural #1	21
Shingle – architectural #2	26
Shingle – architectural #3	14
Base Sheet #1	17
Cap Sheet #1	18
Cap Sheet #2	15
Membrane – EPDM #1	14
Membrane - FR EPDM #1	19
Membrane –TPO #1	18
Insulation Board #1	13
FR Insulation Board #1	14

Plots of 1/ t_{ign} vs time – 3 Tab Shingles:

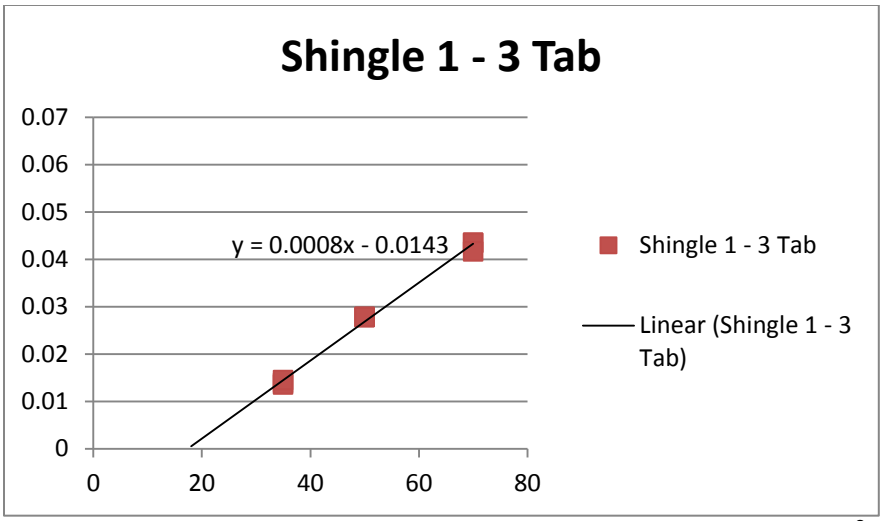

Figure 5 - Graph of 1 / Time to Ignition Vs Heat Flux in kilowatts/m^2

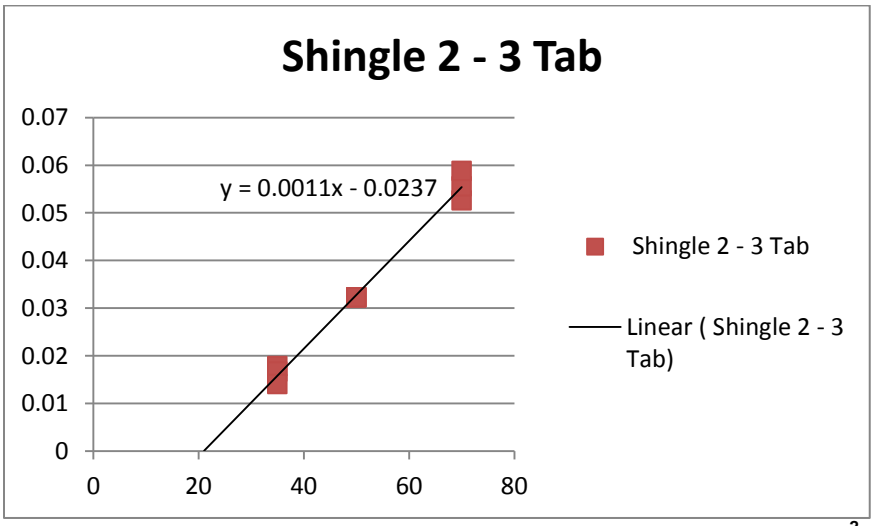

Figure 6 - Graph of 1 / Time to Ignition Vs Heat Flux in kilowatts/m^2

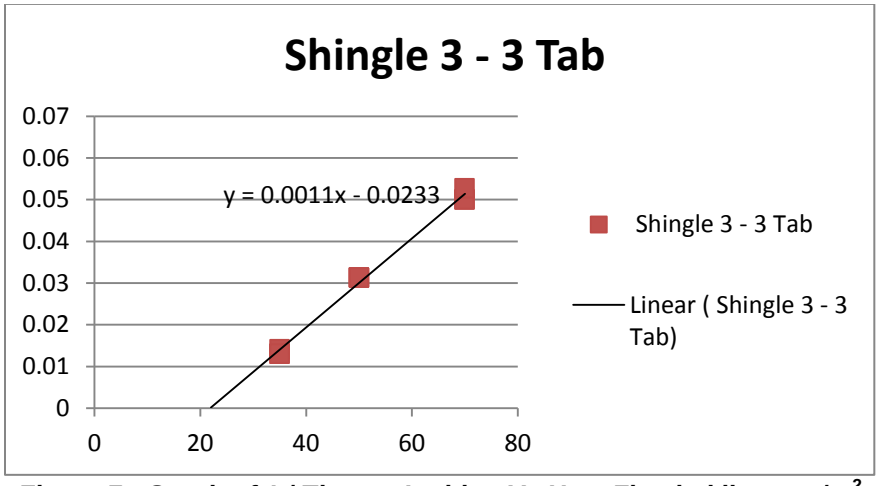

Figure 7 - Graph of 1 / Time to Ignition Vs Heat Flux in kilowatts/m^2

Plots of 1/ t_{ign} vs time – Architectural Shingles:

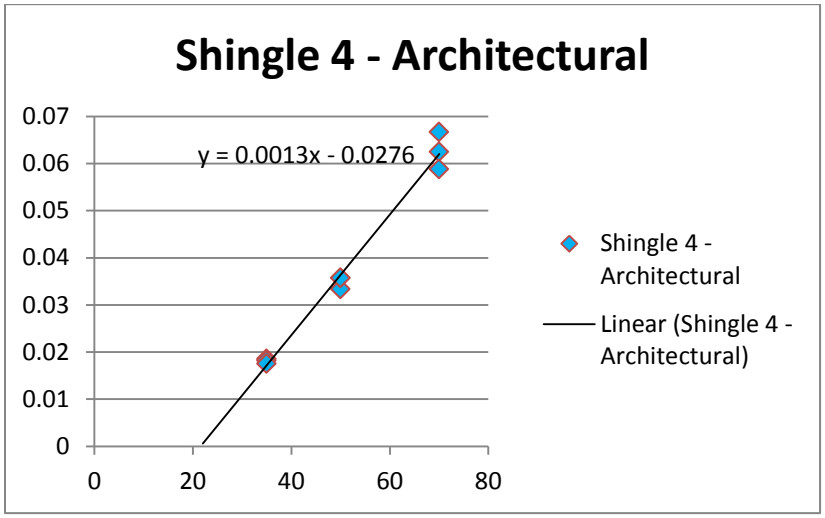

Figure 8 - Graph of 1 / Time to Ignition Vs Heat Flux in kilowatts/m^2

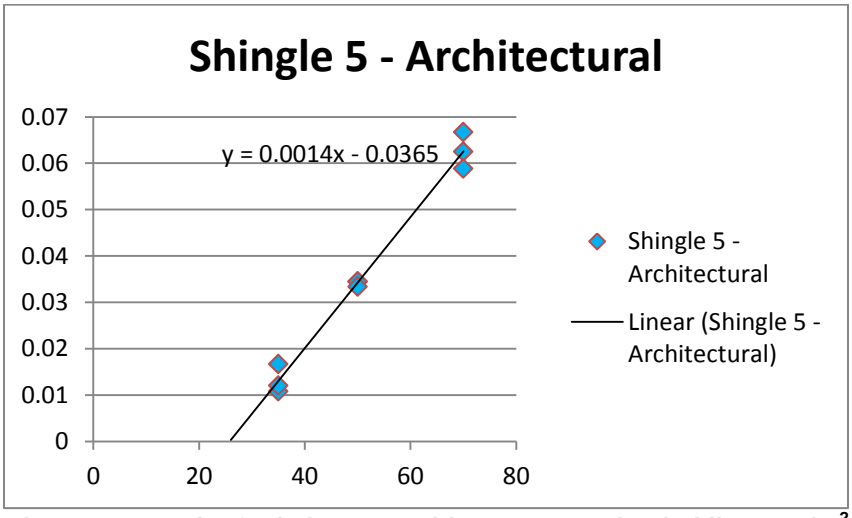

Figure 9 - Graph of 1 / Time to Ignition Vs Heat Flux in kilowatts/m^2

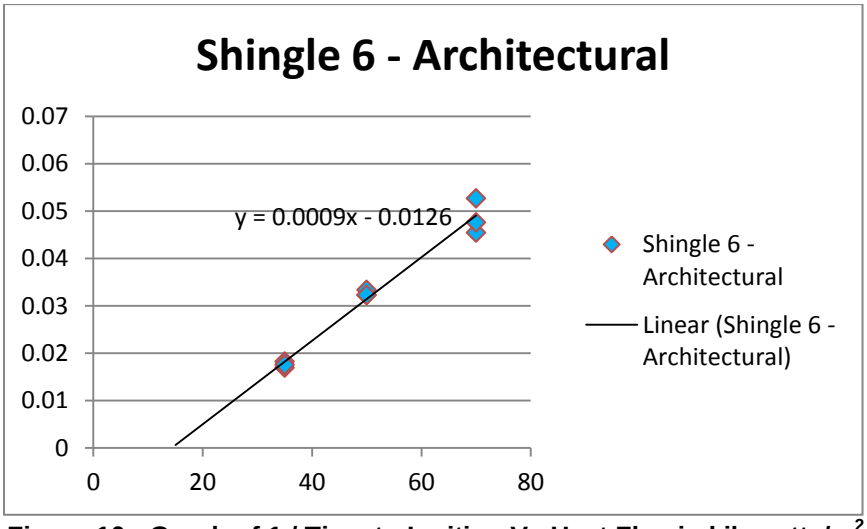

Figure 10 - Graph of 1 / Time to Ignition Vs Heat Flux in kilowatts/m^2

Plots of 1/ t_{ign} vs time – Base & Cap Sheets:

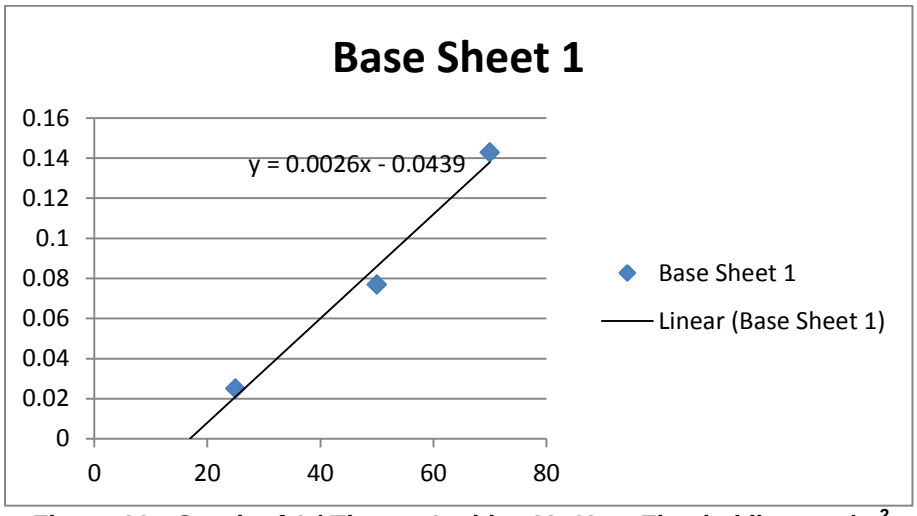

Figure 11 - Graph of 1 / Time to Ignition Vs Heat Flux in kilowatts/m^2

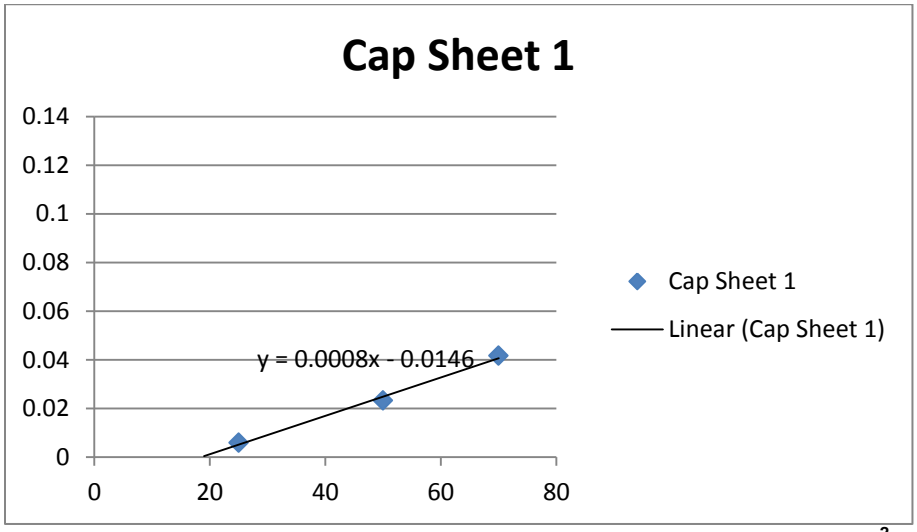

Figure 12 - Graph of 1 / Time to Ignition Vs Heat Flux in kilowatts/m^2

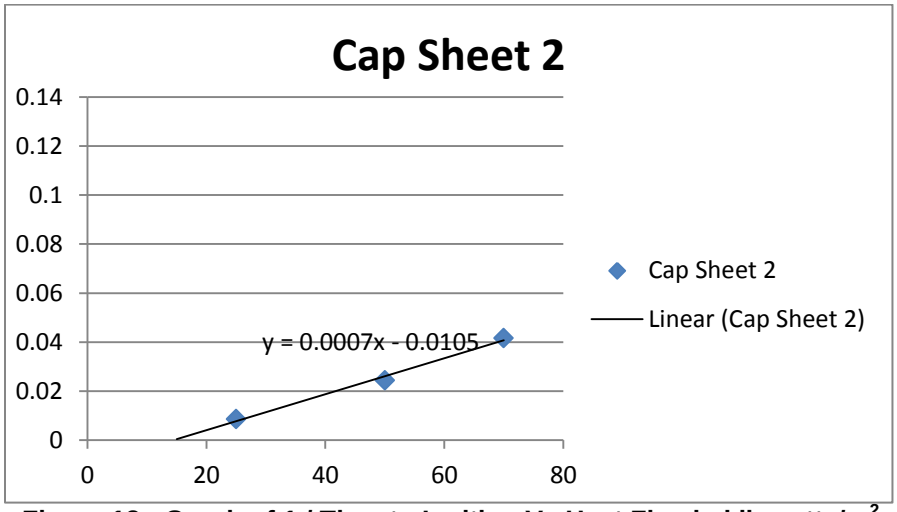

Figure 13 - Graph of 1 / Time to Ignition Vs Heat Flux in kilowatts/m^2

Plots of 1/ t_{ign} vs time – Low Slope Membranes:

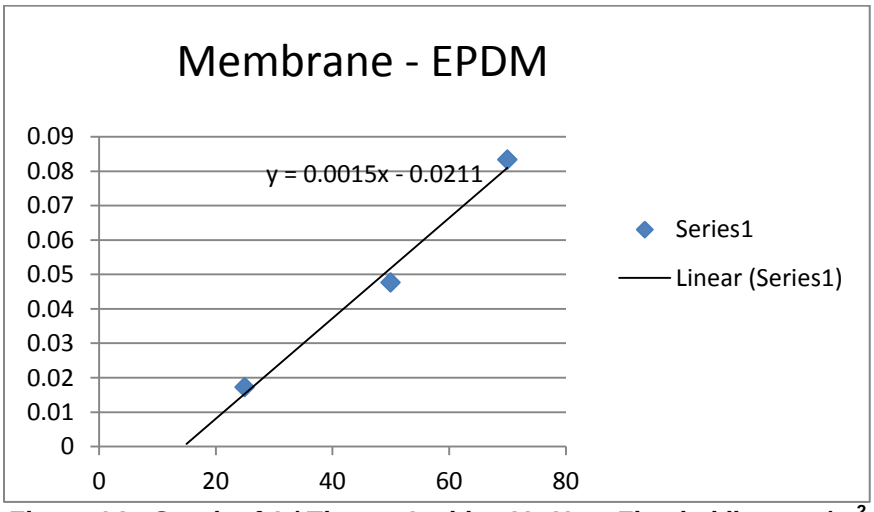

Figure 14 - Graph of 1 / Time to Ignition Vs Heat Flux in kilowatts/m^2

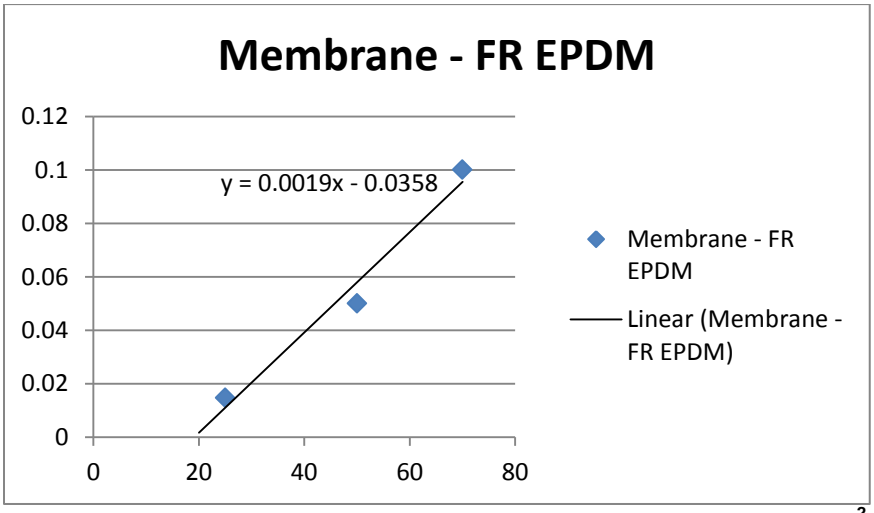

Figure 15 - Graph of 1 / Time to Ignition Vs Heat Flux in kilowatts/m^2

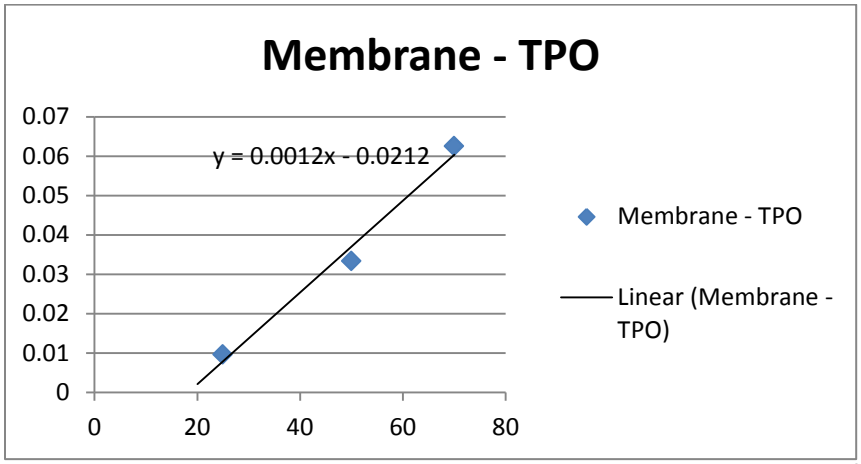

Figure 16 - Graph of 1 / Time to Ignition Vs Heat Flux in kilowatts/m^2

Plots of 1/ t_{ign} vs time – Low Slope Insulation Board:

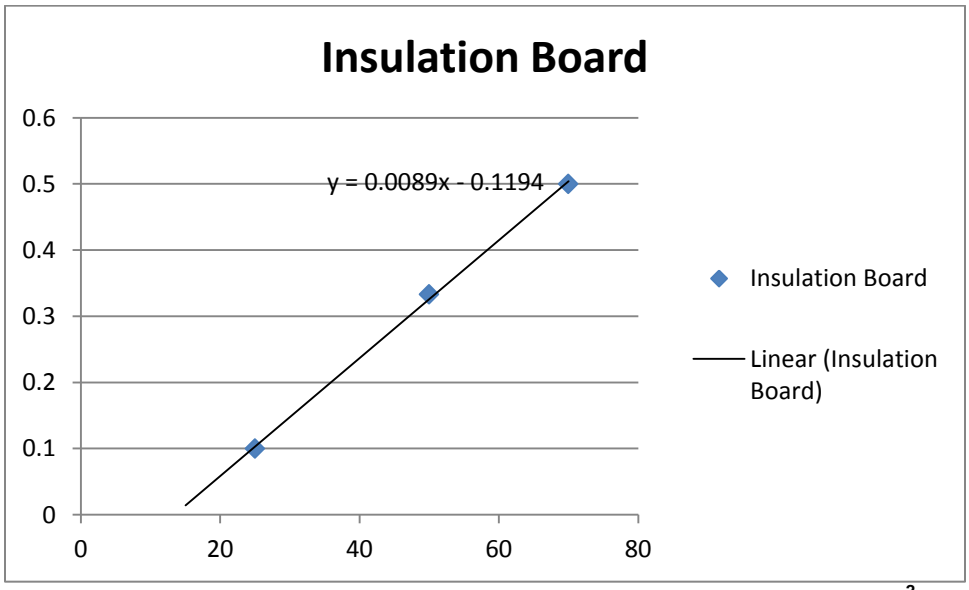

Figure 17 - Graph of 1 / Time to Ignition Vs Heat Flux in kilowatts/m^2

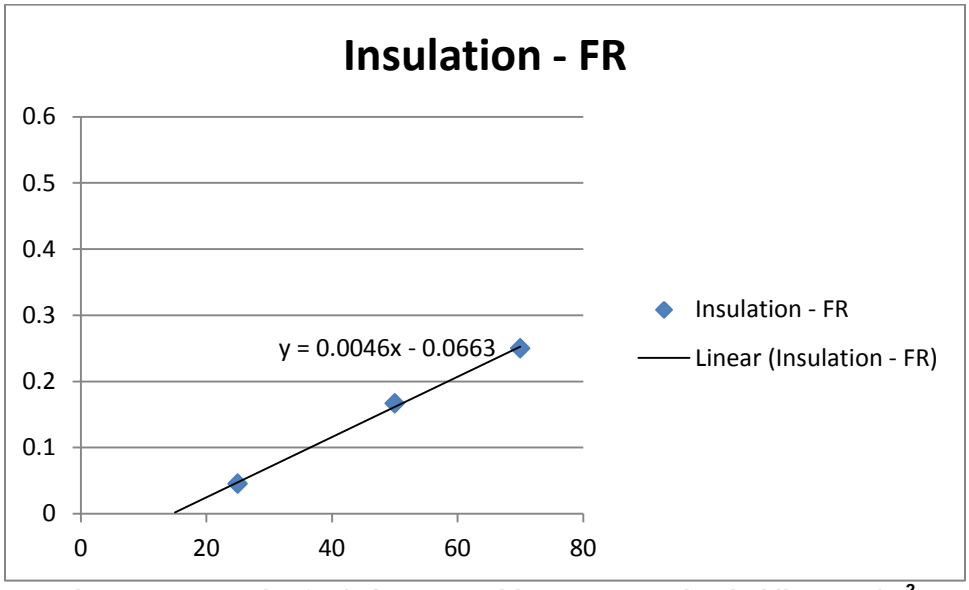

Figure 18 - Graph of 1 / Time to Ignition Vs Heat Flux in kilowatts/m^2

Plots of 1/ t_{ign} vs time – PV Module Stacks:

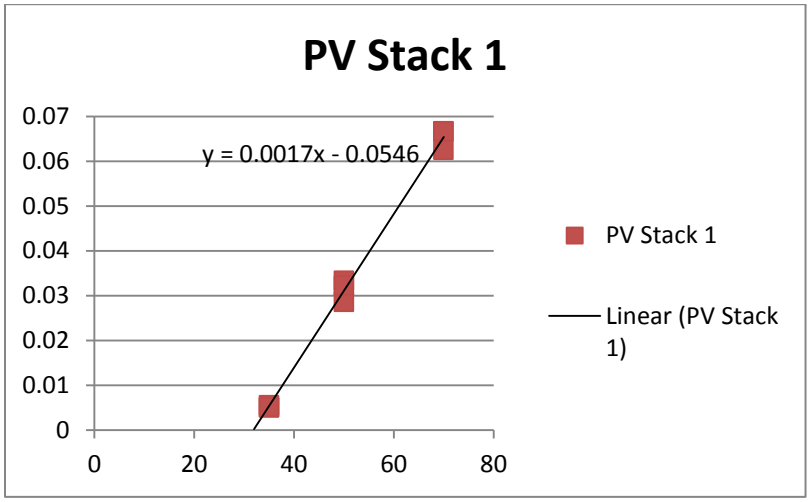

Figure 19 - Graph of 1 / Time to Ignition Vs Heat Flux in kilowatts/m^2

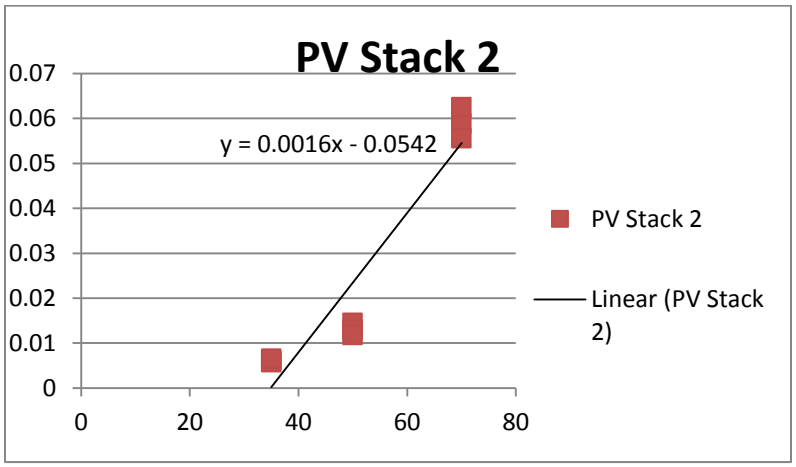

Figure 20 - Graph of 1 / Time to Ignition Vs Heat Flux in kilowatts/m^2

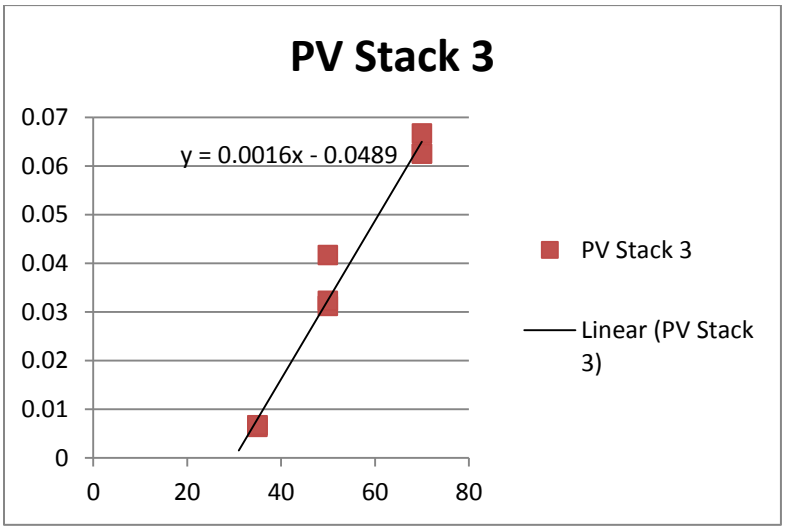

Figure 21 - Graph of 1 / Time to Ignition Vs Heat Flux in kilowatts/m^2

SUMMARY AND RECOMMENDATIONS

SUMMARY OF FINDINGS

An analysis of the data generated by the experiments carried out in this study point to the following key findings:

- The critical flux values for most of the roofing products was determined to be greater than the 15 kW/m^2 exposure measured on the surface of a noncombustible deck without a PV (see Table 1, Assembly 1). Exceptions being one architectural shingle, one membrane and two insulation boards with critical heat flux values of 14, 14, 13, 14 kW/m^2 respectfully.
- The critical flux values for all of the roofing products was determined to be less than the 41 kW/m^2 exposure measured on the surface of a noncombustible deck with a PV installed with a gap of 5" (see Table 1, Assembly 34).
- The critical flux for ignition of low slope roof products was found to be generally consistent as were the critical flux for ignition of high slope roof products.

It should be noted that the roofing products had been evaluated by UL 1703 and have attained a Class A rating either a product in the case of a shingle or as a component of a system in the case of the low slope materials (sheets, insulation, membrane). As such a degree of fire performance would be expected.

RECOMMENDATIONS

Based on the research study findings, the Research Team would like to make the following recommendations and suggestions:

- Conduct additional experiments on other low slope membranes such as TPO and PVC materials to gain a better understanding of the critical flux for ignition of other technologies.
- Conduct additional ASTM E1354 cone calorimeter tests to determine other properties which have an effect on fire performance such as time to ignition, peak heat rate and effective heat of combustion. These characteristics can be determined on individual materials/products and combinations of products such as membrane-insulation systems.
- Continue research in this area to evaluate the sensitivity of the fire performance of roofing systems to the various PV installation methodologies. As a matter of practicality, it is unlikely that a manufacturer would submit every possible PV and roofing product installation configuration for fire test evaluation. Further work is needed to determine a generic roofing material which can be utilized as a worst case representative for testing of PV modules.
- This research should be shared with the PV and roofing industries as well as external fire community (firefighters, fire marshals, and authorities having jurisdiction - AHJs).
- Conceptually, the critical flux for ignition can be used to quantify a material or combination of materials propensity to ignite and spread flame. This parameter should be used by the UL 1703 Standards Technical Process (STP) fire test working group for defining generic categories of PV modules and roofing materials.

- Propose to the UL 1703 STP a requirement that for PV modules comprised of a glass superstrate; polymeric encapsulant; polymeric substrate with metal framing the laminate matrix or stack shall have a critical radiant flux no lower than 25 kW/m^2.
- Propose to the UL 1703 STP a requirement that for PV installations over steep slope roofs, a Class A three tab shingle shall be used in the evaluation of PV modules and have a critical flux of no higher than 25 kW/m^2.
- Propose to the UL 1703 STP a requirement that for PV installations over low slope roofs, a Class A single-ply EPDM rubber membrane shall be used in the evaluation of the PV module and have a critical radiant flux no higher than 20 kW/m^2.

Report of Experiments of Minimum Gap and Flashing for Rack Mounted Photovoltaic Modules
Phase 4

Project Number: – 11CA43479
File Number: IN15911
Date: March 29, 2012

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Acknowledgments

The authors would like to acknowledge the following individuals for their contributions including guidance and support for this project:

Bill Brooks of Brooks Engineering
Larry Sherwood of Sherwood Associates
Kevin Lynn of the Department of Energy (DOE)
Andy Rosenthal of New Mexico State University

1. TABLE OF CONTENTS

Acknowledgments 3
Introduction 5
Objectives 5
Samples 5
  Steep Slope Roof 5
  Low Roof Slope 6
Experiments 6
  PV-to-Rooftop Gap 6
  Flashing 7
Results 7
  PV-to-Rooftop Gap Experiments 7
  Flashing Experiments 8
SUMMARY OF FINDINGS 9

Introduction

The research described herein expands on previous work conducted over multiple phases of a broader project[1] to determine the effect of rack mounted photovoltaic (PV) modules on the fire rating of roof assemblies. In general, these earlier experiments demonstrated that the flame spread ratings of the roof are not maintained when PV modules are installed elevated above the roof. An initial study measured the surface temperature and incident heat flux of a noncombustible roof with a noncombustible PV module mock-up installed at 10, 5 and 2.5 inches above the roof. All three PV-to-rooftop gap configurations resulted in increased surface temperature and heat flux on the roof assembly as compared to these measurements without the PV module. The highest heat flux and surface temperature values were with the 5 in. gap.

In this phase (Phase 4) of the investigation, data for some methods to mitigate the flame propagation through the gap between the PV module and the rooftop were developed.

Objectives

The objectives of this phase of the investigation were to:

1. Determine the minimum PV-to-rooftop gap which may maintain the roof covering's original fire rating; and
2. Develop data on the effect of sheet metal flashing to block the passage of flames between the PV module and the roof assembly.

Samples

Commercially available PV modules and roof covering samples were acquired either through industry donation or purchased from local retailers.

For the PV-to-rooftop gap experiments PV modules were a Class C fire rated metal framed glass on polymer design. In addition, a PV surrogate module consisting of a noncombustible sheet was also used.

For the flashing experiments, PV modules were Class C fire rated metal frame glass on polymer design.

The test assemblies representing high roof slopes (5:12 ratio), and low slopes (xx:xx ratio) were constructed using Class A roof covering materials for the UL 790/ASTM E108 Spread of Flame tests as follows:

Steep Slope Roof

One type of steep slope assembly consisting of Class A 3-tab shingles secured to a ¾ in. oriented strand board (OSB) was used.

---

[1] Effect of Rack Mounted Photovoltaic Modules on the Flammability of Roofing Assemblies, Dated September 30, 2009, Revised March 5, 2010

Low Roof Slope

Three types of low slope roof assemblies were used as described herein:
a. Rolled asphalt on 2 inch thick polyisocyanurate insulation mechanically fastened to a noncombustible deck;
b. Fire retardant single ply EPDM (60 mil) over 2 inch thick polyisocyanurate insulation board mechanically fastened to a noncombustible deck; and
c. TPO (60 mil) over 2 inch thick polyisocyanurate insulation board mechanically fastened to a noncombustible deck.

Experiments

Fire performance of the PV modules/surrogate on roof deck assemblies was investigated by Spread of Flame tests as described in UL 790 "Standard Test Methods for Fire Tests of Roof Coverings" and UL 1703 "Standard for Safety, Flat-Plate Photovoltaic Modules and Panels". In UL 790/ASTM E108 standard, Class A roof covering materials have flame propagation not exceeding 6 ft.

In the experiments, the PV module or the surrogate was mounted parallel to the roof surface.

PV-to-Rooftop Gap

In these experiments, the PV-to-rooftop gap was varied from 12 in. to 24 in.to determine the minimum gap at which the Class A rating of the roof covering materials was retained. Two experiments were conducted on high slope assemblies and four experiments were conducted on low slope assemblies.

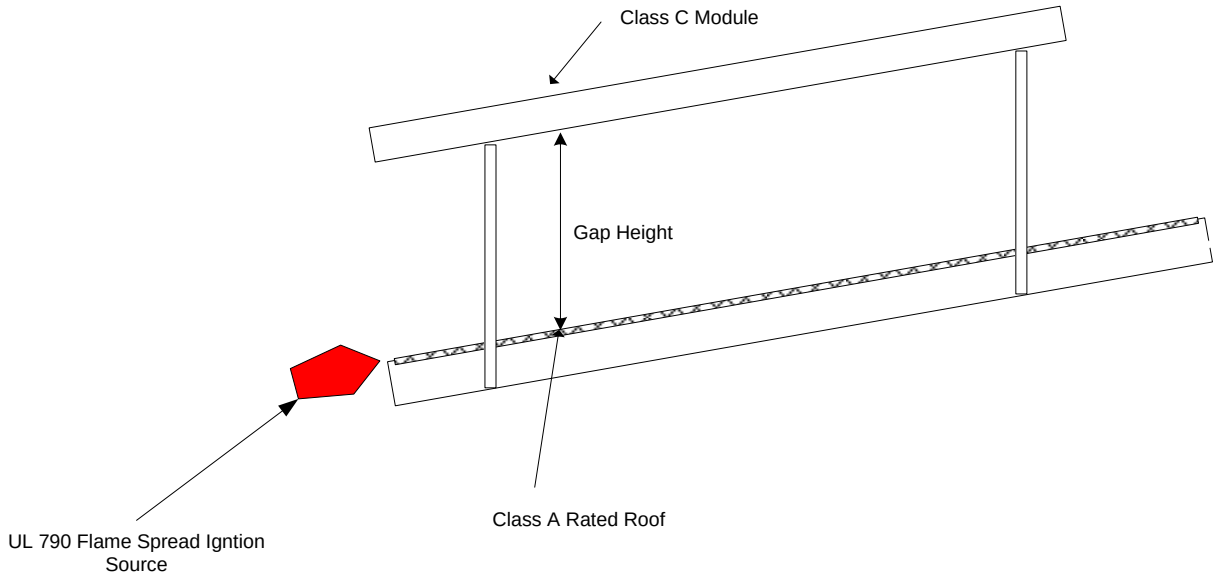

Figure 1 – Figure Illustrating Roof / PV Module Experiment Assembly With a Gap

Flashing

In these experiments, a Class C PV module was installed parallel to the roof surface, with a gap of 5 inches. A 26 AWG galvanized sheet metal flashing was placed from the top of the PV module to rooftop to either completely block the gap or to allow a ½ inch gap.

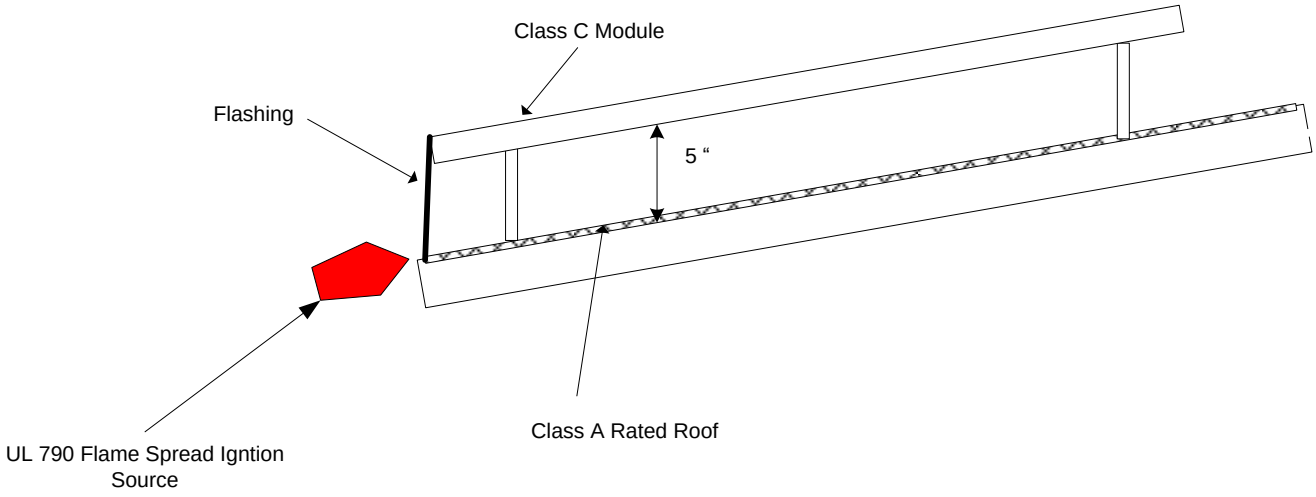

Figure 2 – Figure Illustrating Roof / PV Module Experiment Assembly With a Continuous Flashing

Results

PV-to-Rooftop Gap Experiments

Maximum flame spread distances and the corresponding time at which they occurred for the various roof assemblies experiments are listed in Table 1.

Table 1 - Summary of PV-to-Rooftop Gap Experiments

Roof Slope	Roof Covering	PV / Surrogate	Gap (in.)	Maximum Flame Distance (ft.)	Time for Maximum Flame Spread (Min:Sec)
Steep	3 tab shingles	Surrogate	12	5.25	9:36
Steep	3 tab shingles	Class C PV Module	12	4.5	8:26
Low	Rolled Asphalt	Surrogate	12	>6	2:33
Low	FR EPDM	Surrogate	16	>6	1:47
Low	FR EPDM	Surrogate	20	>6	1:53
Low	TPO	Surrogate	24	>6	5:16

With the steep slope, both the Class C and the surrogate PV modules had maximum flame spread less than 6 ft. at a gap of 12 inches. Thus, higher PV-to-rooftop gaps were not further investigated.

However, for the low slope roof tests, all the roof assemblies with the PV surrogate had flame spread distances exceeding 6 ft., even at gap distance of 24 inches. Thus, for these assemblies tests with Class C PV module was not conducted.

Post experiment photographs of a compliant steep slope and noncompliant low slope roof configuration are shown in Figures 1 and 2.

Figure 3 – Figure Illustrating Steep Slope Roof / PV Module Assembly 12“ Gap Sample After Flame Spread Experiment

Figure 4 – Figure Illustrating Low Slope FR EPDM Roof / PV Surrogate Assembly 24” Gap After Flame Spread Experiment

Flashing Experiments

Maximum flame spread distances and the corresponding times at which they occurred for the roof assemblies are listed in Table 2.

Table 2 - Summary of Flashing Experiments

Roof Slope	Roof Covering	Flashing Opening (in.)	Roof Flame Spread		Module Flame Spread		Lateral Spread	
			Maximum Distance (ft.)	Time to Maximum Flame Distance (Min:Sec)	Maximum Distance (ft.)	Time to Maximum Flame Distance (Min:Sec)	Spread to Width of the Assembly	Time to Maximum Flame Distance (Min:Sec)
Steep	Shingle	0.5	0	*	0	*	No	*
Low	FR EPDM	0	0	*	0	*	No	*
Low	FR EPDM	0.5	0	6:13	3 1/2	6:32	Yes	7:14
Low	TPO	0.5	5 1/2	6:39	5 1/2	6:39	Yes	6:52
Low	Mod Bit*	0.5	3	8:02	5 1/2	8:02	Yes	9:11

Notes: * - No flame spread

The steep slope, 3 tab shingled roof assembly with ½ inch gap in the flashing between the PV module and roof assembly exhibited flame spread performance that met the criteria of a Class A roof.

The low slope PV module-roof assembly with a continuous flashing without an opening between the roof surface and the PV module (0 in. flashing opening) completely blocked the interstitial was successful in preventing the flames entering the opening between PV module and the roof top. Experiments on low slope roof assemblies with ½ inch opening provided by the flashing did not have flame spread longitudinally exceeding 6 ft. However, they had lateral flame spread that extended to the width of the test assembly.

Selected photographs of a flashing with the opening blocked, and a ½ in. opening are shown in Figures 3 and 4 respectively.

Figure 5 – Photograph of Flame with a the Opening Blocked by Flashing Installed on a Low Slope Roof Assembly

Figure 6 – Photograph of Flame with a ½ in. Flashing Opening Flashing Installed on Low Slope Roof Assembly

It may be observed from Figure 3 that when the flashing completely blocks the opening between the rooftop and the PV module, the flame is deflected above the panel; and when there is a ½ in. flashing opening (Figure 4), the flame extension between the rooftop and the PV module is limited longitudinally but tends to spread laterally.

SUMMARY OF FINDINGS

Although the experiments conducted for this report are not exhaustive, an analysis of the generated data point to the following key findings:

- A noncombustible representation of a PV module (i.e., PV surrogate) and a Class C PV module mounted 12 inches above a Class A shingled roof, when evaluated in a steep slope configuration, both exhibited no flame spread greater than 6 feet, no significant lateral flame spread, nor burning embers. These results are in conformance to Class A roof rating.

- A gap of 12 inches and up to 24 inches between a noncombustible representation of a PV module and various low slopes Class A membrane over insulation roofs generated flame spread distances greater than 6 feet. These results are not in conformance to a Class A roof rating.

- A metal flashing that completely blocked the opening between the rooftop and the PV module prevented flames from entering the interstitial space between an elevated PV module and the roof assembly surface. This result is in conformance with a Class A roof rating.

- A metal flashing with 1/2” opening between the rooftop and the PV module allowed flames to enter the interstitial space between an elevated PV module and various low slope roofs. The flames then propagated laterally to the edge of the roof. This result is not in conformance with Class A roof rating.

- A metal flashing with 1/2” opening between the rooftop and the PV module allowed flames to enter the interstitial space between an elevated PV module and a steep slope shingled roof. However, the flame spread did not exceed 6 feet; no significant lateral flame spread was observed; and no burning embers were emitted from the PV module or the roof assembly. These results are in conformance with a Class A roof rating.

Considerations of Module Position on Roof Deck During Spread of Flame Tests
Phase 5

Project Number: – 11CA43479
File Number: IN15911
Date: July 24, 2012

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Acknowledgments

The authors would like to acknowledge the following individuals / organizations for their contributions including guidance and support for this project:

Bill Brooks of Brooks Engineering
Larry Sherwood of Sherwood Associates
Joe Cain of Solar City
Holly Thomas of the Department of Energy (DOE)
Andy Rosenthal of New Mexico State University

DRAFT

1. TABLE OF CONTENTS

Acknowledgments 3
Introduction 5
Samples 6
Experiments 6
Low Slope Results 6
Steep Slope Results 11
Summary and Recommendations 16
Summary of Findings 16
    Low slope: 16
    Steep slope: 16
Recommendations 17

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Introduction

The research described herein expands on previous work conducted over multiple phases of a broader project[1,2,3,4] to determine the effect of rack mounted photovoltaic (PV) modules on the fire rating of roof assemblies. In general, the experiments demonstrated that the flame spread ratings of the roof are not maintained when PV modules are installed elevated above the roof. An initial study measured the surface temperature and incident heat flux of a noncombustible room with a noncombustible PV module surrogate installed at 10, 5 and 2.5 inches above the roof. An analysis of the data indicated the 5 inch gap height to be the most critical of the three that were evaluated in terms of increased radiant flux and roof surface temperature. All three gap configurations increased the surface temperature and heat flux on the roof assembly higher than those measured in the absence of the PV module.

A subsequent second project further investigated rack mounted PV modules on roof decks to determine (1) the effect of PV modules mounted at angles (positive and negative) to steep and low sloped roofs, (2) the impact of PV modules mounted at zero clearance to the roof surface and with the ignition source directed in the plane of the roof or the plane of the PV surface, and (3) the heat release rate and transfer to roof surface of Class A, B, C brands and common materials such as leaf debris and excelsior (wood wool).

A third project investigated the critical flux for ignition of roofing and PV products. While the individual values varied, most were within the range of the flux values measured on the roof in the original experiments without the PV module in place.

Then a fourth project was undertaken to validate the performance of two approaches thought to mitigate the effect of rack mounted PV modules on the fire ratings of roofs - a minimum separation gap and a sheet metal flashing to block the passage of flames between the PV module and the roof assembly. A continuous flashing was determined to effectively block the passage of flame along the roof under a PV module. A minimum distance of 12 inches above a steep slope (shingled) roof was determined to sufficiently separate the two surfaces to maintain the roof's original fire rating. Experiments up to a height of 24 inches above a low slope roof resulted in flame spread in excess of the performance criteria for a Class A roof.

This report of Project 5 describes a series of experiments to investigate a modification of the current UL 1703 spread of flame test to (1) expose a PV module to flames originating from the UL790 (ASTM E108) ignition source, (2) allow those flames to generate on a representative roof section, and (3) observe the propagation of the flames underneath the candidate PV module being tested. Previous research within Project 1 had been conducted with the PV module installed in a position where both the roof and the module were subjected to the ignition source with zero set back and with only modest set back distances (24 inches or less). The

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[1] Effect of Rack Mounted Photovoltaic Modules on the Flammability of Roofing Assemblies, Dated September 30, 2009, Revised March 5, 2010,

[2] Effect of Rack Mounted Photovoltaic Modules on the Fire Classification Rating of Roofing Assemblies, Dated January 30, 2012

[3] Characterization of Photovoltaic Materials – Critical Flux for Ignition / Propagation Phase 3 Dated January 16, 2012,

[4] Determination of Effectiveness of Minimum Gap and Flashing for Rack Mounted Photovoltaic Modules. Phase 4 Dated March 29, 2012

repositioning of the PV module was conducted to investigate an application of first item (roof) / second item (module) ignition sequence. This concept was investigated to refine the understanding of the effect of a rack mounted PV array on the fire rating of a Class A roof. Experiments were conducted on low and steep slope roofs.

The results of this investigation could be used to:

1. draft a proposal of a revised test method for consideration by the UL 1703 Standards Technical Panel (STP) for inclusion into the standard,
2. provide quantitative data to support code revisions, and
3. develop a test methodology to establish details of PV installations which can be described generically for use by industry and potentially adopted in code regulations.

Samples

Commercially available PV modules and roofing product samples were acquired either through industry donation or purchased from local retailers. The PV modules were a Class C fire rated metal framed glass on polymer design. A surrogate representation of a PV module was simulated using a noncombustible sheet for some experiments.

UL 790/ASTM E 108 Class A rated roof deck assemblies consisted of:

- 3 tab shingles over ¾" plywood – Note: three manufacturers of shingles were used in the experiments.
- 60 mil LSFR EPDM (low slope, fire retardant, ethylene propylene diene monomer) over 4 inch thick polyisocyanurate insulation board mechanically fastened to a noncombustible deck

Experiments

Fire performance of the PV modules/surrogate on roof deck assemblies was investigated by Spread of Flame tests as described in UL 790 ‘‘Standard Test Methods for Fire Tests of Roof Coverings’’ and UL 1703 ‘‘Standard for Safety, Flat-Plate Photovoltaic Modules and Panels’’.

For these experiments, the objective was to conduct the experiments with the module subjected to a thermal exposure resulting primarily from the burning roof. This was accomplished by positioning the module at a distance beyond exposure of the test fixture ignition source, but within range of the flame progression along the surface of the roof. Baseline experiments were conducted to establish the flame propagation along the roof's surface in the absence of a PV module.

Low Slope Results

Six experiments were conducted with low slope roofs. Maximum flame spread distances and the corresponding time at which they occurred for the various low slope roof assembly experiments are listed in Table 1. The baseline experiment without a PV module present demonstrated a maximum flame spread distance along the roof of approximately 5 ft., which is Class A compliant.

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A noncombustible PV surrogate was installed at a gap height of 5 in and an offset of 48 in. The flame spread along the roof extended under the PV module and the total spread of flame along the roof was 8 ft. (Class A, noncompliant.) The same configuration, but with an offset of 52 in., exhibited a flame spread of 8.5 ft.(Class A, noncompliant).

A series of experiments were conducted with aluminum framed glass on polymer PV modules installed at a gap height of 5 in. With the module installed at an offset of 48 in and parallel to the roof (0° inclination), the flame spread extended to 8 ft. (Class A, noncompliant). A third roof / PV experiment was conducted with the module offset at 48 in., but with the module installed at a slight angle to the roof (10° inclination) resulting in a flame spread of 4 ft.(Class A compliant). A final experiment was conducted with two modules angled to the roof (10° inclination), the first offset 24 in. and the second spaced 12 in. from the first. Flame spread across the roof surface with both modules fully involved with flames extending beyond the deck.

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Table 1 - Summary of Repositioning Experiments – Low Slope

					Roof					PV						
		Gap		Module	Time of Flame Spread			Max			Time Flame Spread					
	System	Height	Angle	Offset	3.0'	3.5'	4.0'	Distance	Time	Ign	1'	2'	3'	4'	Full Panel	
System #	Notes	(in)	(deg)	(in)	(m:s)	(m:s)	(m:s)	(ft)	(m:s)	(m:s)	(m:s)	(m:s)	(m:s)	(m:s)	(m:s)	Pass/Fail
Tests conducted June 6, 2012																
12	Baseline	N/A	N/A	N/A	3:07	NR	4:33	5	10:00	N/A	N/A					Pass
14	With PV	5	0	48	2:45	3:08	4:01	8	7:08	4:33	4:52	5:27	5:38	5:54	6:19	Fail
15	NC	5	0	48	2:30	NR	3:02	8	5:58							Fail
15	NC	5	0	52	2:10	2:40	3:05	8.5	5:58							Fail
17	With PV	5	10	48	2:51	NR	3:39	4	10:00							Pass
Tests conducted June 7, 2012																
14	2 PV, 12" apart	5	10	24	2:48	2:50	2:51	6.5	4:04							Fail

NR = Not Recorded

NC = Noncombustible

LSFR EPDM over 4" Poly iso

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Figure 1 – Figure Illustrating Flame Spread of System 14 - Low Slope Roof / PV Module LSFR EPDM, 5” Gap, 0° Inclination and 48” Offset Experiment

Figure 2 – Figure Illustrating Flame Spread of System 15 - Low Slope Roof / Noncombustible PV Surrogate LSFR EPDM, 5” Gap, 0° Inclination and 48” Offset Experiment

Figure 3 – Figure Illustrating Flame Spread of System 15 - Low Slope Roof / Noncombustible PV Surrogate LSFR EPDM, 5” Gap, 0° Inclination and 52” Offset Experiment

Figure 4 – Figure Illustrating Flame Spread of System 17 - Low Slope Roof / Noncombustible PV Surrogate LSFR EPDM, 5” Gap, 10° Inclination and 48” Offset Experiment

Figure 5 – Figure Illustrating Flame Spread of System 14 - Low Slope Roof / 2 PV Modules LSFR EPDM, 5” Gap, 10° Inclinations and First Module 24” Offset, Second Module Spaced 12” Experiment

Steep Slope Results

Ten experiments were conducted on steep slope roofs constructed using Class A, 3 tab shingles produced by three different manufacturers. Maximum flame spread distances and the corresponding time at which they occurred for the various steep slope roof assembly experiments are listed in Table 2. Two baseline experiments without PV modules present were conducted on shingle manufacturer 1, and single baseline experiments were conducted on the remaining two shingles, manufacturers 2 and 3. All baseline experiments without the PV modules present demonstrated flame spread along the roof surface of approximately 4 ft (Class A compliant).

When a noncombustible PV surrogate was installed at a gap height of 5 in. and an offset of 36 in., the flame spread along the roof extended to 4 ft. (Class A compliant). When a noncombustible PV surrogate was also installed at a gap height of 5 in. and an offset of 24 in., the flame spread along the roof extended to 8 ft (noncompliant Class A).

Two experiments were conducted with aluminum framed, glass on polymer PV modules installed at a gap of 5 in, an offset of 42 in., and parallel to the roof (0° inclination). For the experiment conducted with manufacturer 1, shingles resulted in a flame spread of 3.5 ft (Class A compliant), and the second experiment conducted with shingles from manufacturer 3 resulted in a flame spread of 4 ft (Class A compliant). Two additional experiments were conducted with the modules installed at an offset of 36 in. The experiment conducted with shingles from manufacturer 1 developed a flame spread of 4 ft, (Class A compliant), and manufacturer 3 developed a flame spread of 4.5 ft. (Class A compliant)

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Table 2 - Summary of Repositioning Experiments – Steep Slope

								Roof						PV						
				Gap		Module		e of Roof Flame Spr			Max. Flame Spread			Time of PV Underside Flame Spread						
System		Shingle	System	Height	Angle	Offset		3.0'	3.5'	4.0'	Distance	Time		Ignition	1'	2'	3'	4'	Full Panel	
#	Slope	Material	Notes	(in)	(deg)	(in)		(m:s)	(m:s)	(m:s)	(ft)	(min:sec)		(m:s)	(m:s)	(m:s)	(m:s)	(m:s)	(m:s)	Pass/Fail
Tests conducted June 6, 2012																				
11	Steep	Mfg 3	Baseline	N/A	N/A	N/A		6:31	7:12	8:04	4	10:00		N/A	N/A					Pass
1	Steep	Mfg 1	Baseline	N/A	N/A	N/A		4:16	5:04	8:42	4	10:00		N/A	N/A					Pass
4	Steep	Mfg 2	Baseline	N/A	N/A	N/A		4:41	6:07	7:04	4	10:00		N/A	N/A					Pass
6	Steep	Mfg 1	PV	5	0	42		5:18	7:03	NR	3.5	10:00								Pass
Tests conducted June 7, 2012																				
6	Steep	Mfg 3	PV	5	0	42		6:10	NR	7:20	4	10:00		7:55	8:30					Pass
2	Steep	Mfg 1	PV	5	0	36		7:01	8:11	8:49	4	10:00								Pass
3	Steep	Mfg 1	NC	5	0	36		5:00	5:48	7:15	4	10:00		N/A						Pass
7	Steep	Mfg 2	NC	5	0	24		4:16	4:36	5:13	8	7:01		N/A						
8	Steep	Mfg 3	PV	5	0	36		4:08	4:53	5:41	4.5	10								
9	Steep	Mfg 1	Baseline	NA	NA	NA		5:33	6:11	7:11	4	10		N/A	N/A					Pass

NA = Not Applicable
NC = Noncombustible module surrogate

Figure 6 – Figure Illustrating Flame Spread of System 6 – Steep Slope Roof / PV Module Mfg. #1 Shingle, 5” Gap, 0° Inclination and 42” Offset Experiment

Figure 7 – Figure Illustrating Flame Spread of System 6 – Steep Slope Roof / PV Module Mfg. #3 Shingle, 5” Gap, 0° Inclination and 42” Offset Experiment

Figure 8 – Figure Illustrating Flame Spread of System 2 – Steep Slope Roof / PV Module Mfg. #1 Shingle, 5” Gap, 0° Inclination and 36” Offset Experiment

Figure 9 – Figure Illustrating Flame Spread of System 3 – Steep Slope Roof / Noncombustible PV Surrogate Mfg. #1 Shingle, 5” Gap, 0° Inclination and 36” Offset Experiment

Figure 10 – Figure Illustrating Flame Spread of System 7 – Steep Slope Roof / Noncombustible PV Surrogate Mfg. #2 Shingle, 5” Gap, 0° Inclination and 24” Offset Experiment

Figure 11– Figure Illustrating Flame Spread of System 8 – Steep Slope Roof / PV Module Mfg. #3 Shingle, 5” Gap, 0° Inclination and 36” Offset Experiment

Summary and Recommendations

Summary of Findings

Although the experiments conducted for this report are not exhaustive, an analysis of the generated data point to the following key findings:

Low slope:

- The low slope roof baseline experiment (no PV) exhibited a flame spread of 60 inches.
- Both a noncombustible representation of a PV module or a Class C PV module mounted parallel to and at an elevation of 5 inches above the roof and at offsets of 48 and 52 inches flame spreads were in excess of Class A performance requirements.
- A PV module mounted at a slight inclination (10°) to and at an elevation of 5 inches above the roof and at a 48 inch offset did comply with Class A requirements.
- A single experiment conducted with two modules angled to the roof (10° inclination), the first offset 24 inches and the second space 12 inches from the first did not comply with Class A requirements.
- The overall results of low slope tests with the PVs present were fairly consistent with tests using a surrogate noncombustible PV .

Steep slope:

- The steep slope roof baseline experiments (no PV) exhibited a flame spread of 48 inches.
- A noncombustible representation of a PV module mounted parallel to and at an elevation of 5 inches above the roof with an offset of 42 inches complied with Class A requirements.
- Two experiments conducted with PV modules mounted parallel to and at an elevation of 5 inches above the roof with an offset of 42 inches complied with Class A requirements.
- Two experiments conducted with PV modules mounted parallel to and at an elevation of 5 inches above the roof with an offset of 36 inches complied with Class A requirements.
- An additional experiment was conducted with a noncombustible sheet mounted parallel to and at an elevation of 5 inches above the roof with an offset of 24 inches and did not comply with Class A requirements
- The overall results of steep slope tests with the PVs present were fairly consistent with tests using a surrogate noncombustible PV .

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Recommendations

Based on the research study findings, the repositioning approach of examining the first item ignited (roof) and then the second item ignited (PV), was a viable method for assessing the performance of a roof / PV combination. It was observed that this method was of such severity that currently commercially available PV Class C modules would likely have to be modified, or the installation details specified, in order to yield compliant results for both low and steep slope tests. It is important to note that the results of tests with the PVs present were fairly consistent with tests using a surrogate noncombustible PV .

Consequently, the Research Team as well as a focus group present to observe some of these tests supported the following recommendations and suggestions to propose revisions to UL 1703 as follows:

Spread-Of-Flame Tests to be conducted:

- Individually with the module mounted on a noncombustible deck and oriented such that the ignition flame is directed on the top surface of the module or panel.
- With the module installed on a steep slope and low slope roofs as an assembly and oriented such that the ignition flame is directed into the interstitial space below the module and above the roof. The module or panel installation shall be installed:
    a. with a 36 inch (0.91 m) between the edge of the flame test apparatus and the edge of the PV mounting system for steep sloped roofs,
    b. with 42 inch (1.07 m) between the edge of the flame test apparatus and the edge of the PV mounting system for low sloped roofs.

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Effect of Rack Mounted Photovoltaic Modules on the Fire Classification Rating of Roofing Assemblies
Phase 2

Project Number: 10CA49953
File Number: IN15911
Date: January 30, 2012

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EXECUTIVE SUMMARY

The subject of this report is a second phase continuation of a research project conducted to determine the effect of rack mounted photovoltaic (PV) systems on the flammability classification rating of roofing materials. The original Phase 1 of the project was conducted in response to fire and building code officials' interest in determining if a Class C rated module would reduce the fire resistance performance and/or fire rating of some Class A rated roof systems. And if so, which roof systems are impacted and to what extent.

An analysis of the data generated by the experiments carried out in the first study [1]pointed to the following key findings:

- The presence of a rack mounted PV module on a roof has an adverse effect on the fire performance of the roof regardless of the fire rating of the roof or the Class rating of the PV panel based on Spread of Flame test method described in UL 790 *Standard for Safety for Standard Test Methods for Fire Tests of Roof Coverings*, Eighth Edition, dated April 22, 2004 and UL 1703, *Standard for Safety for Flat-Plate Photovoltaic Modules and Panels*, Third Edition, Dated March 15, 2002,

- The extent of the degradation on fire performance with respect to flame spread of a roof depends upon PV installation parameters such as setback distance and separation gap between roof and PV module,

- The presence of a rack mounted PV module on a roof could adversely affect the fire performance of the roof when subjected to burning brands placed on the roof based on the Burning Brand test method described in UL 790.

[1] Effect of Rack Mounted Photovoltaic Modules on the Flammability of Roofing Assemblies, Date: September 30, 2009, Revised March 5, 2010

This second phase of the project further investigated rack mounted PV modules on roof decks to determine:

- The effect of PV modules mounted at angles (positive and negative) to steep and low sloped roofs,
- The impact of PV modules mounted at zero clearance to the roof surface with the ignition source directed in the plane of the roof or the plane of the PV surface,
- Heat release rate and transfer to roof surface of Class A, B, C brands and common materials such as leaf debris and excelsior (wood wool).

Continuation of Fire Safety Research Project

This project was conducted to expand on previous empirical data for consideration by manufacturers of PV and roofing products, regulatory officials such as Authorities Having Jurisdiction, code and standards development organizations. It is anticipated that the results of these experiments will lead to potential code and standards revisions.

Summary of Findings

Based on this series of experiments, the following findings were determined:

- Some PV modules mounted at angles (positive and negative) to steep and low sloped roofs impacted the fire classification rating of the supporting roof assembly. The extent of the impact was dependent on the angle of the module relative to the roof and the type of roofing system,
- PV modules mounted at zero clearance to the roof surface demonstrated no impact to the fire rating of the roof when the ignition source flame was directed to the front vertical surface of the module or when the ignition source flame was directed along the horizontal face of the module,
- The heat release rate and heat transfer to the roof surface of Class A and Class C brands did not demonstrate a direct correlation to common materials that may collect between PV modules and the roof surface, such as leaf debris and excelsior (wood wool). The Class A brand yielded results significantly greater than the leaf debris and wood excelsior while the Class B brand yielded results significantly less than the leaf debris and wood excelsior. While the Class B brand was not included in the experiments, the deduction of these experiments is that the representation of common materials is closest to the Class B brand in terms of heat release and heat transfer to the roof surface.

Acknowledgments

The authors would like to acknowledge the following individuals for their contributions including guidance and support for this project:

Bill Brooks of Brooks Engineering
Larry Sherwood of Sherwood Associates
Kevin Lynn of the Department of Energy (DOE)
Andy Rosenthal of New Mexico State University

1. TABLE OF CONTENTS

EXECUTIVE SUMMARY 2
Continuation of Fire Safety Research Project 3
Summary of Findings 3
Acknowledgments 3
Introduction 5
Task 1 – PV Arrays Installed at Various Angles to the Roof and at Zero Clearance 5
Objectives and Technical Plan 5
Samples 5
Experimental 6
Results 8
Task 1 - Summary 20
TASK 2 – Demonstration Comparisons of Class A and Class C Brands 21
Objective 21
Samples 21
Experimental 21
Task 2 - Summary 43
SUMMARY AND RECOMMENDATIONS 44
SUMMARY OF FINDINGS 44
RECOMMENDATIONS 44

Introduction

This research project described herein expands on work conducted in Phase 1. Phase 1 of this project sought to address regulatory concerns over the installation of Class C fire rated PV modules over Class A fire rated roofs. As such, the work concentrated on PV arrays installed in a most critical geometry – modules installed parallel to the roof at critical installation heights above the roof (such as 5 inches). Subsequently, interest was expressed in characterizing the effect of arrays installed at various angles to the roof. There was also interest in understanding the effect of flame spread with the ignition source impinging at the top surface of the PV panel (PV surface plane) mounted at 0 in. clearance installation height above the roof.

In addition, the Phase 1 work led to questions on the comparison of the UL790 Class A and C brands, as used in the Phase 1 experiments, to common materials that may collect between PV modules and the roof surface. These common materials were represented by leaf debris and wood excelsior (wood wool). A basic demonstration comparison of Class A versus Class C burning brands was conducted. Heat release rate and transfer to the roof of Class A and C brands as well as common materials, represented by leaf debris and excelsior (wood wool), was recorded.

Task 1 – PV Arrays Installed at Various Angles to the Roof and at Zero Clearance

Objectives and Technical Plan

The objective of this task was to conduct experiments on a variety of PV module/roof combinations to demonstrate how PV modules installed above the roof at various angles impacts the fire classification rating of a roof system.

The technical plan consisted of conducting UL 790 / UL1703 flame spread experiments on the low and steep slope roofs PV modules installed at angles positive and negative to the roof.

Samples

Assemblies used in these experiments were constructed using PV modules donated by industry and roofing products obtained from local retailers. The PV modules were of a metal framed glass on polymer design, representative of Class C fire classification rating. Class A steep slope roofs were constructed with 3 tab shingles installed over typical roofing felt on a combustible deck. For the steep slope roof assemblies, the roof was inclined to horizontal at a 5 / 12 pitch.

Class A low slope roofs were constructed with a single ply FR EPDM (ethylene propylene diene monomer), 60 mil thickness membrane mechanically fastened to a noncombustible deck. One experiment was conducted with single ply FR EPDM (ethylene propylene diene monomer), 60 mil thickness membrane installed, over a single layer of polyisocyanurate (iso) insulation board and mechanically fastened to a noncombustible deck. For the low slope roof assemblies, the roof was flat (0 pitch).

Experimental

The fire performance systems of PV modules on roof deck assemblies were investigated as described in UL 790 / UL 1703 Spread of Flame tests. For the spread of flame test, the roofing material and the PV fire rating were as noted with the angle of the module being the experimental parameter of interest (Table 1). With the exception of experimental systems 2 and 11, the ignition source flame was directed into the gap formed between the top of the roof surface and the bottom of the PV module. Figure 1 illustrates the PV / roof assembly combinations and ignition flame impingement.

Figure 1 – Figures Illustrating Positive and Negative Angles, and Ignition Source Impingement Points

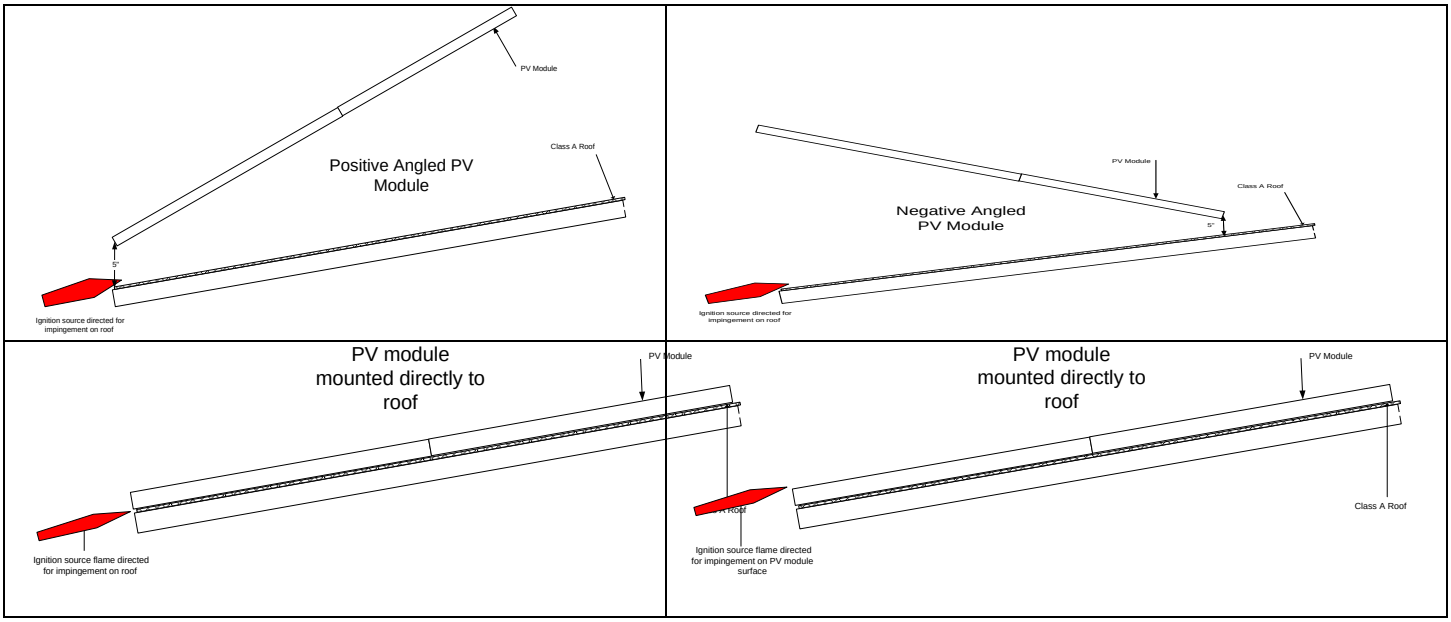

Table 1 Experiment PV Module and Roof Sample Details

System	Test	Roof		Panel	Installation		Comments	Flame Impingement
		Type	Class	Class	Gap, in.	Angle		
PV Modules Mounted Directly on Deck								
1	Spread of flame	Shingle 3 - 3 tab	A	C	0	Standard 5/12	PV over roof - no air gap	Roof level
2	Spread of flame	Shingle 3 - 3 tab	A	C	5	Standard 5/12	PV over roof - no air gap	Flame @ top of module
Variations of PV Inclination to Roof Slope								
3	Spread of flame	membrane*	A	C	5	Standard 0	PV parallel (flat)	Roof level
4	Spread of flame	membrane*	A	C	5	Standard 0	positive tilt 22 degrees	Roof level
5	Spread of flame	membrane*	A	C	5	Standard 0	positive tilt 45 degrees	Roof level
6	Spread of flame	membrane*	A	C	5	Standard 0	negative tilt 22 degrees	Roof level
7	Spread of flame	membrane**	A	C	5	Standard 0	negative tilt 22 degrees	Roof level
8	Spread of flame	Shingle 3 - 3 tab	A	C	5	Standard 5/12	PV parallel	Roof level
9	Spread of flame	Shingle 3 - 3 tab	A	C	5	Standard 5/12	positive tilt 22 degrees	Roof level
10	Spread of flame	Shingle 3 - 3 tab	A	C	5	Standard 5/12	negative tilt 22 degrees	Roof level
11	Spread of flame	Shingle 3 - 3 tab	A	C	5	Standard 5/12	PV parallel	Flame @ top of module

Notes:

*- Single ply EPDM (ethylene propylene diene monomer), 60 mil membrane, mechanically fastened to a noncombustible deck

** - Single ply EPDM (ethylene propylene diene monomer), 60 mil membrane, over a single layer of “iso” insulation board mechanically fastened to a noncombustible deck

Results

Spread of flame test results are shown in Table 2:

Table 2 Spread of Flame Test Results

System	Roof Type	Comments	Flame Impingement	Flame Spread Data			
				Roof		PV	
				Distance (feet)	Time (min:sec)	Distance (feet)	Time (min:sec)
PV Modules Mounted Directly on Deck							
1	Shingle 3 - 3 tab	PV over roof - no air gap	Roof level			0.5	7:47
2	Shingle 3 - 3 tab	PV over roof - no air gap	Flame @ top of module			3.5	9:54
Variations of PV Inclination to Roof Slope							
3	membrane*	PV parallel (flat)	Roof level	> 8.5	1:17	Same	
4	membrane*	positive tilt 22 degrees	Roof level	> 8.5	1:21	Same	
5	membrane*	positive tilt 45 degrees	Roof level	4.5	1:55	> 8.5 [1]	1:55
6	membrane*	negative tilt 22 degrees	Roof level	4.5	9:07	No Propogation	
7	membrane**	negative tilt 22 degrees	Roof level	> 8.5 [2]	2:20	Same	
8	Shingle 3 - 3 tab	PV parallel	Roof level	> 8.5	2:01	Same	
9	Shingle 3 - 3 tab	positive tilt 22 degrees	Roof level	5 [3]	4:18	4	4:18
10	Shingle 3 - 3 tab	negative tilt 22 degrees	Roof level	4.5 [4]	7:02	No Propogation	
11	Shingle 3 - 3 tab	PV parallel	Flame @ top of module	3.5 [5]	8:43	6	8:43

Notes:
* - denotes sample constructed with single ply FR EPDM (ethylene propylene diene monomer), 60 mil, mechanically fastened to a noncombustible deck
** - denotes sample constructed with single ply FR EPDM (ethylene propylene diene monomer), 60 mil, over a single layer of "iso" insulation board, mechanically fastened to a combustible deck
> - denotes flames observed beyond reported value, typically beyond the end of the Class C deck - 13'
1 - propagation along roof surface 4.5', propagation on the underside of PV modules greater than 10'
2 - propagation along roof surface beyond 13', propagation on the underside of PV modules ~ 4.5 from the end mounted 5" above the roof deck
3 - propagation along the underside of the PV module - 4' Note: PV panel fell prior to conclusion of experiment
4 - no fire propagation along the underside of the PV module - did not ignite
5 - PV glass panel fell to roof deck @ 7:40

Zero Clearance Experiments: - In both of the experiments where the modules were mounted directly to the roof surface, the flame propagation of the PV / roof assembly met the requirements of Class A.

Low Slope Experiments:

- For systems 3 and 4, experiments which incorporated a single layer of membrane roof material mounted directly to a noncombustible deck (with no insulation), with the PV module elevated 5” above the roof and at angles with a positive tilt of 0° (parallel to the roof) and 22°, flame propagation along both the roof and the underside of the modules were in excess of the 6 foot maximum flame propagation. These system results did not meet the requirements of Class A,
- For system 5, at a positive tilt 45° angle, the flame propagation along the roof was less than 6 feet, but the flame propagation along the underside of the modules exceeded 6 feet,

- For the same configuration, but with the PV modules at a negative tilt 22° angle opposite of the roof (system 6), the fire propagation along the roof met the requirements of Class A. For this experiment, there was no flame propagation along the nderside of the modules,
- However, for this same basic configuration with a single layer of 2" polyisocyanurate insulation added beneath the membrane, system 7, the fire propagation along both the roof and the underside of the PV modules exceeded 6 feet and did not meet the requirements of Class A.

So, the inclusion of a typical layer of insulation used in low-slope roofs increased the fuel of the roof assembly resulting in noncompliant flame spread in less than 2 ½ minutes. It should be noted that for systems 3 through 6 experiments, flames were extinguished and the experiment was terminated prior to the prescribed 10 minute test duration as the flame had propagated beyond the end of the roof deck.

Steep Slope Experiments:

- For the experiment, system 8, which incorporated a 3 tab shingle material mounted over roofing felt and fastened to a combustible deck, with the PV module elevated 5" above the roof and at angles with a positive tilt of 0° (parallel to the roof), flame propagation along both the roof and the underside of the modules exceeded 6 feet and did not meet the requirements of Class A,
- For the same configuration but at a 22° angle positive to the roof, system 9, the flame propagation along both the roof and the underside of the PV module met the requirements of Class A. It should be noted that the PV module collapsed prior to the end of the test,
- With the PV modules mounted at a 23° angle negative to the roof, system 10, the flame propagation along both the roof and the underside of the module met the requirements of Class A,
- The final experiment, system 11, was conducted with ignition source directed to the top surface of the PV module mounted elevated and parallel to the roof. Under this configuration the flame propagation along both the roof and the PV module met the requirements of Class A. It should be noted that the PV module glass superstrate fell to the roof surface at 7:40.

Visual results are provided in the following photographs. Please note, the photographs were taken during various times of the experiment and do not represent maximum fire propagation as noted in Table 2.

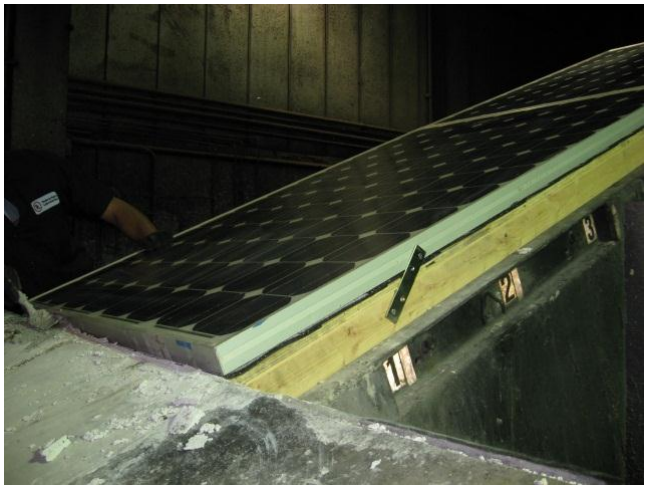

Figure 2 – System 1 Spread of Flame Experiment with PV Modules Mounted Directly to Shingled Deck, Ignition Source Directed at Roof Surface Set Up

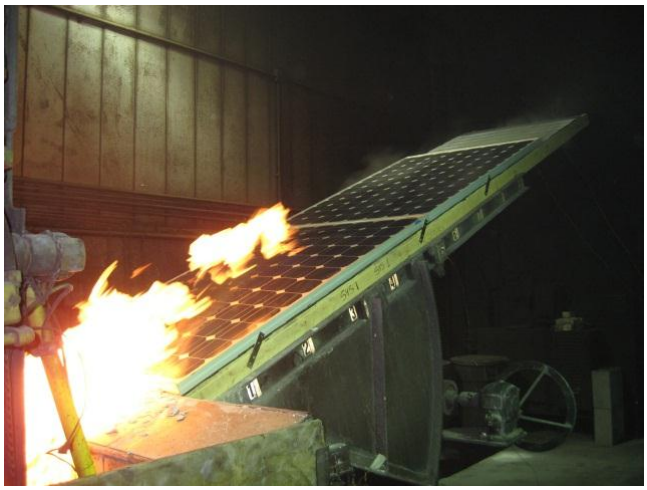

Figure 3 –System 1 Spread of Flame Experiment with PV Modules Mounted Directly to Shingled Deck, Ignition Source Directed at Roof Surface

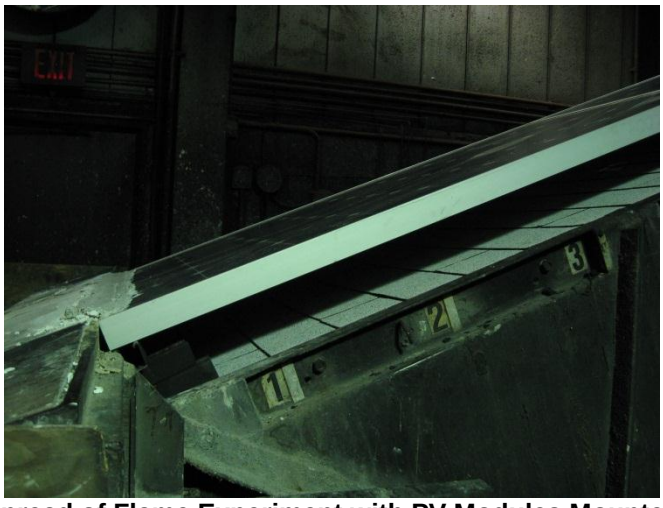

Figure 4 – System 2 Spread of Flame Experiment with PV Modules Mounted Directly to Shingled Deck, Ignition Source Directed at PV Superstrate Surface Set Up

Figure 5 – System 2 Spread of Flame Experiment with PV Modules Mounted Directly to Shingled Deck, Ignition Source Directed at PV Superstrate Surface

Figure 6 – System 3 Spread of Flame Test PV with Module Mounted Parallel to Low Sloped Roof, 5” Gap Set Up

Figure 7 – System 3 Spread of Flame Test PV with Module Mounted Parallel to Low Sloped Roof, 5” Gap

Figure 8 – System 4 Spread of Flame Test PV with PV Module Mounted 22° to Low Sloped Roof (Positive) Set Up

Figure 9 – System 4 Spread of Flame Test PV with PV Module Mounted 22° to Low Sloped Roof (Positive)

Figure 10 – System 5 Spread of Flame Test PV with PV Module Mounted 45° to Low Sloped Roof (Positive) Set Up

Figure 11 – System 5 Spread of Flame Test PV with PV Module Mounted 45° to Low Sloped Roof (Positive)

Figure 12 – System 6 Spread of Flame Test PV with PV Module Mounted 45° to Low Sloped Roof (Negative) Set Up

Figure 13 – System 6 Spread of Flame Test PV with PV Module Mounted 45° to Low Sloped Roof (Negative)

Figure 14 – System 7 Spread of Flame Test PV with PV Module Mounted 22° to Low Sloped Roof with 2" Polyisocyanurate Foam (Negative) Set Up

Figure 15 – System 7 Spread of Flame Test PV with PV Module Mounted 22° to Low Sloped Roof with 2" Polyisocyanurate Foam (Negative)

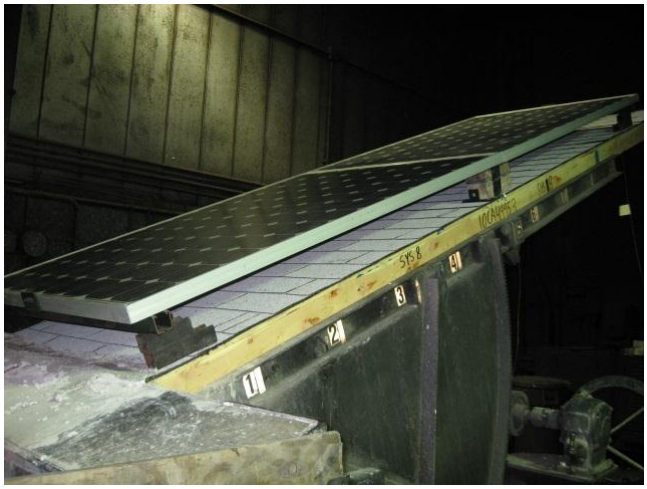

Figure 16 – System 8 Spread of Flame Test PV Module Mounted Parallel to Steep Sloped Roof, 5" Gap Set Up

Figure 17 – System 8 Spread of Flame Test PV Module Mounted Parallel to Steep Sloped Roof, 5" Gap

Figure 18 – System 9 Spread of Flame Test with PV Module Mounted 22° to Steep Sloped Roof (Positive) Set Up

Figure 19 – System 9 Spread of Flame Test with PV Module Mounted 22° to Steep Sloped Roof (Positive)

Figure 20 – System 10 Spread of Flame Test with PV Module Mounted 22° to Steep Sloped Roof (Negative) Set Up

Figure 21 – System 10 Spread of Flame Test with PV Module Mounted 22° to Steep Sloped Roof (Negative)

Task 1 - Summary

The following is a summary of the results:

- PV arrays mounted at zero clearance to the roof surface, with the ignition source directed towards the plane of the roof, or the plane of the PV surface, do meet the requirements of Class A flame spread performance,

- PV arrays mounted on representative low slope membrane roof coverings at initial heights of 5 inches above the roof and parallel, and at positive angles of 22° and 45° did not meet the requirements of Class A flame spread performance,

- PV arrays mounted on representative low slope membrane roof coverings at initial heights of 5 inches above the roof and at a negative angle of did meet the requirements of Class A flame spread performance with no polyisocyanurate foam. However, when the same construction employed polyisocyanurate foam, the construction did not meet the requirements of Class A flame spread performance,

- PV arrays mounted on representative steep slope constructions with 3 tab shingles at initial heights of 5 inches above the roof and parallel to the roof did not meet the requirements of Class A flame spread performance.

- PV arrays mounted on representative steep slope constructions with 3 tab shingles at initial heights of 5 inches above the roof and at both positive and negative tilt angles of 22° to the roof did meet the requirements of Class A flame spread performance.

Overall, these experiments demonstrated that PV arrays mounted at various positive and negative angles to the roof with an initial elevation of 5 inches above the roof can, in some cases, affect the Class A performance of low or steep slope roofs. These experiments demonstrated that PV arrays mounted at zero clearance to the roof surface, with the ignition source directed towards the plane of the roof, or the plane of the PV surface, do meet the requirements of Class A flame spread performance.

Other installation parameters including low slope insulation thickness and formulations such as polystyrene and initial elevations would provide a more complete understanding of PV / roof assembly fire classification performance.

TASK 2 – Demonstration Comparisons of Class A and Class C Brands

Objective

The burning brand test conducted in UL 790 / UL 1703 is intended to evaluate roofing assemblies to resist the penetration of fire through the assemblies into spaces underneath, such as a cockloft or attic. The objective of this task was to demonstrate the burning behaviors of the standard Class A and C roofing brands, as well as common materials that may collect between the PV modules and the roof surface, represented by wood excelsior and leaves. Temperatures of a noncombustible roof deck were measured directly under the burning item or material to illustrate the heat transfer to roofing materials. In addition, the weight of the burning item / material and the peak heat release rate was also measured. This data was provided to contrast the different fuel packages.

These demonstrations were not intended as a detailed study to compare the heat transfer or thermal stress imposed on a roof.

Samples

Samplers consisted of wood frames with a single ¼ inch thick noncombustible deck. In the final experiment, a roof deck assembly was constructed in accordance with UL 790 Burning Brand test with 3 tab shingles and a 15 lb. felt underlayment. The shingles were purchased from a local building supply retailer and were marked as Class A compliant. In both instances, the roofs were inclined to horizontal at a 5 / 12 pitch.

Experimental

These experiments were conducted under a oxygen consumption product calorimeter using the basic test methods from UL 790 burning brand test. UL 790 specifies an airflow rate of 12 mph or 1056 ft/min over the surface of the roof sample. Forced ventilation of the brand ranged from 0, 350, and 700 ft/min measured in the plane and at the leading edge of the roof. The airflow for these demonstrations was reduced from the standard in order to capture the combustion products for measurement of heat release rate in an oxygen consumption calorimeter. Standard Class A and Class C brands were ignited using the procedure outlined in UL 790. Once ignited, the burning brand was placed on a noncombustible deck which incorporated a thermocouple to measure the temperature of the deck surface. In addition, a single experiment was conducted on a shingled wood deck where temperatures of the exposed surface of the shingle, roofing felt, and unexposed surface of the deck were measured.

For the debris experiments, excelsior and leaf fuel package volumes were established to be the same overall size as the Class A brand. The debris material was ignited with a small open flame. The airflow was set at 350 ft/min for these experiments due to the tendency of the excelsior fibers and leaves to become dislodged and blown off the deck at 700 ft/min.

Results

The results of the experiments are shown in Table 2.

Table 2 Burning Brand/Debris Fire Experiments Results

System	Heat Source	Dimensions (LxWxH) (in)	Condition	Weight (g)	Air Flow (f/min)	Heat Release Peak (kW)	Heat Release Total (MJ)	Deck Bottom (°C)	Deck Top (°C)	Felt (°C)	Shingle (°C)
1	A Brand	12X12X2.5	Assembled	1930	700	70	35.3		1152		
2	A Brand	12X12X2.5	Assembled	1930	0	46	37.8		938		
3a	C Bramd	1.5X1.5X.75	Assembled	11	700	6*	0.6*		274		
3b	C Brand	1.5X1.5X.75	Assembled	11	700	4*	0.3*		216		
3c	C Brand	1.5X1.5X.75	Assembled	11	700	5*	0.8*		614		
4	Excelsior	12X12X5	Fluffed	-	0	57	2.8		548		
5	Leaves	12X12X5	Fluffed	141	0	5*	0.3		507		
6	Excelsior	12X12X5	Fluffed	78	0	44	2.9		264		
7	Excelsior	12X12X5	Compressed	990	0	48	20.7		691		
8	Leaves	12X12X5	Fluffed	181	350	10*	2.8		724		
9	Excelsior	12X12X5	Compressed	1204	350	95	20.4		841		
10	Excelsior	12X12X5	Fluffed	54	350	126	2.8		384		
11	A Brand	12X12X2.5	Assembled	1968	700	82	40.9	198	565	583	807

Notes:
* - Measured Heat Release Rate at the lower threshold of the instrument measurement.

A review of the data indicates an increase in heat release and associated deck surface temperature due to forced ventilation or airflow into the fuel package. This result is expected, since the burning rate is directly related to the amount of oxygen available to the fire. As noted earlier, the maximum airflow used during these experiments was approximately ¾ of the 12 mph (1056 ft/min) as outlined in UL 790. The airflow velocity was reduced from that specified in the standard due to the need to use an appropriately sized calorimeter to measure the relatively low heat release rates (~ 10 to 100 kW) and capture the combustion products. It is reasonable to expect higher heat release rates at the standard 12 mph velocity.

The heat release rate of the Class C brand was substantially lower than the Class A brand both in peak (~5 vs 70 kW) and total energy generated (~0.8 vs 35 MJ). This is also an expected result given the differences in mass, construction and geometry.

For the experiments with wood excelsior and leaf debris, the volumes were arranged and established to be the same as the Class A brand. The airflow was set at 350 ft/min for these experiments due to the tendency of the excelsior fibers and leaves to become dislodged and blown off the deck at 700 ft/min. When compressed, the excelsior fuel package was slightly more than ½ of the weight of the Class A brand. The excelsior generated a peak heat release rate of 95 kW as compared to the brand's 70 kW. The resulting deck surface temperature was 841 °C with the excelsior as compared to 1152 °C for the brand. When fluffed, the weight was approximately 3% of the brand, but generated a greater peak heat release rate (123 kW compared to 70 kW). The exposed deck surface temperature was significantly less (384 °C vs 1152 °C). All leaf experiments were conducted in the 'fluffed' condition as this material, unlike the excelsior would not remain in a compressed form. With a 350 ft/min ventilation condition, the heat release rate of 10 kW was at the low end of the product calorimeter's capability to measure. The deck's surface temperature was 724 °C.

A single test of a Class A brand placed on a shingled, combustible deck generated 82 kW. The exposed surface temperature of the shingle was 807 °C, the roofing felt layer was 583 °C and the surface temperature of the underside of the roof deck was 198 °C.

Visual results are provided in the following Figures 21 through 29. Please note: the photographs were taken during various times of the experiment and do not represent maximum fire propagation as noted in Table 3.

Plots of the temperature and heat release rates recorded during the experiments are shown in Figures 30 through 59.

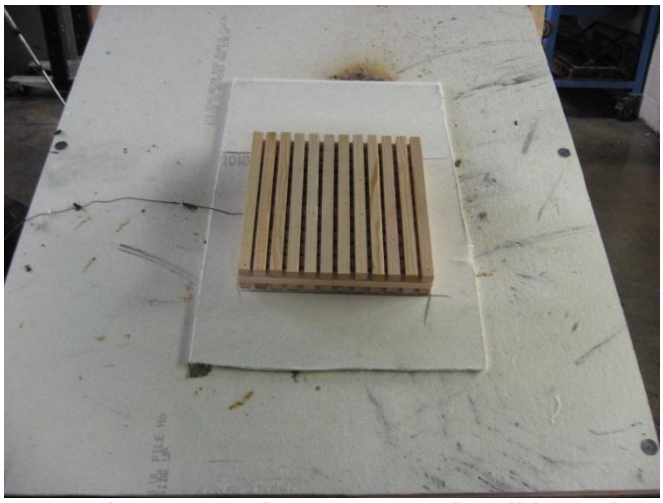

Figure 22 - Class A Brand Over Noncombustible Deck Set Up

Figure 23 - Class A Brand Over Noncombustible Deck

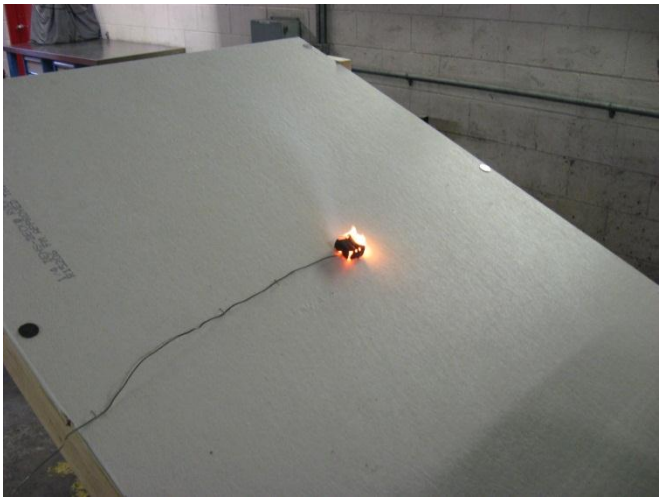

Figure 24 - Class C Brand Over Noncombustible Deck

Figure 25 - Class Wood Excelsior Over Noncombustible Deck Set Up

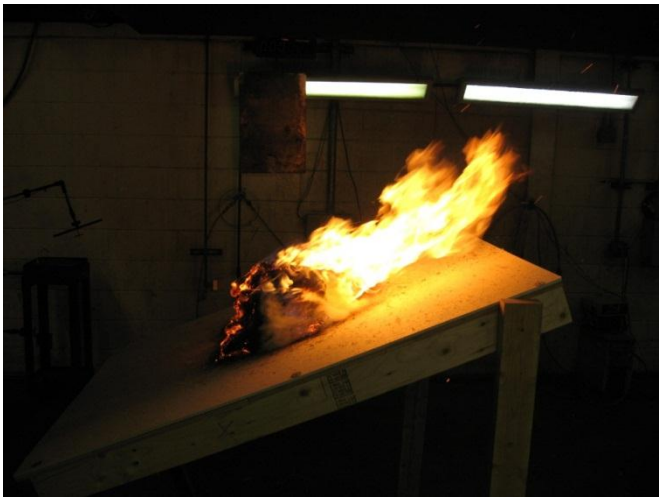

Figure 26 - Class Wood Excelsior Over Noncombustible Deck

Figure 27 - Leave Debris Over Noncombustible Deck Set Up

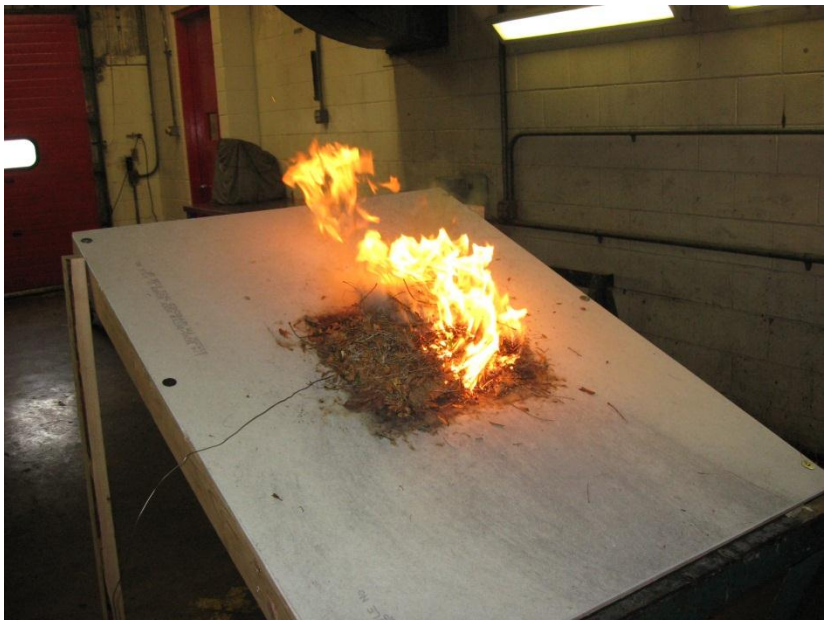

Figure 28 - Leave Debris Over Noncombustible Deck

Figure 29 - Class A Brand Over Shingled Combustible Deck

Figure 30 - Unexposed Surface of Combustible Deck

Test #, sample description, air flow & temperature and HRR plots.

Test 1 - Sample=A Brand - Instrumented Roof Deck - 700 fpm

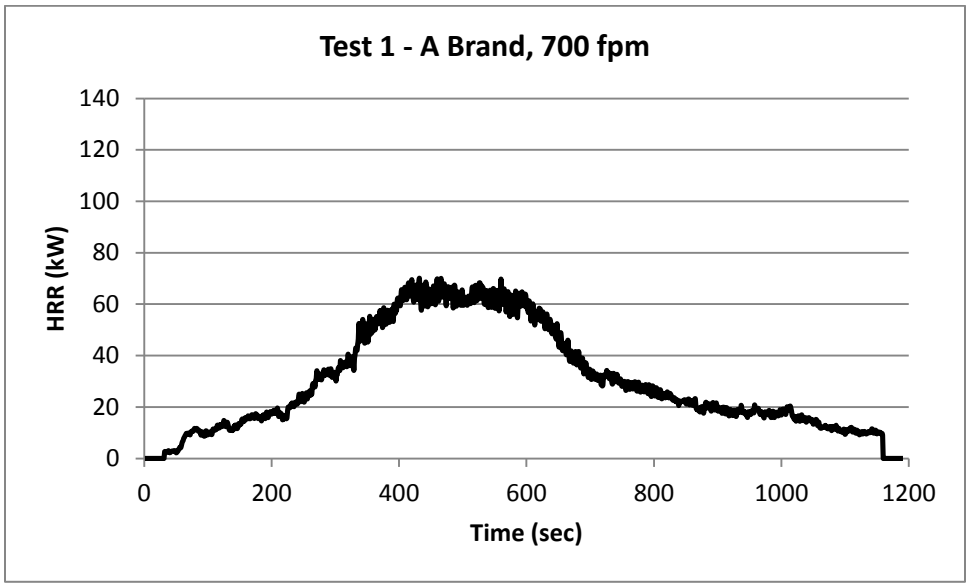

Figure 31 - Graph of Heat Release Rate (HRR) in kilowatts

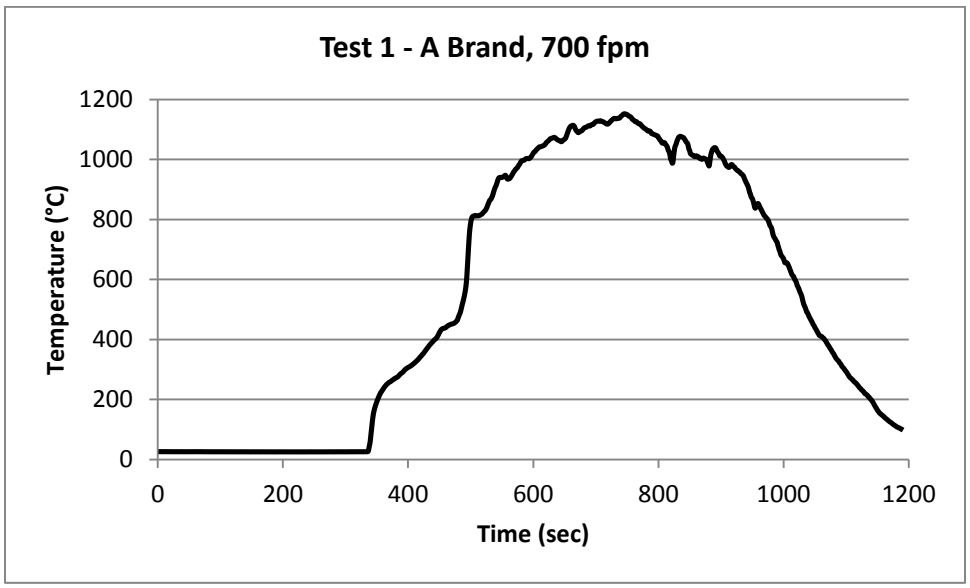

Figure 32 - Graph of Deck Surface Temperature (°C)

Test 2 - Sample=A Brand - Instrumented Roof Deck - 0 fpm

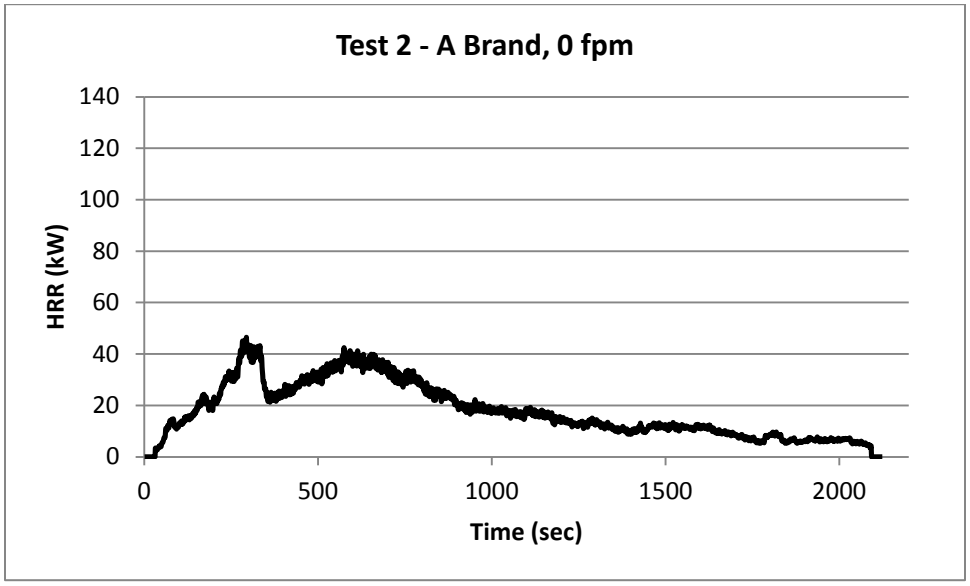

Figure 33 - Graph of Heat Release Rate (HRR) in kilowatts

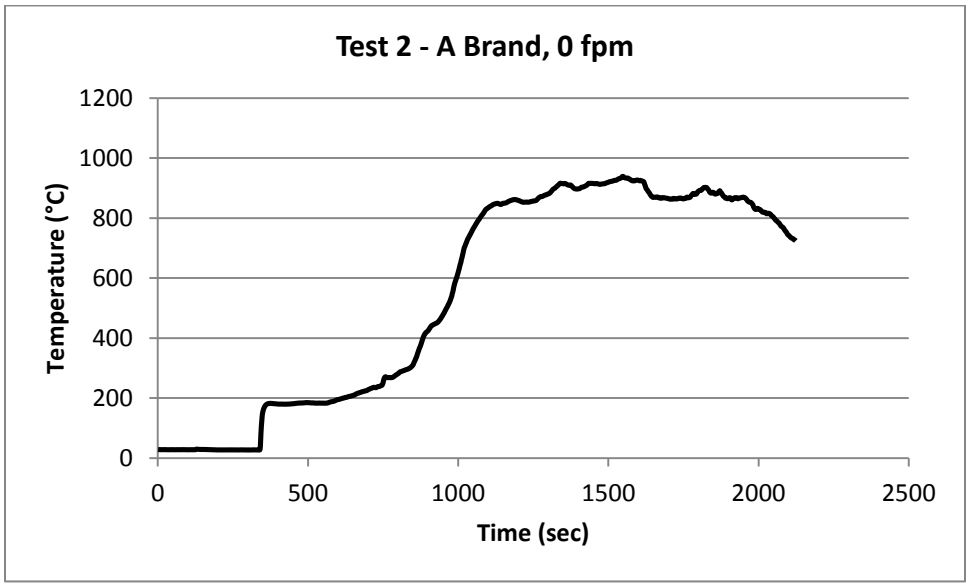

Figure 34 - Graph of Deck Surface Temperature (°C)

Test 3A - Sample=C Brand - Instrumented Roof Deck - 700 fpm

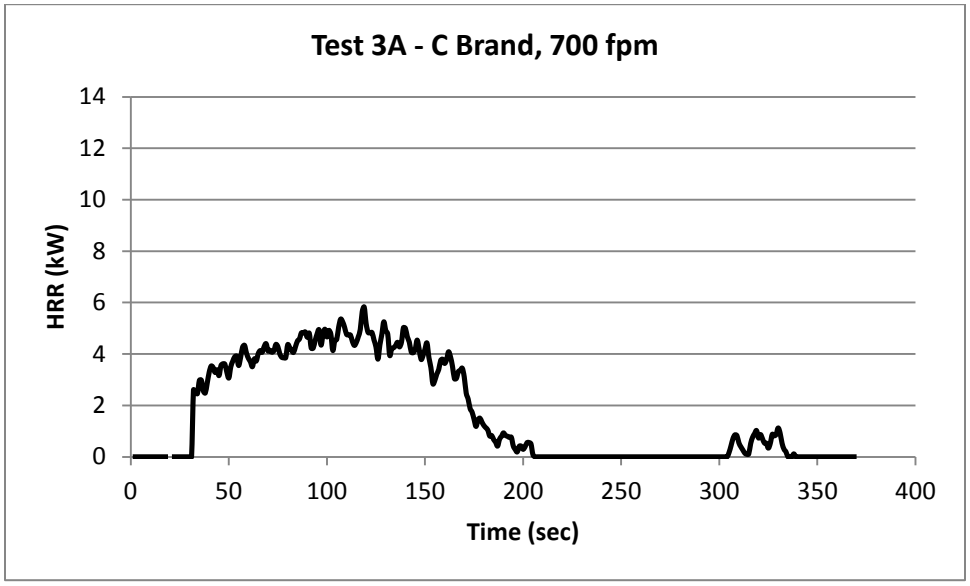

Figure 35 - Graph of Heat Release Rate (HRR) in kilowatts

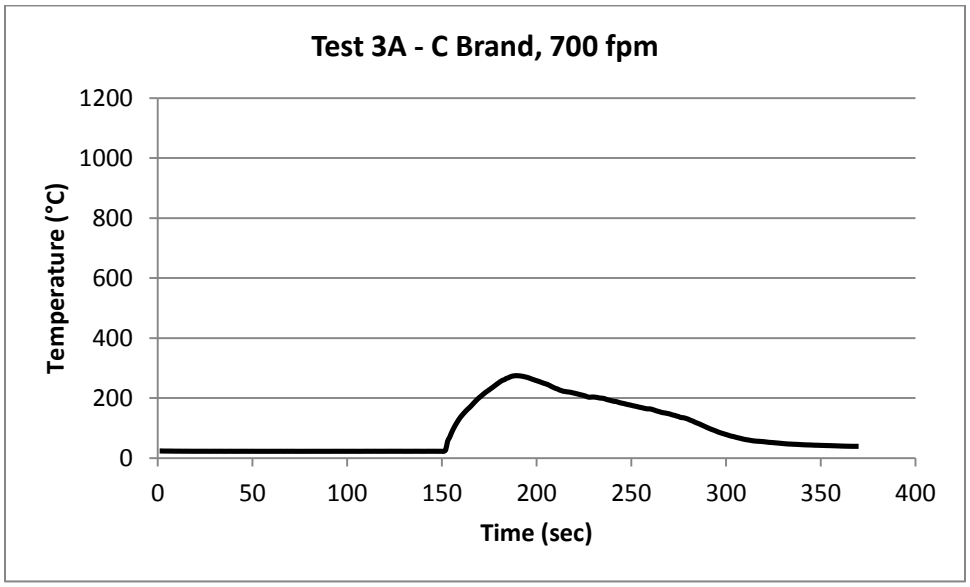

Figure 36 - Graph of Deck Surface Temperature (°C)

Test 3B - Sample=C Brand - Instrumented Roof Deck - 700 fpm

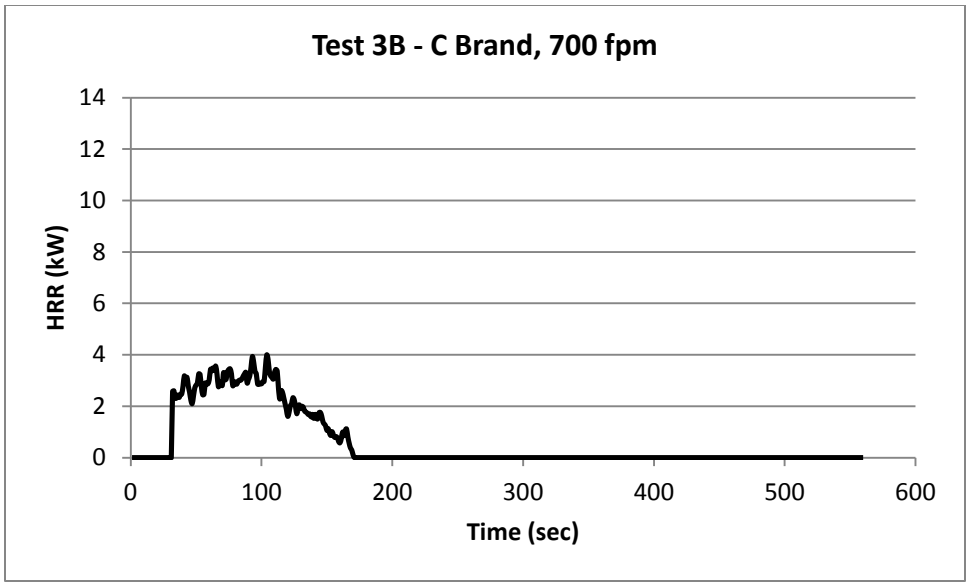

Figure 37 - Graph of Heat Release Rate (HRR) in kilowatts

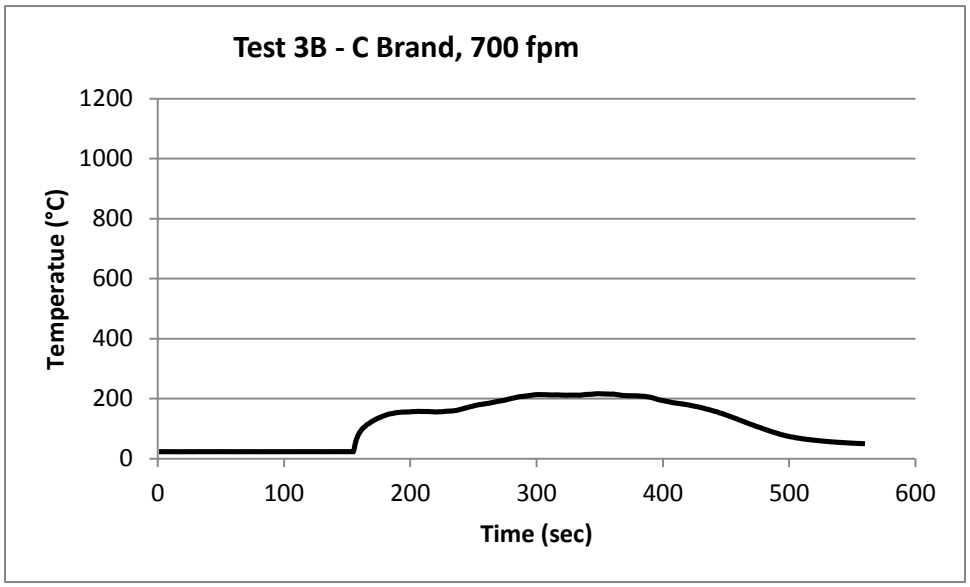

Figure 38 - Graph of Deck Surface Temperature (°C)

Test 3C - Sample=C Brand - Instrumented Roof Deck - 700 fpm

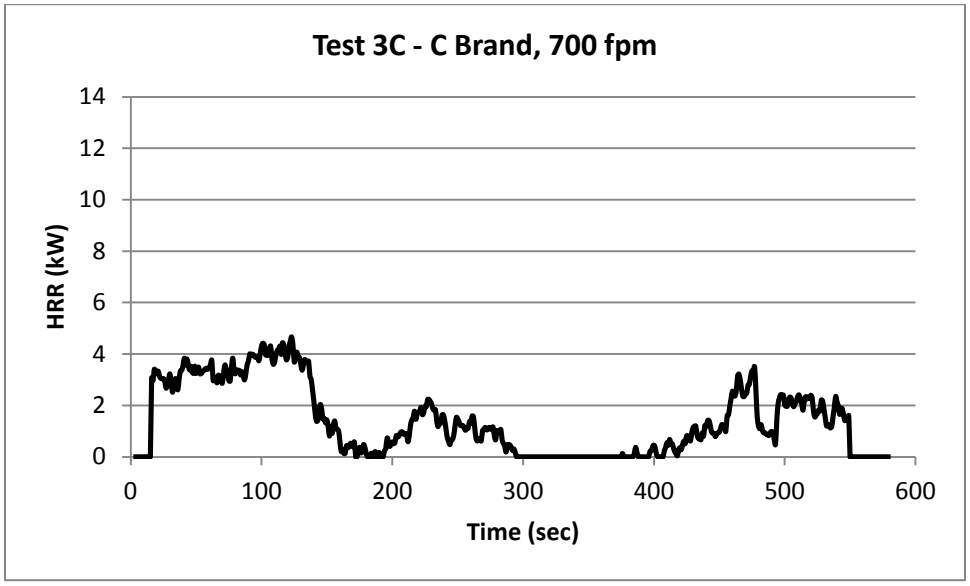

Figure 39 - Graph of Heat Release Rate (HRR) in kilowatts

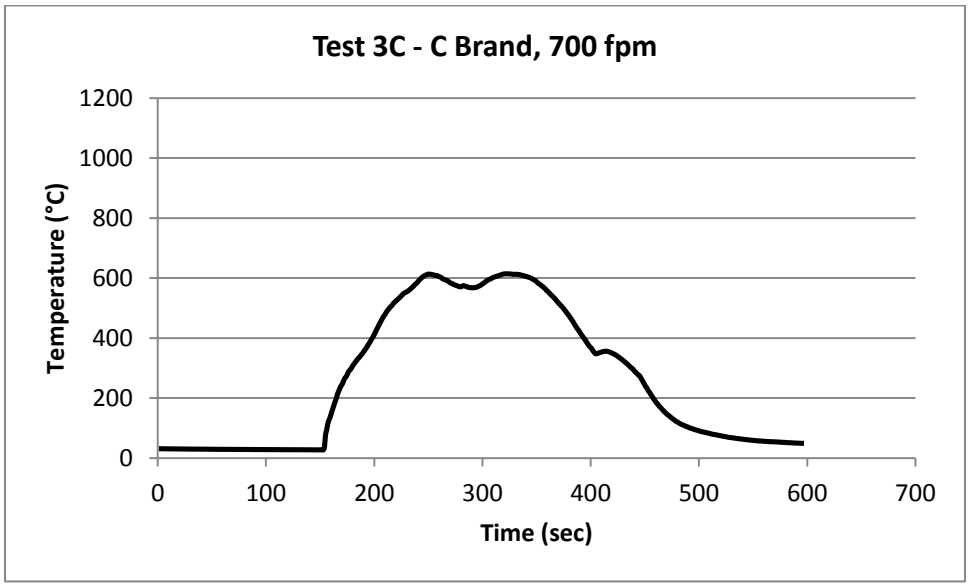

Figure 40 - Graph of Deck Surface Temperature (°C)

Test 4 - Sample=Excelsior Wood Wool - Instrumented Roof Deck - 0 fpm

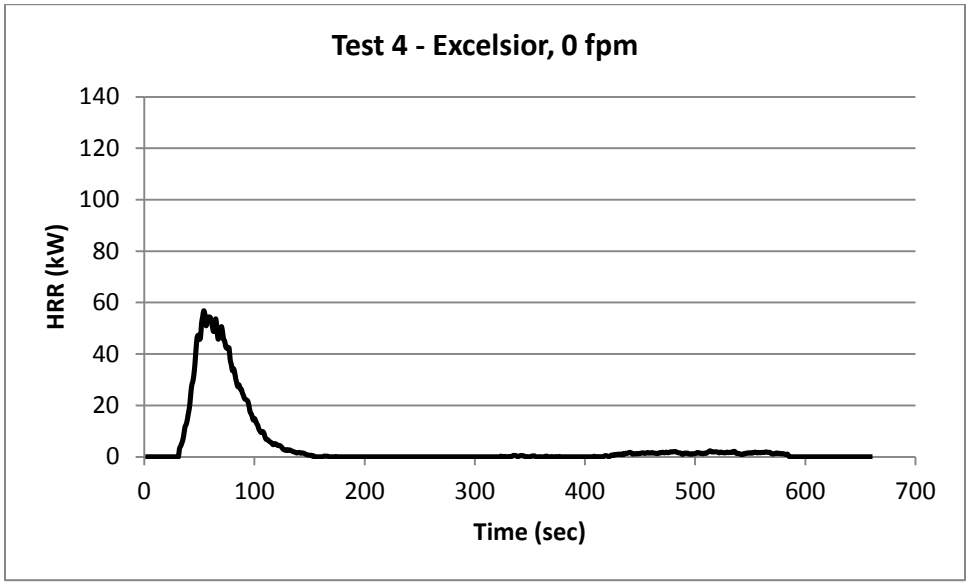

Figure 41 - Graph of Heat Release Rate (HRR) in kilowatts

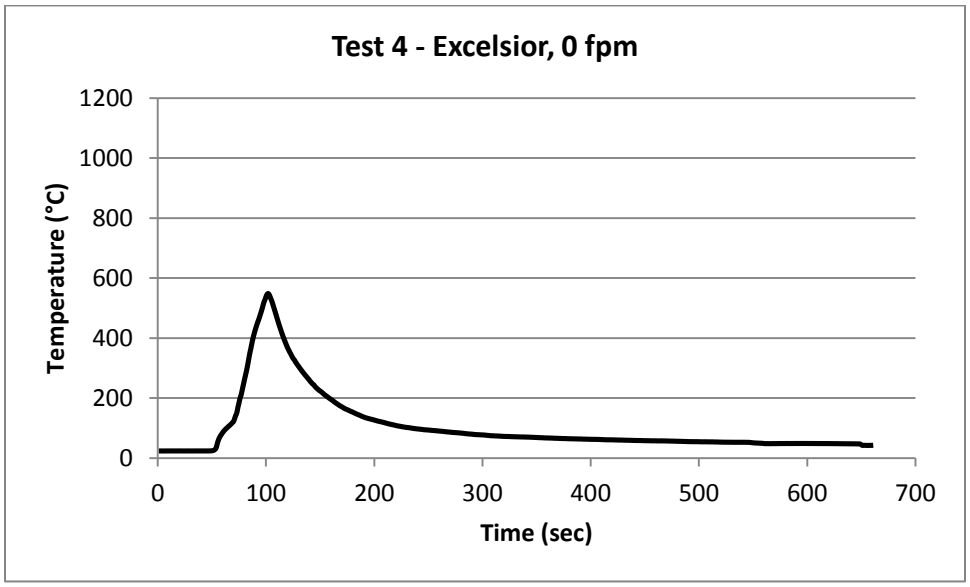

Figure 42 - Graph of Deck Surface Temperature (°C)

Test 5 - Sample=Leaves - Instrumented Roof Deck - 0 fpm

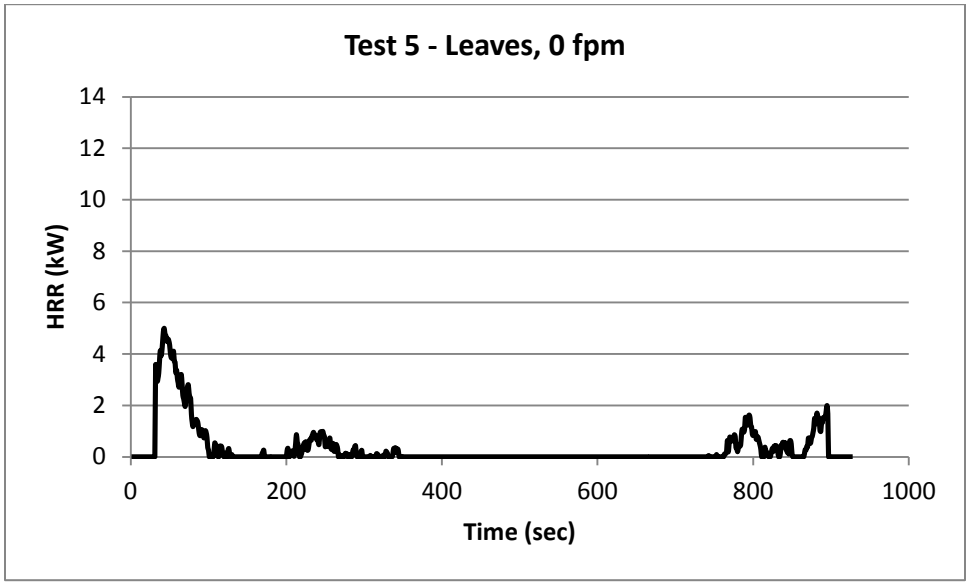

Figure 43 - Graph of Heat Release Rate (HRR) in kilowatts

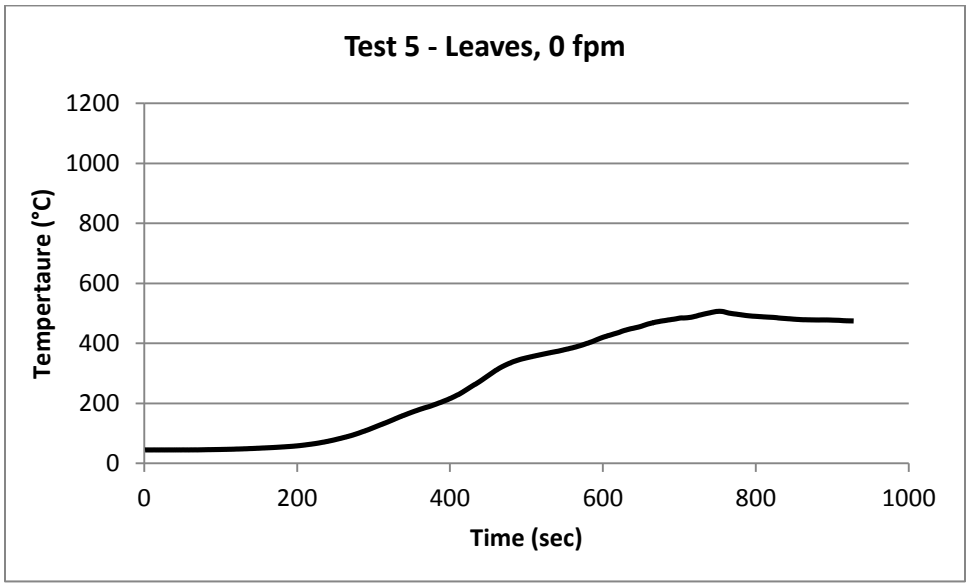

Figure 44 - Graph of Deck Surface Temperature (°C)

Test 6 - Sample=Excelsior Fluffed - Instrumented Roof Deck - 0 fpm

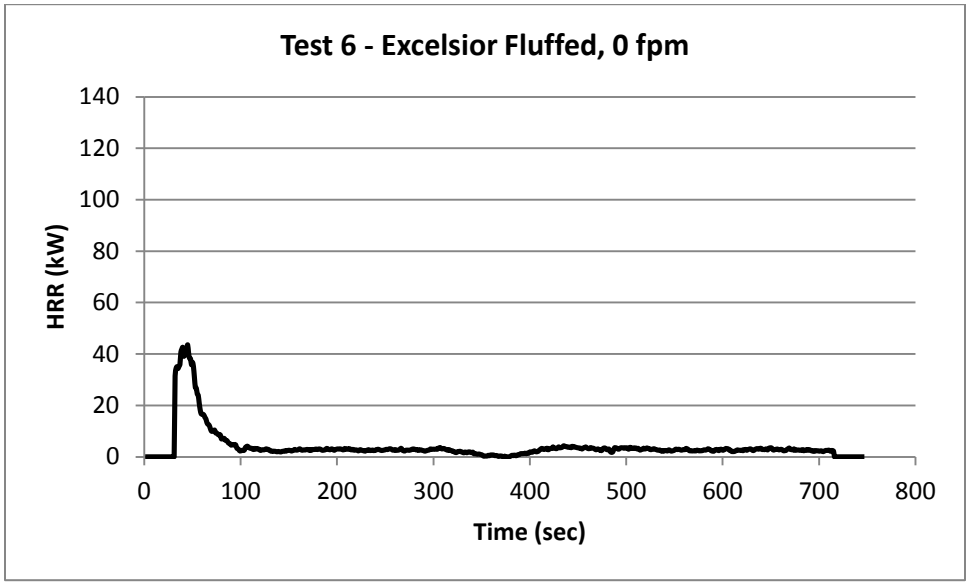

Figure 45 - Graph of Heat Release Rate (HRR) in kilowatts

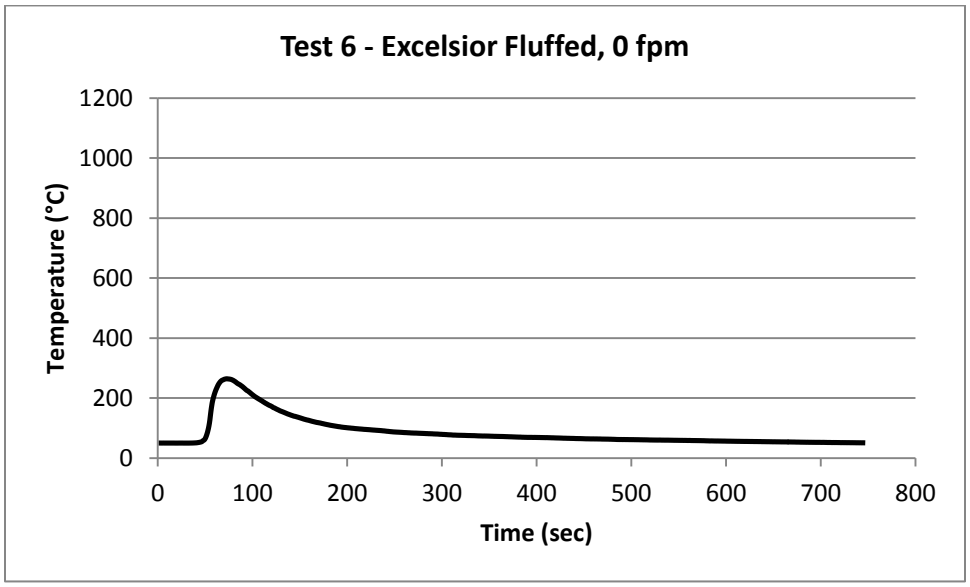

Figure 46 - Graph of Deck Surface Temperature (°C)

Test 7 - Sample=Excelsior Compressed - Instrumented Roof Deck - 0 fpm

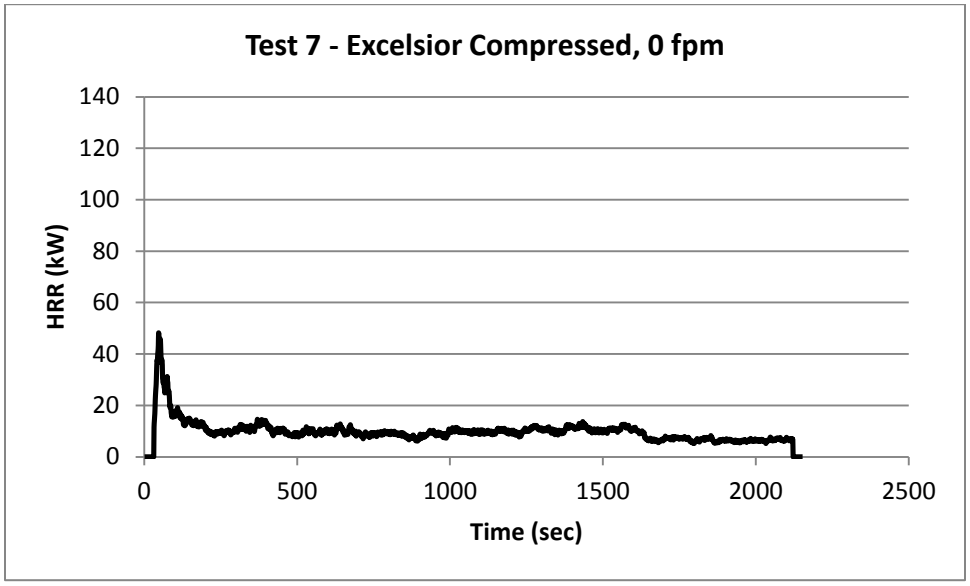

Figure 47 - Graph of Heat Release Rate (HRR) in kilowatts

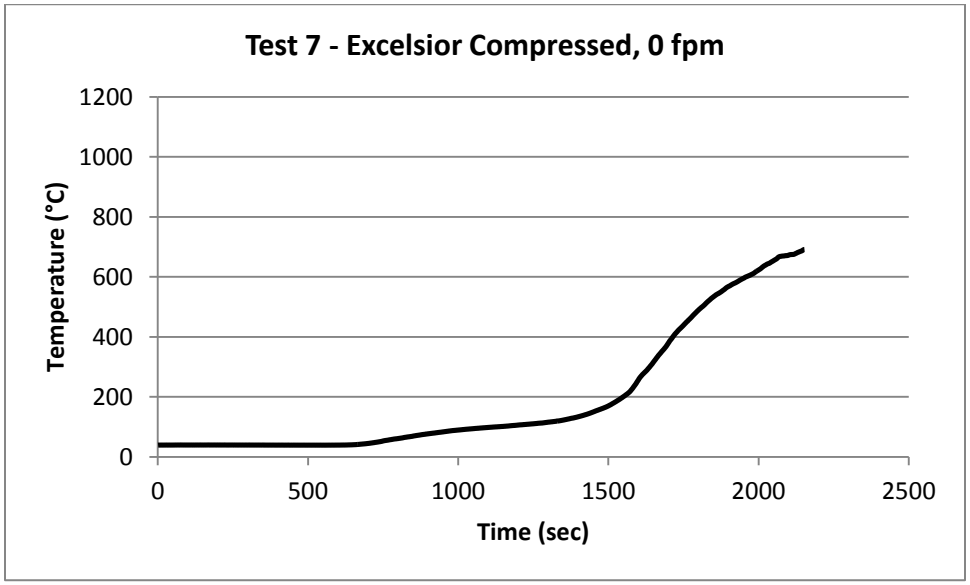

Figure 48 - Graph of Deck Surface Temperature (°C)

Test 8 - Sample=Leaves - Instrumented Roof Deck - 350 fpm

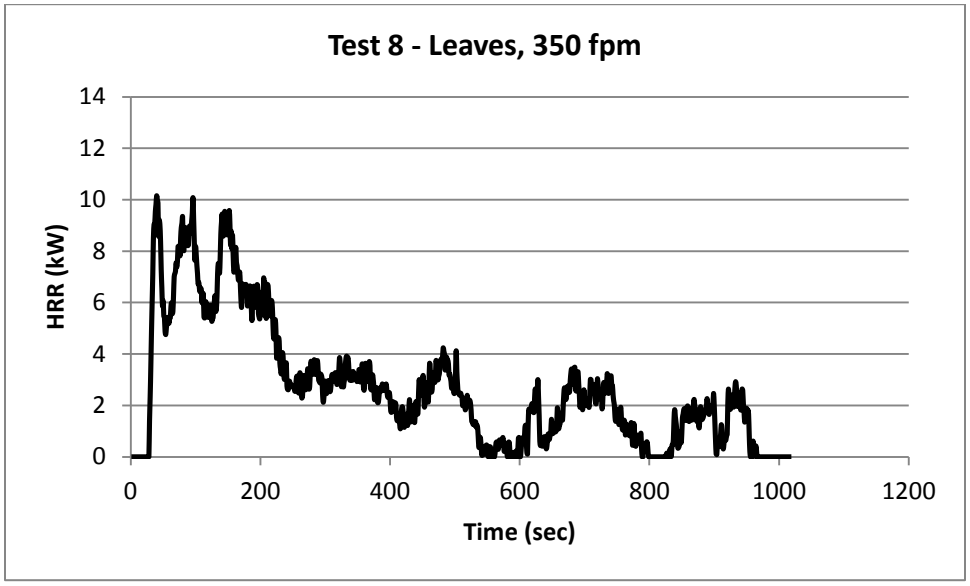

Figure 49 - Graph of Heat Release Rate (HRR) in kilowatts

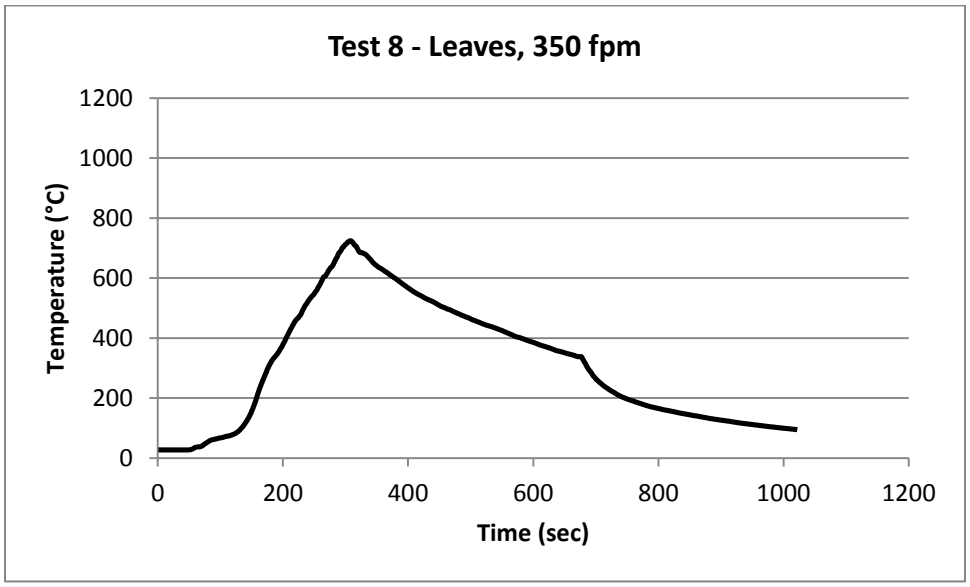

Figure 50 - Graph of Deck Surface Temperature (°C)

Test 9 - Sample=Excelsior Compressed - Instrumented Roof Deck - 350 fpm

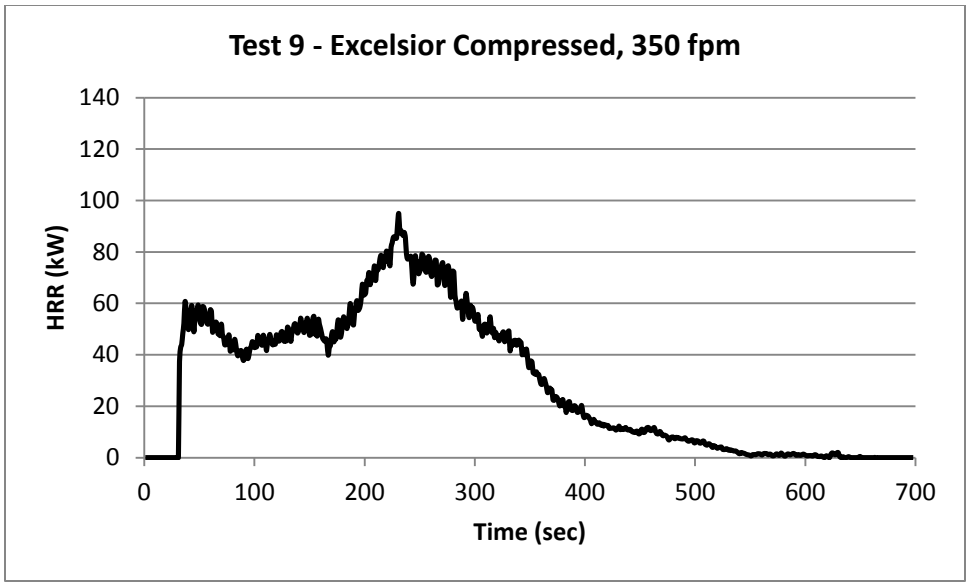

Figure 51 - Graph of Heat Release Rate (HRR) in kilowatts

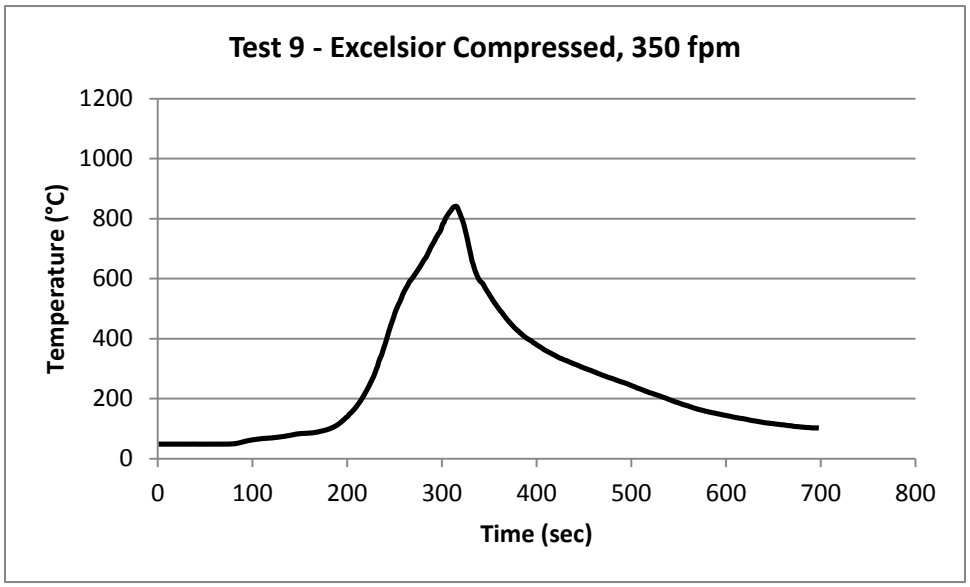

Figure 52 - Graph of Deck Surface Temperature (°C)

Test 10 - Sample=Excelsior Fluffed - Instrumented Roof Deck - 350 fpm

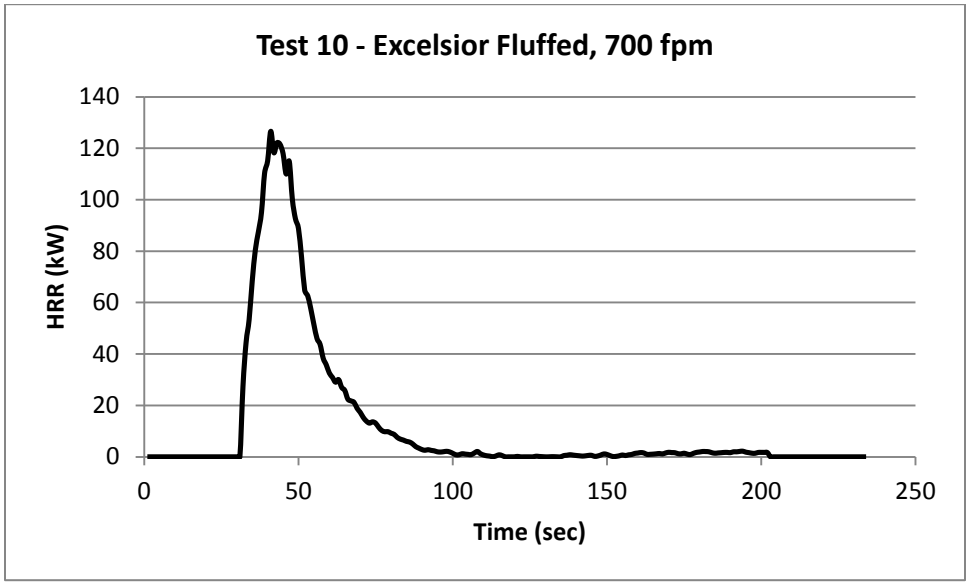

Figure 53 - Graph of Heat Release Rate (HRR) in kilowatts

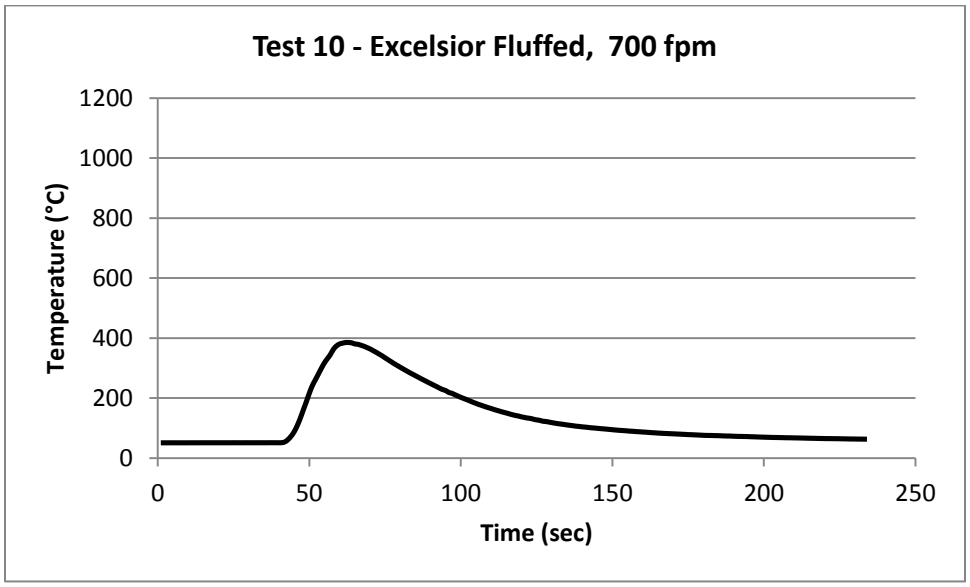

Figure 54 - Graph of Deck Surface Temperature (°C)

Test 11 - Sample=A Brand - Instrumented Shingled Roof Deck - 700 fpm

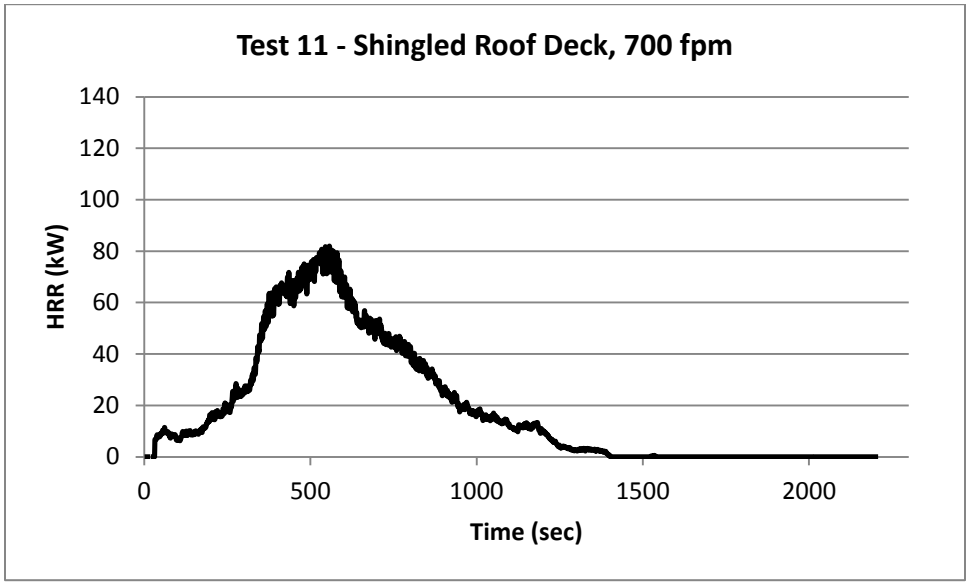

Figure 55 - Graph of Heat Release Rate (HRR) in kilowatts

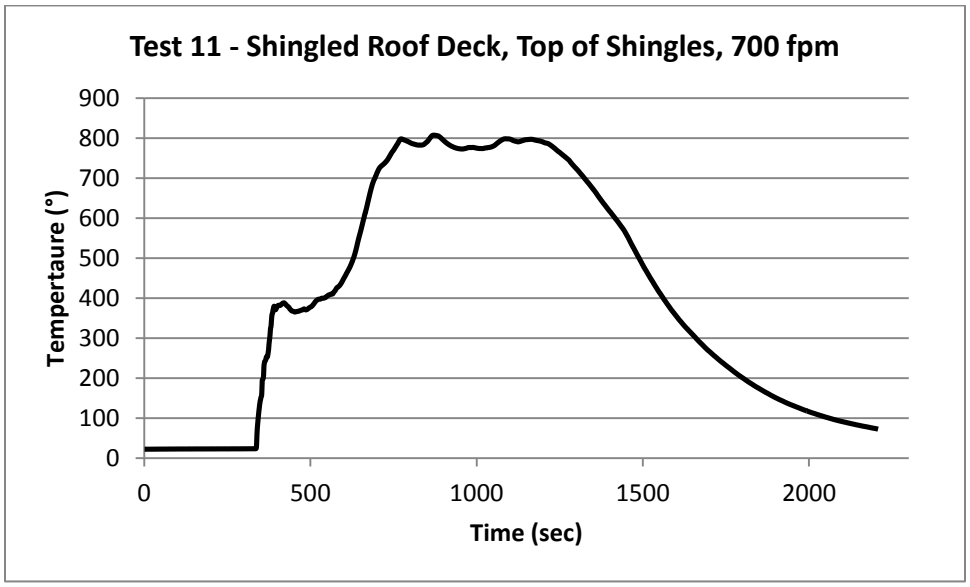

Figure 56 - Graph of Shingle Surface Temperature (°C)

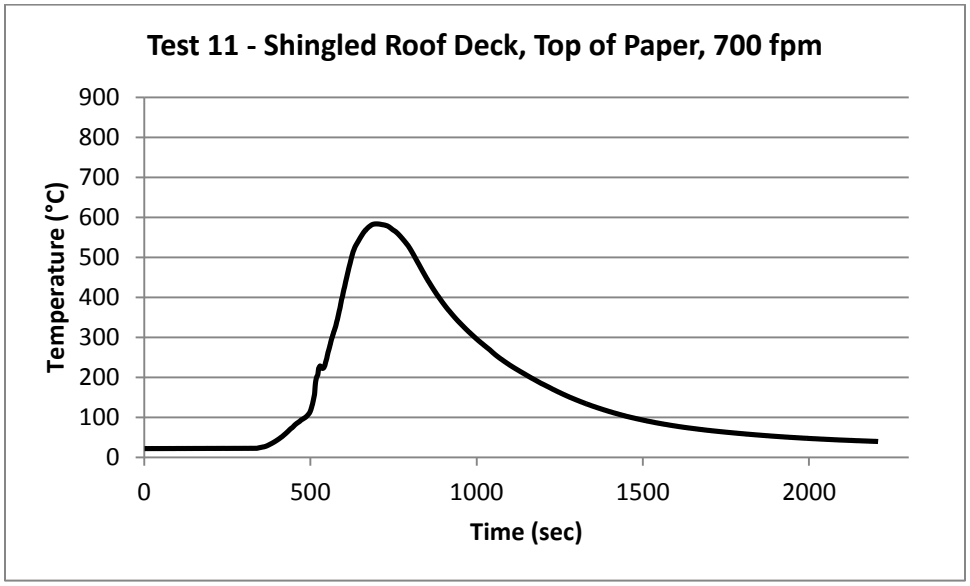

Figure 57 - Graph of Tar Paper Surface Temperature (°C)

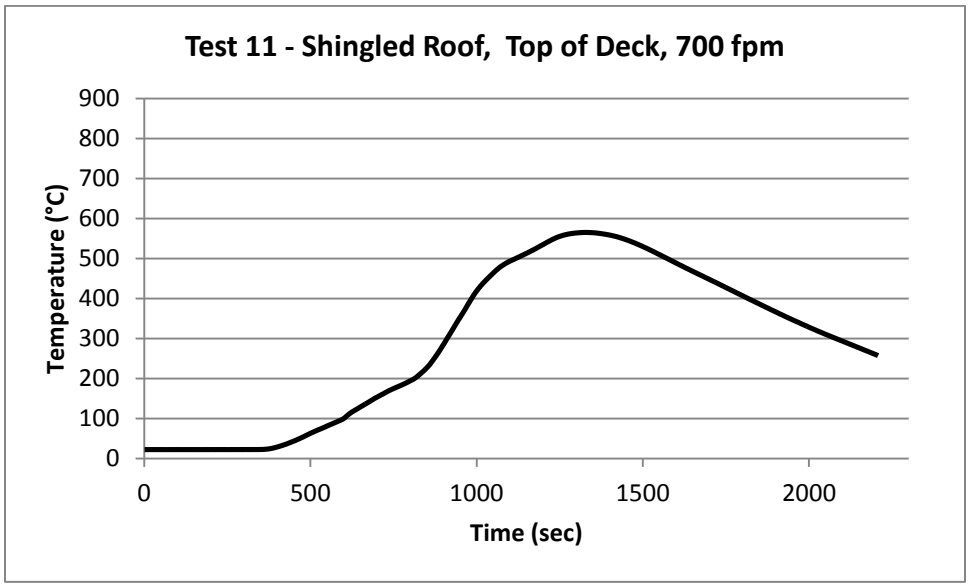

Figure 58 - Graph of Deck Surface Temperature (°C)

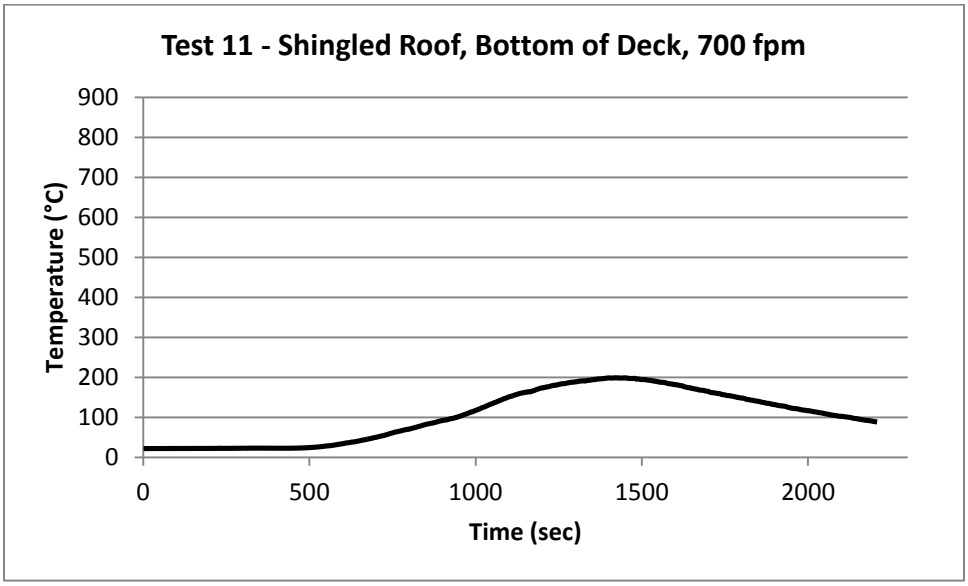

Figure 59 - Graph of Underside of Deck Surface Temperature (°C)

Task 2 - Summary

The following is a summary of the results:

- Under similar wind conditions of 700 fpm, the Class A brand developed a significantly greater amount of energy than the Class C brand both in peak and total.

- The leaf debris and excelsior generated substantially less energy than the Class A brand, but significantly greater than an individual Class C brand. One significant challenge with the use of leaf debris or excelsior is an expected variation of energy generated due to the nature of the material.

- As expected, air flow increased the peak energy generated, as illustrated by the Class A brand experiments under an airflow of 700 fpm and 0 fpm.

Overall, the heat release rate and heat transfer to the roof surface of Class A and Class C brands did not demonstrate a direct correlation to common materials that may collect between PV modules and the roof surface, such as leaf debris and excelsior (wood wool). The Class A brand yielded results significantly greater than the leaf debris and wood excelsior while the Class B brand yielded results significantly less than the leaf debris and wood excelsior. While the Class B brand was not included in the experiments, the deduction of these experiments is that the representation of common materials is closest to the Class B brand in terms of heat release and heat transfer to the roof surface.

The data generated provides a base understanding of the burning characteristics of the standard brands, wood excelsior and leaf debris. Where peak heat release rate indicates a magnitude, the total heat release provides some relative data for comparison of duration of burning items. While heat release rate is an important quantification of a fire, it does not by itself describe the complete thermal stress imposed by a burning object onto a roof.

SUMMARY AND RECOMMENDATIONS

SUMMARY OF FINDINGS

An analysis of the data generated by the experiments carried out in this study point to the following key findings:

- Some PV modules mounted at angles (positive and negative) to steep and low sloped roofs impacted the fire classification rating of the supporting roof assembly. The extent of the impact was dependent on the angle of the module relative to the roof and the type of roofing system,

- PV modules mounted at zero clearance to the roof surface demonstrated no impact to the fire rating of the roof when the ignition source flame was directed to the front vertical surface of the module or when the ignition source flame was directed along the horizontal face of the module,

- The heat release rate and heat transfer to the roof surface of Class A and Class C brands did not demonstrate a direct correlation to common materials that may collect between PV modules and the roof surface, such as leaf debris and excelsior (wood wool). The Class A brand yielded results significantly greater than the leaf debris and wood excelsior while the Class B brand yielded results significantly less than the leaf debris and wood excelsior. While the Class B brand was not included in the experiments, the deduction of these experiments is that the representation of common materials is closest to the Class B brand in terms of heat release and heat transfer to the roof surface.

RECOMMENDATIONS

Based on the research conducted in this study, the Research Team would like to make the following recommendations:

- Consider additional installation parameters including low slope insulation thickness and formulations such as polystyrene and initial elevations. This will provide a more complete understanding of PV / roof assembly fire classification performance,

- Continue research in this area to evaluate the sensitivity of the fire performance of roofing systems to the various PV installation methodologies. As a matter of practicality, it is unlikely that a manufacturer would submit every possible PV and roofing product installation configuration to a standard fire test. Further work is needed to determine a generic roofing material which can be specified as a worst case for testing of PV modules,

- This research should be shared with the external fire community and key stakeholders and internally through the UL 790 and UL 1703 Standards Technical Process (STP),

- The Standards Technical Panel should specifically consider the findings in this Report on the burning behaviors of burning brands and the common materials that may collect between PV modules, as they propose revisions to test methods and performance criteria for the burning brand requirements in UL 1703,

- If additional research is undertaken, continued input from a broad fire safety community including firefighters, fire marshals, and authorities having jurisdiction (AHJ) should be solicited in addition to industry representatives such as PV manufacturers and associated equipment manufacturers.

Effect of Rack Mounted Photovoltaic Modules on the Fire Classification Rating of Roofing Assemblies

Project Number: 08CA39594, 09CA40917
File Number: IN15911, R26475
Date: September 30, 2009
Revised February 4, 2010
Revised March 5, 2010
Revised November 30, 2010

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ACKNOWLEDGMENTS

The authors would like to acknowledge the following individuals for their contributions including guidance and support for this project:

Bill Brooks of Brooks Engineering
Larry Sherwood of Sherwood Associates
Kevin Lynn of the Department of Energy (DOE)
Andy Rosenthal of New Mexico State University

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EXECUTIVE SUMMARY

As a result of the increased use of PV in homes and commercial buildings, in combination with efforts to mitigate the effects of fires, fire officials are interested in understanding the effect that a rack mounted PV system has on a Class A roof To date, there are few Class A rated PV modules or building-integrated photovoltaic (BIPV) products from all the several hundred listed modules. At present, the effect of fire on UL 790 fire Class A rated roofing materials when Class C rated PV modules are installed is not well understood. For instance will a Class C rated module reduce the fire resistance performance and/or fire rating of some Class A rated roof systems? If so, which roof systems are impacted and to what extent?

NEW FIRE SAFETY RESEARCH PROJECT

A review of the National Fire Incident Reporting System (NFIRS)[1] statistics offers minimal insights into fire hazards associated with photovoltaic (PV) modules installed on roofs. While NFIRS data does not provide detailed information on PV modules as a cause or fire hazard contributing to home structural fires, the impact of these modules on the fire rating of roofing assemblies has been a concern to the California State Fire Marshals[2]. In response to these concerns, UL in partnership with Solar America Board for Codes and Standards (Solar ABCs) contracted with New Mexico State University to design and conduct a research project with funding from the Department of Energy (DOE) under award number DE-FC36-07GO17034.

This research project was undertaken to generate critically needed test data to help speak to pertinent fire safety questions and issues associated with the use of a rack mounted PV modules over Fire Class rated roofing materials. A cross-functional team, consisting of members from UL's Corporate Research, Primary Designated Engineers, and Conformity Assessment Services organizations was established to develop and execute the project. The research project was consisted of 2 phases.

During Phase 1, the objective was to study the influence of a rack mounted PV module on a roof deck under exposure from standard fire tests such as UL 790[3]. These tests utilized a PV surrogate constructed of non-combustible materials over a non-combustible roof deck to isolate the effect of the installation of a module on a roof[4]. All assemblies were instrumented with thermocouples and heat flux gauges to obtain temperature and heat flux data at different points along the roof and PV. In addition, limited burning brand tests and spread of flame tests were conducted using actual PV modules to demonstrate the current state. These tests were conducted to measure the effects of multiple installation configurations including:

---

[1] www.nfirs.fema.gov

[2] osfm.fire.ca.gov/training/photovoltaics.php

[3] UL 790, Standard Test Methods for Fire Tests of Roof Coverings, 8th Edition, Underwriters Laboratories Inc., 2004.

[4] For all tests conducted in this study, the rack mounted PV module was parallel to the surface of the roof.

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- *Establish baseline data of fire exposure on roof deck samples without PV according to UL 790*
- *The effect of PV module stand-off height above the roof and leading edge distance*
- *Orientation of the PV module mounting rails on the roof surface*

Based on the results of the Phase 1, test parameters were identified for Phase 2. In this phase, tests were performed on PV modules with combinations of different roofing materials. The key objectives of the Phase 2 were as follows:

- *Develop baseline data on the fire exposure during standard tests for roof with no PV module according to UL 790*
- *Determine the effect of varying selected PV installation parameters*
- *Document the impact of lesser fire rated PV modules on common roofing assemblies*

SUMMARY OF FINDINGS

Based on the findings in this report, the installation of a rack mounted PV module on a roof has an impact on the fire resistance ratings of the roof system, regardless of the fire rating of the roof or PV module. For instance, the increase in distance (setback) between the leading edge of the roof and the PV module lessens the chances that the flame will be captured in the gap between the PV panel and roof surface that might otherwise lead to significant burning during the spread of flame test.

INFLUENCE OF A RACK MOUNTED PV MODULE ON ROOF

Results from Phase 1 of this investigation showed that for a surrogate rack mounted PV module parallel to the roof surface, the fire exposure from the Spread of Flame test resulted in greater temperatures on the roof surface in the area underneath the PV module. In addition, the heat flux on the roof surface also increased. The magnitude of these effects was dependent on the gap size between the module and the roof, as well as the setback distance of the module from the roof leading edge.

For the parameters in this study, it was found that when the gap between the rack mounted PV module and the roof was reduced from 10 inches to 5 inches the measured surface temperatures increased[5]. It was observed that both the 10 inch and 5 inch gap captured all of the flames, however the smaller gap also reduced the amount of entrained air into the fire plume thus elevating the temperature of exposed surfaces. When the gap size was reduced further to the value of 2.5 inch, the measured surface temperatures did not increase but rather lowered, as the gap was sufficiently decreased to capture only a portion of the flames.

[5] This does not suggest that a 5-inch gap leads to worst case as compared to all values of gap size but only for those gap size increments selected in the tests described in this report.

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The influence of the setback of the PV module on the measured temperature and heat flux on the roof surface was highest when the PV module was in line with the leading edge (i.e., no setback distance). The measured temperatures and heat flux exposure lessened as the setback distance was extended.

INTERACTION BETWEEN PV MODULE AND FIRE RATED ROOF SYSTEM

Results from Phase 1 study showed that installation of PV modules on roofs had an adverse affect on the Fire Class Rating of the roof assembly. For further confirmation, more experiments were conducted in Phase 2 with the PV module placed at the roof leading edge (0 in. setback distance) with a 5 in. gap between the PV module and roof surface. The results from PV modules on fire rated roof systems for the Spread of Flame tests are listed in Table E1. These results suggest that the presence of a PV module adversely affects the fire rating of a roof. If a roof is noncombustible, the flame spreads through the gap between the roof and the PV module in excess of 8 ft.

Table E1 – Influence of PV Module During Spread of Flame Test

Roof Rating	PV Rating	Flame Spread
A	C	Greater than 8 ft.
A	A	Greater than 8 ft.
C	C	Greater than 8 ft.
Noncombustible	C	Greater than 8 ft.
Noncombustible	A	Greater than 8 ft.

Some results of PV modules on fire rated roof systems for the Burning Brand Tests are described in Table E2. In the brand test involving Class A rated roof and Class C rated PV panel with the brand located on the roof, it was observed that the PV panel sagged and collapsed onto the roof allowing flames to vent vertically. This prevented the flame from penetrating the roof. However, though the results from two tests did meet the requirements for Class A, a third test did not. Since there was one case where the results were not in compliance with Class A requirements, clearly the random nature of fire growth and spread of the PV module affects the outcome of these particular tests.

Table E2 - Brand Test

Roof Rating	PV Rating	Brand Size / Position	Fire Performance Result
A	C	Class A / PV	Compliant
A	C	Class A / Roof	2 Compliant/ 1 not compliant
C	C	Class C / Roof	Not compliant
A	A	Class A / Roof	Not compliant

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For the test involving a Class A rated roof with a Class A rated PV with the brand located on the roof, the results were not compliant. The Class A module increased the thermal load on the roof.

For the case of a Class A rated roof and a Class C rated PV with the brand located on the PV module, the results of the test meet Class A requirements as the module simply provides an additional barrier between the brand and the roof for some period of time.

For the Burning Brand tests for the Class C roof with Class C PV module with the brand located on the roof, where the results were not compliant with the requirements, the PV panel remained intact, thereby trapping the heat between the panel and the roof. This led to a breach of the fire through the roof surface and the observed non-compliance.

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TABLE OF CONTENTS

DISCLAIMER 3

ACKNOWLEDGMENTS 4

EXECUTIVE SUMMARY 5

NEW FIRE SAFETY RESEARCH PROJECT 5
SUMMARY OF FINDINGS 6
Influence of a Rack Mounted PV module on Roof 6
Interaction between PV module and Fire Rated Roof System 7

PROJECT BACKGROUND 11

NEED FOR RESEARCH 11
FIRE CLASSIFICATION RATINGS OF ROOFING MATERIALS 12
Spread of Flame Test 13
Intermittent Flame Test 13
Burning Brand Test 14
FIRE CLASSIFICATION RATINGS OF PV MODULES 15

RESEARCH INVESTIGATION 17

RESEARCH OBJECTIVES 17
TECHNICAL PLAN 18
PHASE 1/ TASK 1 – SELECT AND ACQUIRE TEST SAMPLES 19
Roofing Materials 19
Photovoltaic Modules 19
PHASE 1/TASK 2 – EXPERIMENTS WITH NONCOMBUSTIBLE ROOF AND PV MODULE 20
Test Matrix 20
Test Set-Up 21
Instrumentation 21
TEST PROCEDURE 23
Results 23
Analysis of Data 26
PHASE 1/TASK 3 LIMITED EXPERIMENTS WITH COMBUSTIBLE ROOFS AND PV 35
Objective 35
Experimental Parameters 35
Results 35
Analysis 44
PHASE 2/TASK 4 - EXPERIMENTS WITH VARIOUS FIRE-RATED ROOF ASSEMBLIES/PV MODULE COMBINATIONS 44

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Objective 44
Experimental Parameters 44
Results 44
Analysis 54
SUMMARY OF FINDINGS 55

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PROJECT BACKGROUND

This research project was supported by the Department of Energy (DOE) under award number DE-FC36-07GO17034. The lead for this project was New Mexico State University, Las Cruces, NM. UL was a subcontracted partner under this initiative.

NEED FOR RESEARCH

The growth of solar Photovoltaic (PV) has been substantial in the last few years (Figure 1) especially in California with 58% of all grid-tied PV capacity in the US in 2007. As a consequence of the prevalence of solar PV modules on roofs and plans for additional deployment, fire safety officials are concerned about the potential fire risks when a rack mounted PV array is installed on a rooftop. However, insufficient data exists on the precise nature of the risk and possible remedies. As California State Fire Officials are preparing to implement a statewide requirement for Class A fire rating of all roofing products including PV panels, the need for comprehensive data to help guide discussions and decisions is even more pressing.

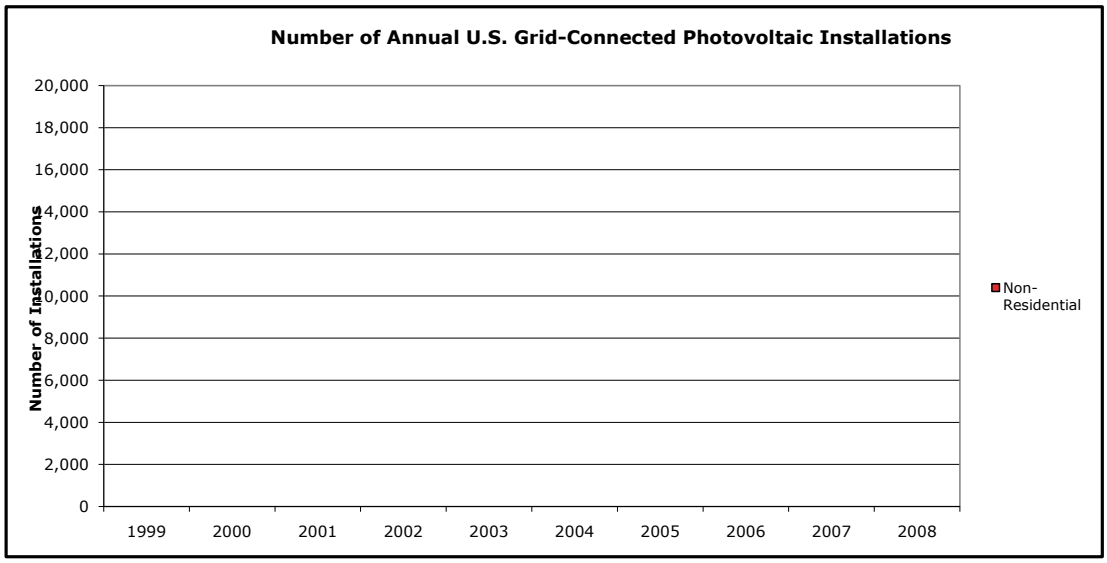

Figure 1 – Increase in Photovoltaic Module Deployment[6]

Though the electric and fire hazards associated with PV arrays have been known for some time[7], most of the research on the fire risks of PV modules has focused on the PV as a fire source due to internal shorting or arcing. Some research in this area has focused on heat

[6] Source: U.S. Solar Market Trends 2008, Interstate Renewable Energy Council, 2009

[7] P.D. Moskowitz, et al., Rooftop Photovoltaic Arrays: Electric Shock and Fire Health Hazards, Solar Cells, 1983, pp. 327-336.

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transfer aspects of PV[8] and some limited fire performance[9], however, only a single research paper was found that quantified the effect on flame spread of a rack mounted solar collectors on a roof deck. The researchers[10] at the National Bureau of Standards (now National Institute of Standards and Technology) tested roofs with different types of solar collector module mountings as shown in Figure 2. For the spread of flame tests, the results were primarily for a Class C test conditions.

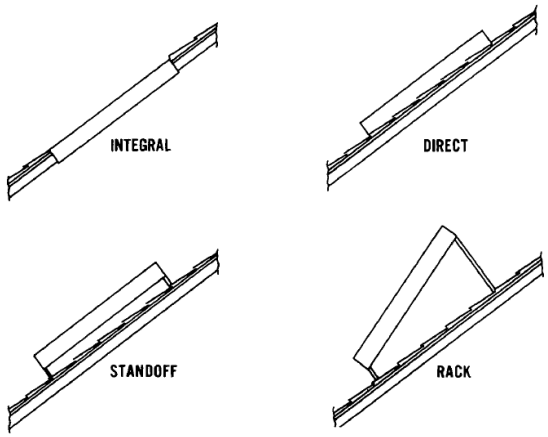

Figure 2 – Collector mounting configurations described in paper by Waksman[10].

The authors observe that 'the presence of any type of collector case material (either combustible or noncombustible) directly above the roof covering appears to increase or enhance radiative heat transfer to the roof …'. However, they conclude that 'it is not known whether or not this [*increase in flame spread*] will result in a substantial increase in hazard in reducing the fire integrity of the roof deck itself.'

FIRE CLASSIFICATION RATINGS OF ROOFING MATERIALS

Roofing materials are evaluated for classification of fire ratings by tests conducted in accordance with UL 790: Tests for Fire Resistance of Roof Covering Materials. They are rank ordered in fire performance hierarchy of Class A, Class B or Class C.

- *Class A assemblies are considered to be effective against severe fire test exposures*
- *Class B assemblies are considered to be effective against moderate fire test exposures*
- *Class C assemblies are considered to be effective against light fire test exposures*

[8] Z. Zhu, et al., Numerical Analysis of Heat Transfer in A Photovoltaic Module, I:Indoor Cases, International Communication of Heat and Mass Transfer, Vol. 29, No. 4, 2002, pp. 497-508.
[9] T. Ohuchi et al., Improvement of the Fire-Proofing and Fire-Resistance Properties of PV Modules for Building's Exterior Walls, IEEE, 2000, pp. 1533-1538.
[10] D. Waksman, et al., Fire testing of solar collectors by ASTM E 108, Fire Technology, Vol. 18, No. 2, 1982.

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The fire performance ratings are determined from the results of three different fire tests described in UL 790: (i) Spread of flame test, (ii) Intermittent flame test and, and (iii) Burning brand test. In this research, the focus will be on Spread of Flame and Burning brand tests since these are the required fire tests in UL 1703.

SPREAD OF FLAME TEST

The Spread of Flame Test measures the potential for flame spread across the surface of the roof assembly using a constant flame source. The setup for the test is shown in Figure 3.

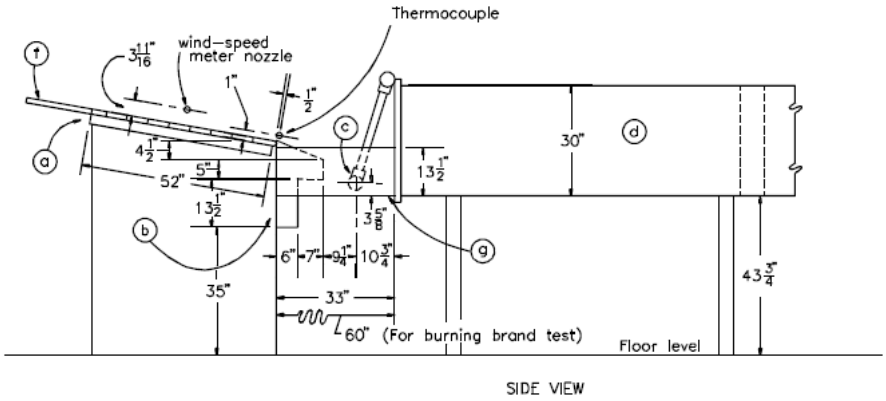

Figure 3 Test setup for UL 790

The flame source is approximately triangular in shape, measuring 3 feet (0.9 m) wide at the leading edge of the deck. The gas supply is regulated so that the flame is within the range from 21,000 to 22,000 Btu per minute (369 to 387 kWh) for Class A and 18,000 to 19,000 Btu per minute (316 to 334 kWh) for Class C samples. For a Class A test, the gas flame is to be applied continuously for 10 minutes or until the spread of flame (flaming of the material being tested) permanently recedes from a point of maximum spread, whichever is the shorter duration. For a Class C test, the gas flame is to be applied for 4 minutes and then removed.

Class A is achieved if the maximum flame spread does not exceed 6 feet. Class B is achieved if the maximum flame spread does not exceed 8 feet. Class C is achieved if the maximum flame spread does not exceed 13 feet. For all classifications, the fire cannot spread laterally to both edges of the test deck, burning or glowing particles cannot fall to the floor and continue to burn or glow, and a combustible roof deck cannot be exposed (visible) at the conclusion of the test. For all classifications, air is introduced over the surface of the test sample at a velocity of 12 mph. For Class A & B, the test duration is 10 minutes. For Class C, it is a 4-minute test.

INTERMITTENT FLAME TEST

The Intermittent Flame Test measures the potential for fire to penetrate from the outside of the roofing assembly to the underside (inside the building) of the combustible roof deck using

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a variable flame source. The flame temperature and wind speed are identical to those listed in the Spread of Flame Test. Successful results are achieved provided there is no sustained flaming (a continuous burning flame) of the underside of the test deck and burning or glowing particles do not fall to the floor and continue to burn or glow. It should be noted that the intermittent flame test is not required in the standard for PV modules, UL 1703 Flat-Plate Photovoltaic Modules and Panels and was not part of this research project.

Test conditions are shown in the following in Table 1.

Table 1

	Ignition On (min)	Sequence Off (min)	Number of Cycles	Duration After Last Cycle (min)
Classification				
A	2	2	15	60
B	2	2	8	60
C	1	2	3	30

BURNING BRAND TEST

The Burning Brand test measures the potential for fire to penetrate from the outside of the roofing assembly to the underside (inside the building) of the combustible roof deck using a burning brand fire source. The brands (Figure 4) are positioned on the top surface of roof assembly at locations as described in the standard. Successful results are achieved provided there is no sustained flaming (a continuous burning flame) of the underside of the test deck and burning or glowing particles do not fall to the floor and continue to burn or glow.

Brand A Brand B Brand C

Figure 4 – UL 790 - Burning Brands

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FIRE CLASSIFICATION RATINGS OF PV MODULES

PV modules are evaluated for fire classification rating by tests conducted in accordance with UL 1703 Flat-Plate Photovoltaic Modules and Panels[11]. The standard uses the Spread of Flame Test and the Burning Brand Test described in UL 790. In the test, the PV module is placed directly on the roof deck. The Burning Brand test is conducted with the brand(s) placed on top surface of the PV module. The PV modules are rank ordered in a performance in a hierarchy of Class A, Class B or Class C consistent with roofing products.

The performance criteria in UL 1703 for the spread of flame test are as follows:

"At no time during or after the tests shall:

a) Any portion of the module or module be blown off or fall off the test deck in the form of flaming or glowing brands;

b) Portions of the roof deck, or portions of a module or module intended for installation integral with or forming a part of the building roof structure, fall away in the form of glowing particles;

c) The flame spread beyond 6 ft (1.82 m) for Class A, 8 ft (2.4 m) for Class B, or 13 ft (3.9 m) for Class C rating. The flame spread is to be measured from the leading edge of the sample; or

d) There be significant lateral spread-of-flame from the path directly exposed to the test flame. Spread-of-flame includes flaming on both the top surface (the surface to which the external flame is applied) and in any intermediate channel, such as the space between stand-off or integral modules and a shingle roof."

The performance criteria in UL 1703 for the burning brand test are as follows:

"At no time during or after the tests shall:

a) Any portion of the module or module or be blown off or fall off the test deck in the form of flaming or glowing brands;

b) The brand burns a hole through the roof covering or through any part of the module or module;

c) Portions of a module or module intended for installation integral with, or forming a part of, the building roof structure fall away in the form of glowing particles; or

d) There be sustained flaming of the module or module."

As a result of catastrophic fires in California, State Fire Officials are considering a statewide requirement for Class A fire rating of all roofing products including photovoltaic (PV) modules. To date, there are few Class A rated PV modules or building-integrated photovoltaic (BIPV) products from all the several hundred listed modules. At present, the effect of fire on UL 790 fire Class A rated roofing materials when Class C rated PV modules are installed is not

[11] http://ulstandardsinfonet.ul.com/

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well understood. For instance will a Class C rated module reduce the fire resistance performance and/or fire rating of some Class A rated roof systems? If so, which roof systems are impacted and to what extent?

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RESEARCH INVESTIGATION

RESEARCH OBJECTIVES

The objectives of this research project:

- *Develop baseline data on the fire exposure during standard fire tests such as UL 790*
- *Determine the effect of installation parameters for elevated PV modules on roofs*
- *Document the impact of lesser fire rated elevated PV modules on common roofing materials*

To meet these objectives, the research was conducted in three phases as depicted in Figure 5.

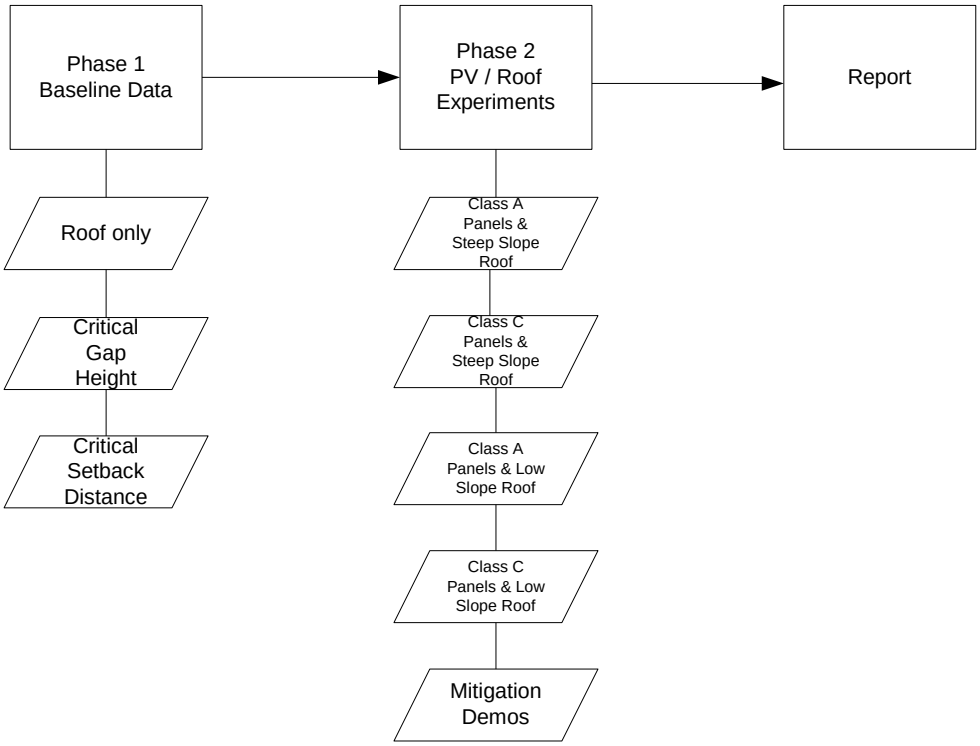

Figure 5 Outline of Research Investigation

For Phase 1, the interaction of the module and the roof as an assembly was investigated during standard fire tests described within UL 790. Experiments were carried out using instrumented simulated noncombustible PV panel and roof deck to study the influence on fire hazard of different PV installation parameters such as (i) gap or standoff height above the roof, (ii) PV set back from the roof edge, and (iii) orientation of the non-combustible mounting rails for the PV module. In addition, a limited number of experiments were conducted using actual PV modules mounted on Class A rated roof shingles to demonstrate

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impact to the fire classification rating of roofing during Spread of Flame and Burning Brand tests.

Based on the results of the Phase 1 tests, a Phase 2 test program was designed to investigate the fire performance of fire rated roof mounted PV modules on specific Fire Class roofing materials.

TECHNICAL PLAN

The technical plan consisted of the following tasks for each phase of this investigation:

Phase 1:

Task 1 - Select and acquire test samples.

Task 2 - Perform experiments with noncombustible roof and noncombustible PV module surrogate.

Task 3 - Perform limited experiments with combustible roofs and combustible PV modules to demonstrate effects on the fire classification rating of roof assemblies using the spread of flame spread and burning brand tests.

Phase 2:

Task 4 - Perform experiments with various fire classification rated classified roof assemblies/PV module combinations.

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PHASE 1/ TASK 1 – SELECT AND ACQUIRE TEST SAMPLES

ROOFING MATERIALS

A review of commercially available roofing products was performed in an effort to develop a representative sample of various technologies applied to low and high-sloped roofing systems. Within Class A, roofing materials exhibit varying degrees of performance and can be further described as nominal or good performance. One example is the difference between standard three tab shingles (nominal) as compared to architectural shingles (e.g., laminated or dimensional shingles). The architectural shingles are typically constructed of a heavier base mat and are multi layered, and typically perform better in fire classification tests than the standard three tab shingles.

As result of the survey, 5 different roofing products (along with one noncombustible board) were selected for evaluation. The materials were purchased from a local retailer. The roofing materials are listed in Table 2. The fire performance ratings for roofing material ratings were obtained from UL database based on the manufacturers of the selected roofing materials.

Table 2 - Description of Roof Assemblies

Test Material	Description	Rating
Shingle	Asphalt impregnated fiberglass mat three tab shingle	A
Shingle	Asphalt impregnated fiberglass laminated mat or 'architectural' shingle	A
Shingle	Cedar shake shingle	C
Membrane	2" thick rigid Isocyanurate foam covered with a single ply of Ethylene propylene diene monomer (EPDM) membrane	A
Hot Mopped	Asphalt-coated glass-fiber mat (felt) – Type G1 (ply sheets), and a Type G3 (granular-surfaced cap sheets)	A
Board	4 x 8 ft. non combustible board	A

PHOTOVOLTAIC MODULES

PV modules were donated by manufacturers and provided to UL by Solar ABCs. The PV modules were not identified with respect to the model or their manufacturer. The fire performance ratings for the PV modules were simply assigned based on the observed construction of the module i.e., metal back plane = Class A, plastic back plane = Class C.

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PHASE 1/TASK 2 – EXPERIMENTS WITH NONCOMBUSTIBLE ROOF AND PV MODULE

The objective of this task was to develop fire characteristics of a roof mounted PV module on a roofing assembly subject to the standard fire tests such as UL 790/UL 1703.

TEST MATRIX

Based upon discussion with SolarABCs representatives, installation variables were selected that would be expected to influence the fire performance of a rack mounted PV module on a roof. These included (i) installation gap between the bottom of the PV module and the roof surface and (ii) distance of the installed PV module from the leading edge or setback of the roof. Specific gap and setback distances selected for this study are shown in Table 3.

Table 3 – Selected Gap and Setback Distances

Item	Selected Distances (in.)
Gap	2.5, 5, 10
Setback	0, 12, 24

A test matrix was developed as presented in Table 4. The test matrix included a baseline test on the roof assembly to develop temperature and heat flux data from the flame exposure for comparative purposes.

Table 4 – Phase 1 Test Matrix

Test Run #	Gap (in)	Setback (in)	Rail
1	No Module	No Module	N/A
2	2 1/2	0	N/A
3	2 12	12	N/A
4	2 1/2	24	N/A
5	5	0	Vertical
6	5	0	Horizontal
7	10	0	N/A
8	10	12	N/A
9	10	24	N/A
10	5	0	N/A
11	5	24	N/A
36	5	12	N/A

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TEST SET-UP

In this task, both the roof and the PV module were simulated using a noncombustible board to isolate the influence of the installed module on the thermal impact to the roofing assembly. Experiments were conducted using UL's standard roofing fire test assembly.

The noncombustible roof assembly was constructed with frame of 2 x 4 in. wood studs as supports. The surface of the roof was covered with ¼ in noncombustible material. The simulated PV module was constructed with a frame of 2 x 4 in. wood studs as supporting members. The top and bottom surfaces of the structure were covered with ¼ in. noncombustible material. The leading edge of the simulated PV module was protected with ¼ in noncombustible material.

All tests were performed in this investigation at a roof slope of 5 inches vertical to the horizontal foot, 5/12 (23°) with the PV module configured parallel to the roof. The simulated PV module was supported on the roof surface with metal rods. The supports could be adjusted to control the gap between the module and the top of the roof surface. A typical set up is shown in Figure 6.

Figure 6 Photograph of Noncombustible PV Module & Roof Deck Test Fixture

INSTRUMENTATION

The test assembly was fitted with thermocouples, heat flux gages and bi-directional velocity probes as shown in Figure 7.

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Thermocouples

The thermocouples were type K (chromel–alumel, 24-gauge, fiberglass insulated with exposed tip) fabricated by UL laboratory staff. The thermocouples were mounted along the centerline of the roof deck and simulated PV module surface.

Heat Flux Gauges

Heat flux gauges were manufactured by Medtherm Corporation of Huntsville, AL, model 64-5SB-20, 0-50 kW/m^2 range. The gauges were mounted on the surface of the roof deck along the centerline.

Bi-directional probe and Pressure Transducer

The bi-directional probe was manufactured by Select Metals, Elmhurst, IL. The pressure transducer was manufactured by MKS Instruments of Methuen, MA, model 220DD-0000-1B2B, 0-1 Torr (0-1 mm/hg) range. The bi-directional probe was mounted along the centerline and in the approximate middle of the gap formed by the roof deck and simulated PV module.

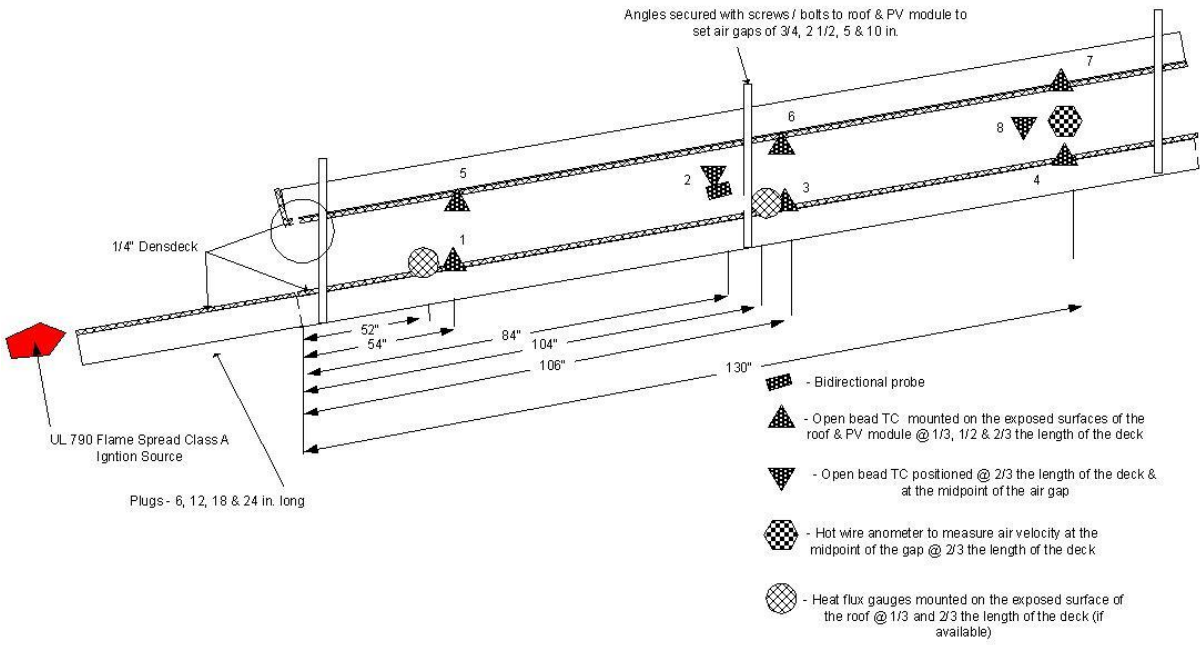

Figure 7 Illustration of Instrumentation

Video and Photography

The experiments were documented using video and still photography.

Data Acquisition

An automated data acquisition system was used to record the temperature, heat flux, and velocity data during the tests at a scan rate of 1 s.

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TEST PROCEDURE

A baseline test was first conducted to develop temperature and heat flux data from the flame exposure in accordance with Class A Spread of Flame test described in UL 790. For all other tests, a simulated PV module was mounted to the roof with the selected gap and setback distances. The assembly was exposed to flame exposure in accordance with Class A Spread of Flame test described in UL 790. The test duration was 5 minutes.

RESULTS

The temperature and heat flux data from the fire tests are summarized in Table 5 for the twelve experiments.

Table 5 - Results for Spread of Flame test on simulated PV module and roof

Assembly ID	Gap (in)	Setback (in)	Rail	Temperature @ 5 mins			Average Temp Rise (last 30 sec)			Heat Flux Max	
				1	3	4	1	3	4	1	2
				(°F)	(°F)	(°F)	(°F)	(°F)	(°F)	(kW/m²)	(kW/m²)
1	N/A	N/A	N/A	502	177	151	371	93	65	15	3
7	2 1/2	0	N/A	948	465	362	859	355	260	23	9
9	2 12	12	N/A	747	384	292	679	313	211	16	8
11	2 1/2	24	N/A	457	294	232	261	175	135	7	6
12	5	0	Vertical	974	768	562	-	-	-	29	22
17	5	0	Horiz.	1008	751	604	909	688	513	34	17
22	10	0	N/A	630	373	327	-	-	-	19	9
24	10	12	N/A	551	374	332	458	292	246	17	7
26	10	24	N/A	490	317	280	381	223	183	11	7
34	5	0	N/A	1066	719	576	939	637	508	41	25
35	5	24	N/A	600	430	369	499	334	279	12	9
36	5	12	N/A	865	518	406	703	428	316	23	12

Photographs from select test runs are presented in Figure 8 through Figure 12. Of particular interest is physical capture or deflection of the source flames in the channel formed between the bottom of the module and the top of the roof surface.

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Figure 8 Photograph of Spread of Flame test baseline (Assembly 1)

Figure 9 Photograph of Non-combustible Roof and Simulated PV Module Spread of Flame Test with 0" Setback and 10" Gap (Assembly 22)

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Figure 10 Photograph of non-combustible Roof and Simulated PV Module Spread of Flame test with 0" Setback and 2.5" Gap (Assembly 7)

Figure 11 Photograph of non-combustible Roof and Simulated PV Module Spread of Flame test with 0" Setback and 5" Gap (Assembly 12)

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Figure 12 Photograph of Non-combustible Roof and Simulated PV Module Spread of Flame test with 12" Setback and 5" Gap (Assembly 36)

ANALYSIS OF DATA

Next, the temperature and heat flux data are analyzed. For the figures in this section, the legend may be interpreted as follows:

- *TC – Thermocouple data*
- *HF – Heat flux gauge data*
- *A-xx – Assembly ID (Table 5)*

For example, TC-1 A-1 refers to thermocouple position 1 of assembly 1 and HF-1 A-34 refers to heat flux gage position 1 of assembly 34. Sensor numbers are based upon Figure 7.

Figure 13 shows the temperature measurements from forward thermocouples placed on the noncombustible roof. From this figure, it is clear that the 5" gap (A-34) leads to the highest temperatures followed by the 2.5" gap (A-7). The 10" gap (A-22) case is approximately 100° F above the roof-only case (A-1). For all these cases, it can be seen that there is an initial rapid rise – within 20 seconds - in temperatures followed by a more gradual increase over the 300 second testing period.

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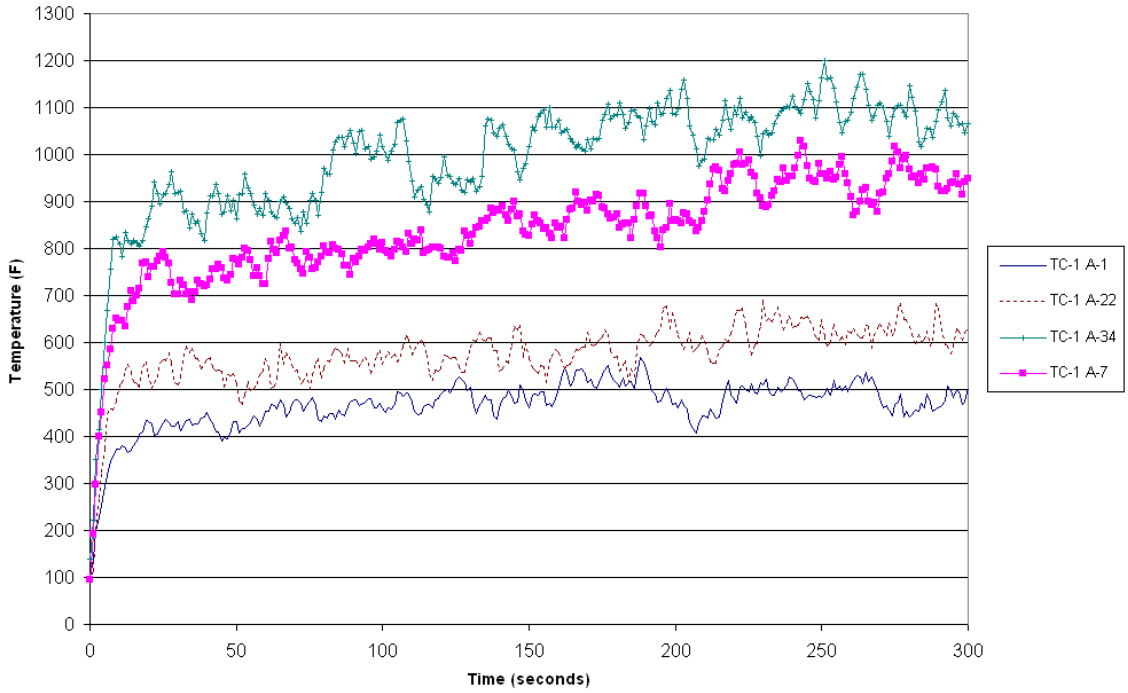

Figure 13 Influence of Gap Distance on Roof Temperature – 54 inches from the Roof Leading Edge

Figure 14 shows the temperatures for two thermocouples placed along the noncombustible roof located at 106 and 130 inches from the roof leading edge. For all cases, the thermocouple reading at the middle was higher than that of the end of the roof. Once again, the 5" gap case generated the highest temperatures along the roof surface while the 2.5" gap was the next lowest. The thermocouple reading for the end of the 2.5" gap case was very close to the readings from both thermocouples for the 10" gap case. The readings for the 10" gap case show that the difference between the middle and end thermocouple measurements was much less than that for the two previous cases. Finally, the case with roof-only component shows the lowest temperatures.

Figure 15 shows readings from the forward thermocouple located on the underside of the non-combustible simulated PV module. For the case with roof only, the reading is simply that of ambient air. These readings display similar trends and values as seen in Figure 13.

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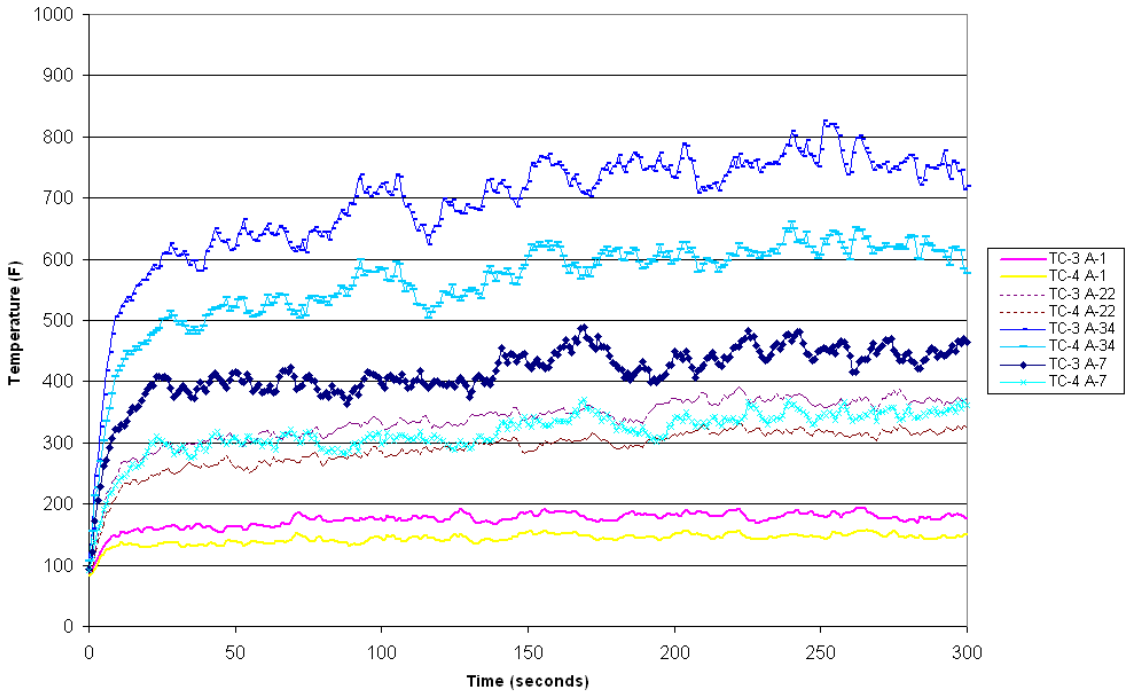

Figure 14 Influence of Gap on Roof Temperature: 106 and 130 inches from the Leading Edge

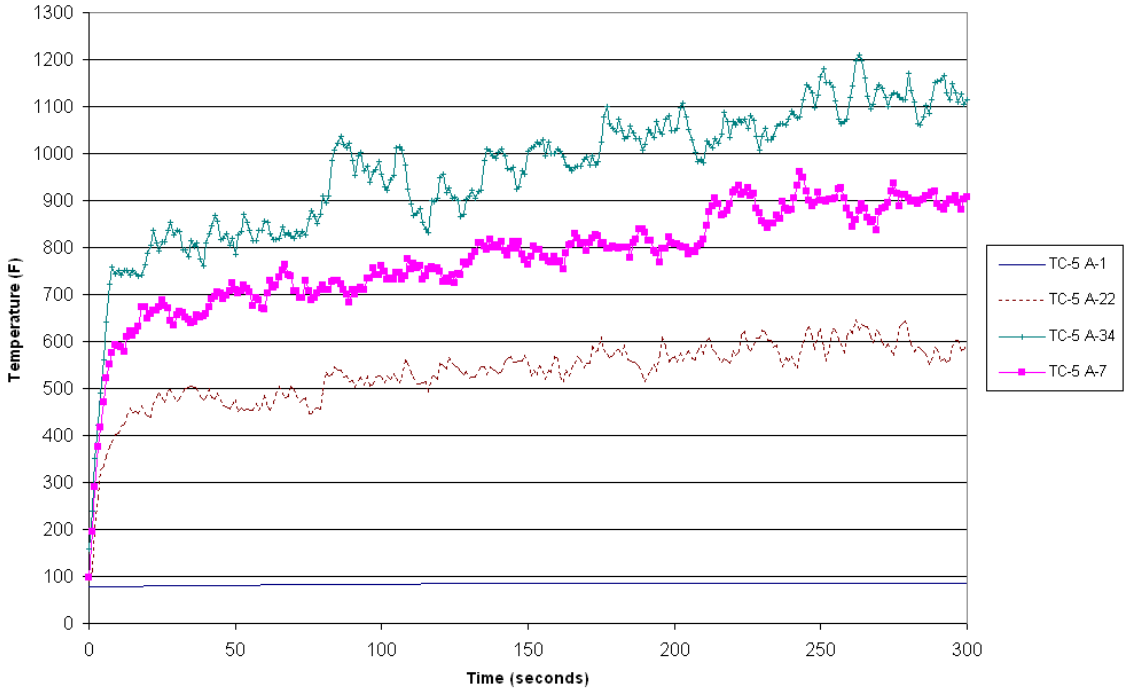

Figure 15 Temperature a the Bottom Surface Simulated PV Module – 54 inches from the Roof Leading Edge

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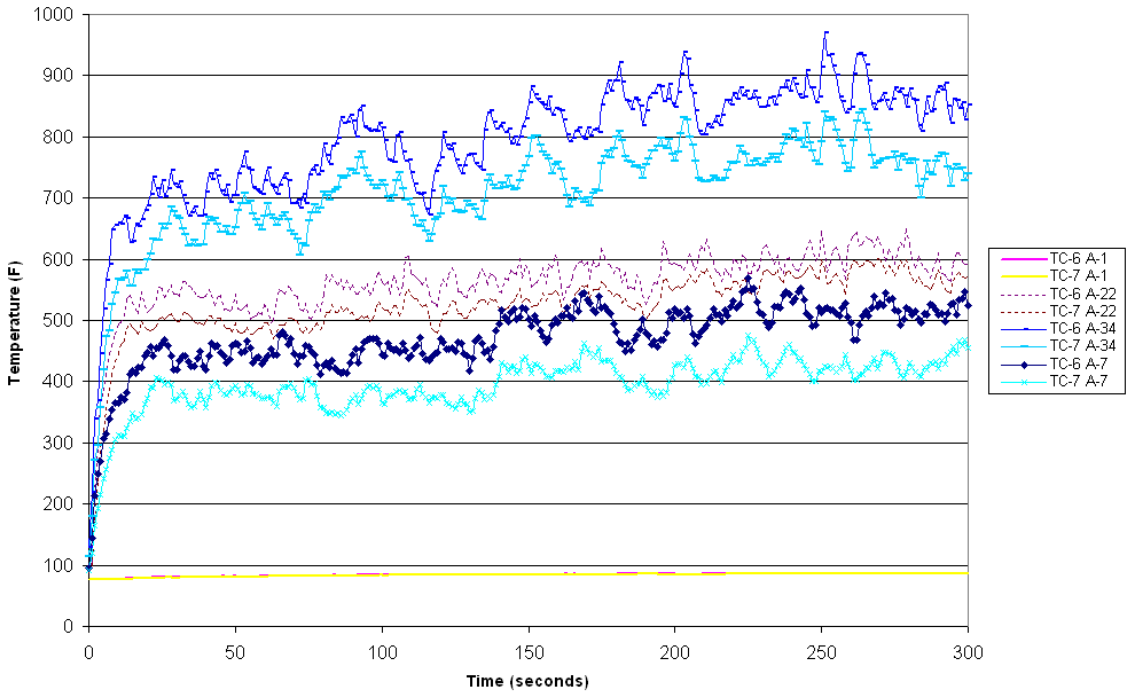

Figure 16 Temperature at Bottom Surface of Simulated PV Module: 104 and 130 inches from the Roof Leading Edge

Figure 16 shows readings from thermocouples located at 106 and 130 inches from the leading edge on the bottom surface of the noncombustible simulated PV module. It is interesting to note that these temperatures are higher than those recorded by the middle and end thermocouples on the surface of the noncombustible roof for each respective case. The 5" gap case still generated the highest temperatures. However, the next highest temperatures were generated for the 10" gap case, not the 2.5" gap case, as was seen for the roof surface temperature readings in Figure 13.

Figure 17 and Figure 18 display heat flux gauge readings of the noncombustible roof surface at 54 and 106 inches from the roof leading edge, respectively. Matching the trends seen in the temperature, the 5" gap case generated the largest values of heat flux after a very rapid rise. In Figure 17 these values reached as high as 40 kW/m^2 especially near the end of the testing period. Even the case without a noncombustible roof component generated heat flux as high as 15 kW/m^2 for a very brief moment while most of the values oscillated about 10 kW/m^2.

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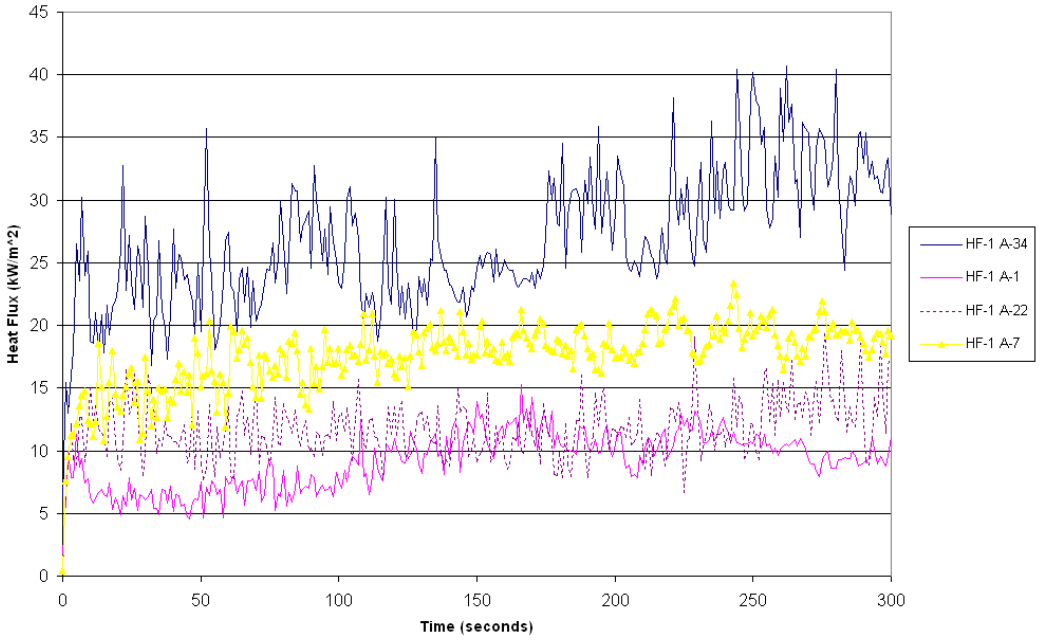

Figure 17 Heat Flux on Roof Surface – 54 inches from the Roof Leading Edge

In Figure 18 once again, the 5" gap case shows the largest amount of heat flux for the middle gauge with values reaching approximately 20 kW/m², almost half that of the forward gage. However the heat flux values for the 2.5" and 10" gaps were indistinguishable while the no PV component case resulted in a nearly steady value of 2-3 kW/m².

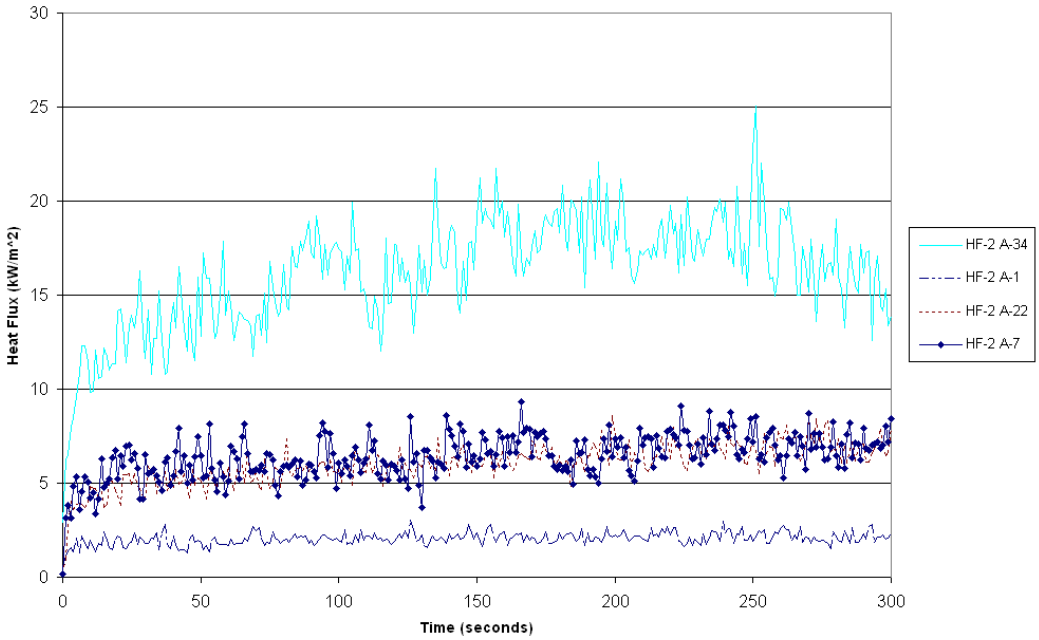

Figure 18 Heat Flux on the Roof: 106 inches from the Roof Leading Edge

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Figure 19 shows the effect of the leading edge distances on the temperatures measured on the thermocouple positioned near the front of the non-combustible roof surface for a gap of 5". This data shows the drop in temperature that occurs as a result of placing the leading edge of the non-combustible simulated PV module further from the roof leading edge and subsequently the fire.

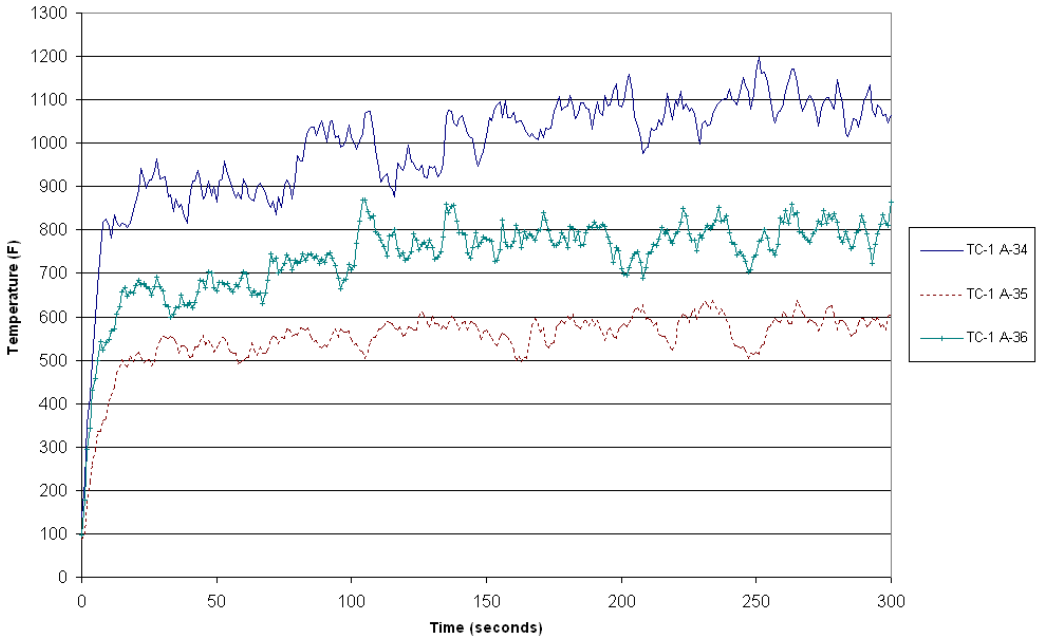

Figure 19 Influence of Setback on Roof Temperature: 54 inches from the Roof Leading Edge

Figure 20 shows the temperature results for thermocouples placed in the middle and near the end of the non-combustible roof component as a function of leading edge distances for a gap of 5".

The greater the distance of the leading edge of the simulated PV from the leading edge of the roof, the lower will be the surface temperature along the roof. For the 24" leading edge test, the recorded temperature for the leading thermocouple on the roof surface was basically following the test temperatures seen for the 10" gap with no leading edge. Clearly as the setback distance is increased further, it effectively behaves as a roof without PV module for this particular fire setup. These results are expected to hold for the typical ranges of PV/roof gap sizes.

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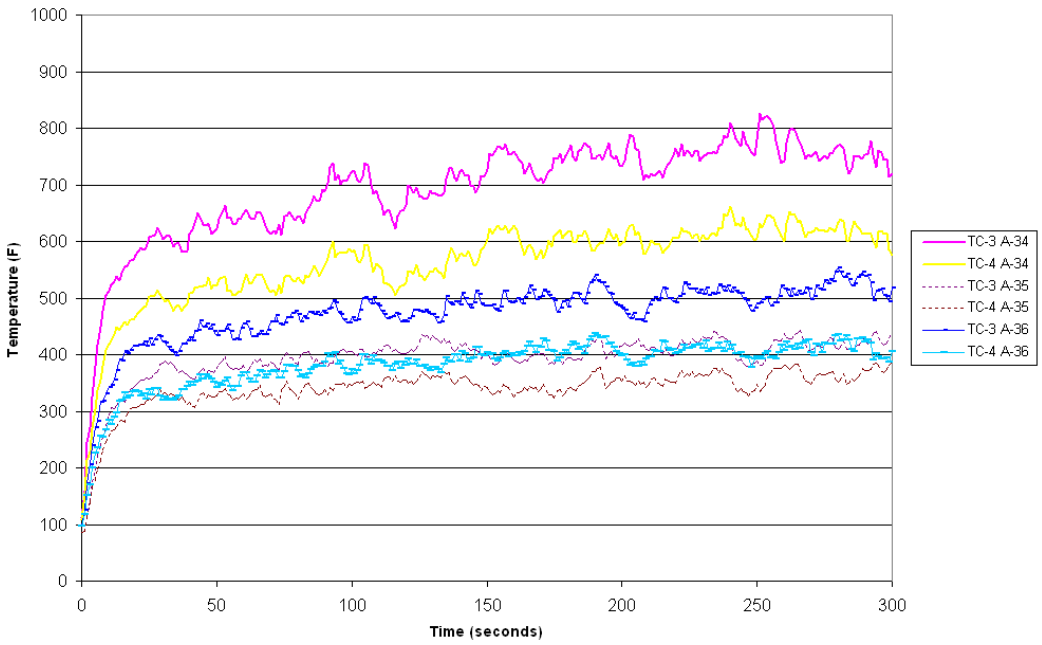

Figure 20 Influence of Setback on Roof Temperature: 106 and 130 inches from the Roof Leading Edge

Figure 21 shows the temperature from the 54-inch location thermocouple on the underside the noncombustible simulated PV module for a gap of 5" as a function of setback. Here again, the same trend is observed for simulated PV temperatures as was seen for the roof temperatures in Figure 13.

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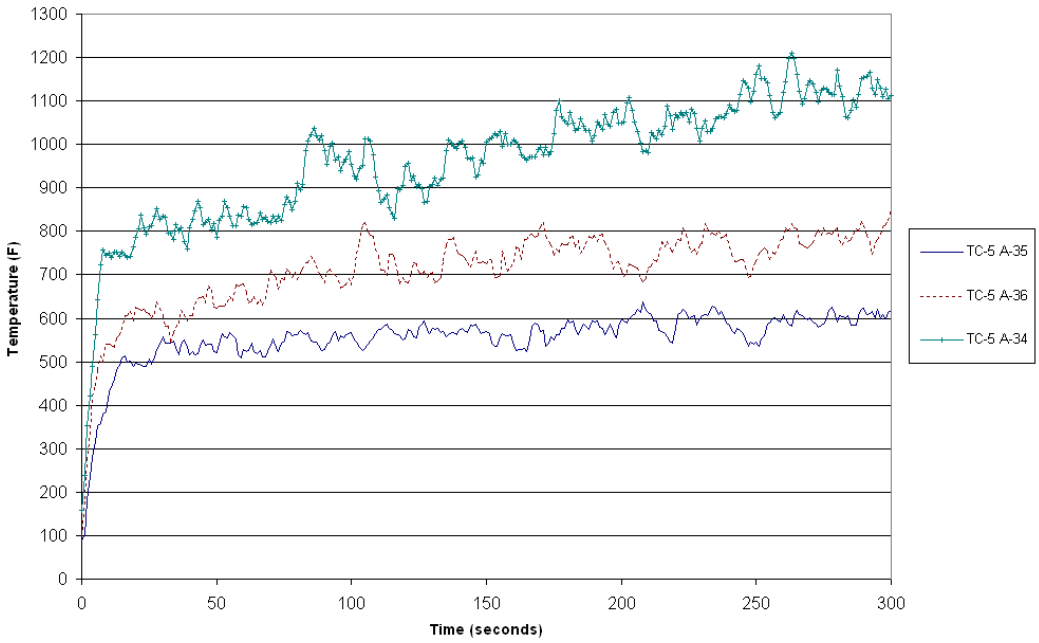

Figure 21 Influence of Setback on Simulated PV Module temperature: 54 inches from the Roof Leading Edge

Figure 22 shows the temperatures from thermocouples placed near the middle and the end of the underside of the noncombustible PV component for a gap of 5" as a function of setback distance.

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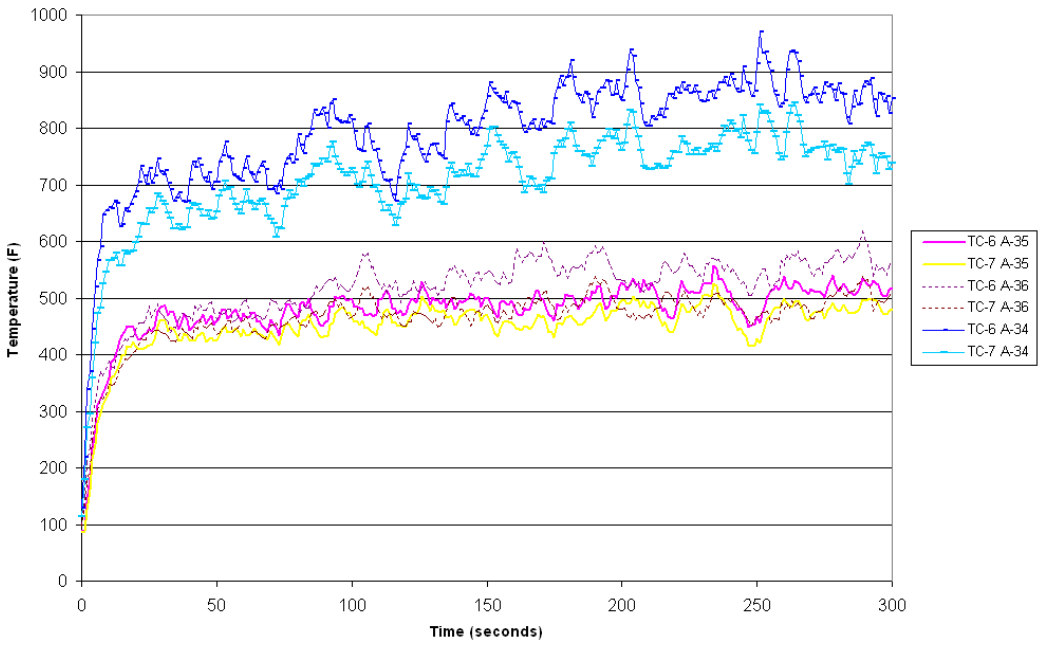

Figure 22 Influence of Setback on Simulated PV Module temperature: 106 and 130 inches from Roof Leading Edge

For these measurements, the same drop in temperature is observed as the setback distance is increased. However, for this particular case, changing the setback distance from 12" to 24" has minimal effect on the measured temperatures.

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PHASE 1/TASK 3 LIMITED EXPERIMENTS WITH COMBUSTIBLE ROOFS AND PV

OBJECTIVE

The objective of this task was to conduct experiments on a limited number of PV module/roof combinations to demonstrate if the fire classification rating of a roof system is affected by the presence of a rack mounted PV module.

EXPERIMENTAL PARAMETERS

Experiments were conducted using the Spread of Flame and Burning Brand ignition sources as specified in UL 790 and UL 1703. The following combinations were demonstrated:

- Spread of Flame Test - Class A Shingle Roof w/ Class C PV, Vertical Mounts, 0" Set Back, 5.0" Gap
- Spread of Flame Test - Class A Shingle Roof w/ Class C PV, Horizontal Mounts, 0" Set Back, 5.0" Gap
- Burning Brand on Module - Class A Shingle Roof w/ Class C PV, 0" Gap – Burning Brand on Module
- Burning Brand Between Module and Roof - Class A Shingle Roof w/ Class C PV, 5" Gap

To quantify the effects of these variables, a series of demonstration experiments were conducted to document the results of standard Flame Spread and Burning Brand tests. Experiments were conducted using the standard method and test fixture as outlined in UL 790 and UL 1703. Modules were mounted above the roof surface at a gap of 5 inches.

RESULTS

- The experiment conducted subjecting a Class A shingle roof with a Class C PV incorporating *vertical* supports to the Spread of Flame ignition source resulted in flames extending beyond the roof deck in excess of 8 ft. – not in conformance with Class A requirements. (Figure 23 to Figure 26)

- The experiment conducted subjecting a Class A shingle roof with a Class C PV incorporating *horizontal* supports to the Spread of Flame ignition source resulted in flames extending beyond the roof deck in excess of 8 ft. – not in conformance with Class A requirements. (Figure 27 to Figure 30)

- The experiment conducted subjecting a Class A shingle roof with a Class C PV to a Class A burning brand positioned on the module surface was in conformance with the requirements. (Figure 31 to Figure 34)

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- The experiment conducted subjecting a Class A shingle roof with a Class C PV to a Class A burning brand positioned between the PV module surface and the roof was in conformance with the requirements. (Figure 35 to Figure 38)

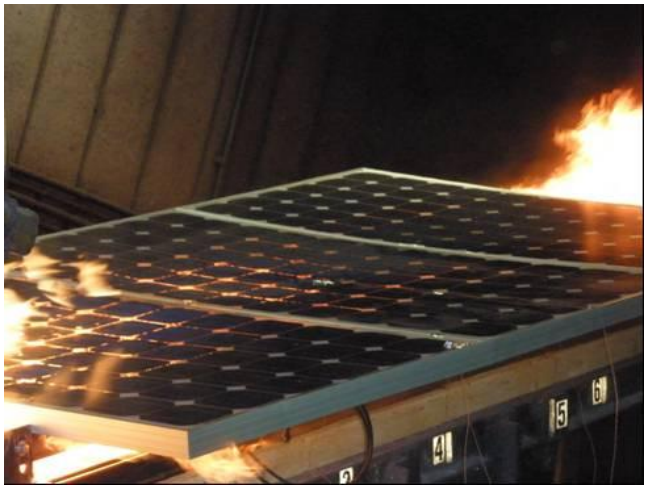

Figure 23 Photograph of Spread of Flame Test for Class A Shingle Roof with Class C PV and Vertical Mounts and 0" Leading Edge and 5" Gap

Figure 24 Photograph of Spread of Flame Test for Class A Shingle Roof with Class C PV and Vertical Mounts and 0" Leading Edge and 5" Gap

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Figure 25 Photograph of Spread of Flame Test for Class A Shingle Roof with Class C PV and Vertical Mounts and 0" Leading Edge and 5" Gap

Figure 26 Photograph of Spread of Flame Test of Class A Shingle Roof with Class C PV and Vertical Mounts and 0" Leading Edge and 5" Gap

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Figure 27 Photograph of Spread of Flame Test for Class A Shingle Roof with Class C PV and Horizontal Mounts and 0" Leading Edge and 5" Gap

Figure 28 Photograph of Spread of Flame Test for Class A Shingle Roof with Class C PV and Horizontal Mounts and 0" Leading Edge and 5" Gap

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Figure 29 Photograph of Spread of Flame Test for Class A Shingle Roof with Class C PV and Horizontal Mounts and 0" Leading Edge and 5" Gap

Figure 30 Photograph of Spread of Flame Test for Class A Shingle Roof with Class C PV and Horizontal Mounts and 0" Leading Edge and 5" Gap

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Figure 31 Photograph of Burning Brand on Module for Class A Shingle Roof with Class C PV and 0" Gap

Figure 32 Photograph of Burning Brand on Module for Class A Shingle Roof with Class C PV and 0" Gap

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Figure 33 Photograph of Burning Brand on Module for Class A Shingle Roof with Class C PV and 0" Gap

Figure 34 Photograph of Burning Brand on Module for Class A Shingle Roof with Class C PV and 0" Gap

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Figure 35 Photograph of Burning Brand Between Module and Roof for Class A Shingle Roof with Class C PV and 5" Gap

Figure 36 Photograph of Burning Brand Between Module and Roof for Class A Shingle Roof with Class C PV and 5" Gap

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Figure 37 Photograph of Burning Brand between Module and Roof for Class A Shingle Roof with Class C PV and 5" Gap

Figure 38 Photograph of Burning Brand between Module and Roof for Class A Shingle Roof with Class C PV and 5" Gap

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ANALYSIS

Spread of flame experiments conducted on Class A roof with Class C rated PV mounted on horizontal (parallel to roof edge) or vertical (perpendicular to roof edge) support rails illustrated no difference in the flame spread – both resulted in noncompliant flame spread in excess of the required maximum of 6 ft for Class A rated roof systems. These limited series of experiments indicate that the fire rating of the Class A roof is compromised in this situation.

Burning brand experiments conducted with a Class A brand positioned either on the surface of the module or on the surface of the roof resulted in compliant results for Class A requirements. This initial series of experiments indicate the fire rating of the Class A roof is not affected with a rack mounted Class C PV module. When the brand resides on the module which is elevated above the roof, there is a clearly a buffer helping increase fire resistance to fire brands. With the brand placed on the roof, the Class C PV burns and sags, creating an opening, which allows the flames to vent vertically. If the nature of the fire growth and spread on the PV should alter the ability of venting, then it might be possible to reduce the fire performance. For this reason, some of these tests were repeated in Phase 2.

PHASE 2/TASK 4 - EXPERIMENTS WITH VARIOUS FIRE-RATED ROOF ASSEMBLIES/PV MODULE COMBINATIONS

OBJECTIVE

The objective of this task was to conduct experiments, extending the work from Phase 1, on a variety of PV module/roof combinations to demonstrate how a PV module installed above the roof affects the classification of a fire-rated roof system.

EXPERIMENTAL PARAMETERS

Experiments were conducted using the Spread of Flame and Burning Brand ignition sources as specified in UL 790 and UL 1703. For the spread of flame test, the roofing material and the PV fire rating were the experimental parameters (Table 6). Similarly, for the Burning Brand test, the roofing material and the PV fire rating were experimental parameters along with the location of the Burning Brand (Table 7).

RESULTS

All spread of flame experiments (Class C PV / Class A 3 tab shingle roof, Class C P V / Class C wood shake shingle roof, Class A PV / Class A membrane roof, Class C PV / Class A laminated shingle roof, and Class C PV / Class A built-up roof) resulted in flame propagation beyond the length of the roof deck (>8 ft), which was not in conformance with the requirements of Class A roofing systems (<6 ft).

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Table 6 Phase 2 Spread of Flame Test Results

Assembly ID	Gap (in)	Setback (in)	Roof Rating	Roof Slope (in/in)	PV Rating	Flame Spread Data	
						Distance (feet)[1]	Time (min:sec)
5	5	0	A - 3 Tab Shingle	5/12	C	>8	4:17
1	5	0	Noncombustible	5/12	C	>8	2:03
7	5	0	C - Wood Shake	5/12	C	>8	0:47
14	5	0	A - membrane	0.5/12	A	>8	1:00
3	5	0	A - Architectural Shingle	5/12	C	>8	1:57
11	5	0	A - Hot Mopped	0.5/12	C	>8	1:43
19	5	0	Noncombustible	5/12	A	>8	5:47

Note: 1 – The flames extended beyond the length of the deck (8 ft).

The Burning Brand experiment conducted with a Class C PV/Class A shingle roof with the brand positioned on the surface of the module was in conformance with the requirements for Class A roofs. The Burning Brand experiment conducted with a Class C PV/Class C wood shake shingle roof with the brand positioned on the surface of the roof was not in conformance with the requirements for Class C roofs. Tests conducted with a Class C PV/Class A shingle roof with the brand positioned on the roof surface resulted in inconsistent results – one in conformance, one not in conformance with the requirements for Class A roofs.

Table 7 Phase 2 Burning Brand Test Results

Assembly ID	Brand Location	Gap (in)	Setback (in)	Rail	Roof Rating	PV Rating	Duration (Hr:Min:Sec)	Pass / Fail
1	PV surface	5	0	Horizontal.	A - 3 Tab Shingle	C	0:45:00	Pass
2	Roof surface	5	0	Horizontal	A - 3 Tab Shingle	C	1:30:16	Pass
4	Roof surface	5	0	Horizontal	C - Wood Shake	C	0:30:09	Fail
3	Roof surface	5	0	Horizontal	A - 3 Tab Shingle	A	0:16:47	Fail

Visual results are provided in the following photographs.

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Figure 39 Photograph of Spread of Flame Test for Class C Wood Shake Roof with Class C PV and 0" Leading Edge and 5" Gap – before start of experiment

Figure 40 Photograph of Spread of Flame Test for Class C Wood Shake Roof with Class C PV and 0" Leading Edge and 5" Gap

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Figure 41 Photograph of Spread of Flame Test for Class A Membrane Roof with Class A PV and 0" Leading Edge and 5" Gap – prior to start of experiment

Figure 42 Photograph of Spread of Flame Test for Class A Membrane Roof with Class A PV and 0" Leading Edge and 5" Gap

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Figure 43 Photograph of Spread of Flame for Class A Laminated (Architectural) Shingle Roof with Class C PV with 0" Leading Edge and 5" Gap – before start of experiment

Figure 44 Photograph of Spread of Flame for Class A Laminated (Architectural) Shingle Roof with Class C PV with 0" Leading Edge and 5" Gap

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Figure 45 Photograph of Spread of Flame for Class A Built Up Roof (Hot Mopped Asphalt) with Class C PV and 0" Leading Edge and 5" Gap – before start of experiment

Figure 46 Photograph of Spread of Flame for Class A Built Up Roof (Hot Mopped Asphalt) with Class C PV and 0" Leading Edge and 5" Gap

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Figure 47 Burning Brand Test for Class A Shingle (3 tab) with Class C PV where Class A brand is located on the surface of the roof under the module

Figure 48 Burning Brand Test for Class A Shingle (3 tab) Roof with Class C PV where Class A brand is located on the surface of the roof under the module

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Figure 49 Underside of Roof Deck View: Burning Brand Test for Class A Shingle (3 tab) roof with Class C PV where Class A brand was located on the surface of the roof under the module

Figure 50 Burning Brand Test for Class C Wood Shake Roof with Class C PV where Class C brand was located on the surface of the roof

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Figure 51 Burning Brand Test for Class C Wood Shake Roof with Class C PV where Class C brand was located on the surface of the roof

Figure 52 Underside of Roof Deck View: Burning Brand Test for Class C Wood Shake Roof with Class C PV where Class C brand was located on the surface of the roof

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Figure 53 Burning Brand Test for Class A Shingle (3 tab) Roof with Class A PV where Class A brand was located on the surface of the roof under the module

Figure 54 Burning Brand Test for Class A Shingle (3 tab) Roof with Class A PV where Class A brand was located on the surface of the roof under the module

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Figure 55 View of Deck Underside: Burning Brand Test for Class A Shingle (3 tab) Roof with Class A PV where Class A brand was located on the surface of the roof under the module

ANALYSIS

All Spread of Flame experiments (Class C PV / Class A 3 tab shingle roof, Class C P V / Class C wood shake shingle roof, Class A PV / Class A membrane roof, Class C PV / Class A laminated shingle roof, and Class C PV / Class A built-up roof) resulted in flame spreads that were noncompliant for Class A rating. These Phase 2 test results validate the Phase 1 experiments and strongly point out that the fire rating of the Class A roof is decreased when PV modules are mounted above a roof with a gap allowing for fire spread between the products.

This series of Burning brand experiments indicate that wood shake shingle fire performance is decreased when a Class C PV module is elevated above the roof and the fire is located between the module and the roof. In the case of a Class C PV elevated above a Class A shingle roof the fire performance is not affected when the fire is located on the surface of the module. In the case of a Class C PV / Class A shingle roof with the fire located between the module and the roof the fire performance may or may not be decreased.

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SUMMARY OF FINDINGS

An analysis of the data generated by the experiments carried out in this study point to the following key findings:

- A baseline of the temperature and heat flux exposure to the roof under the UL 790 test conditions was established and is shown in Figure 56.

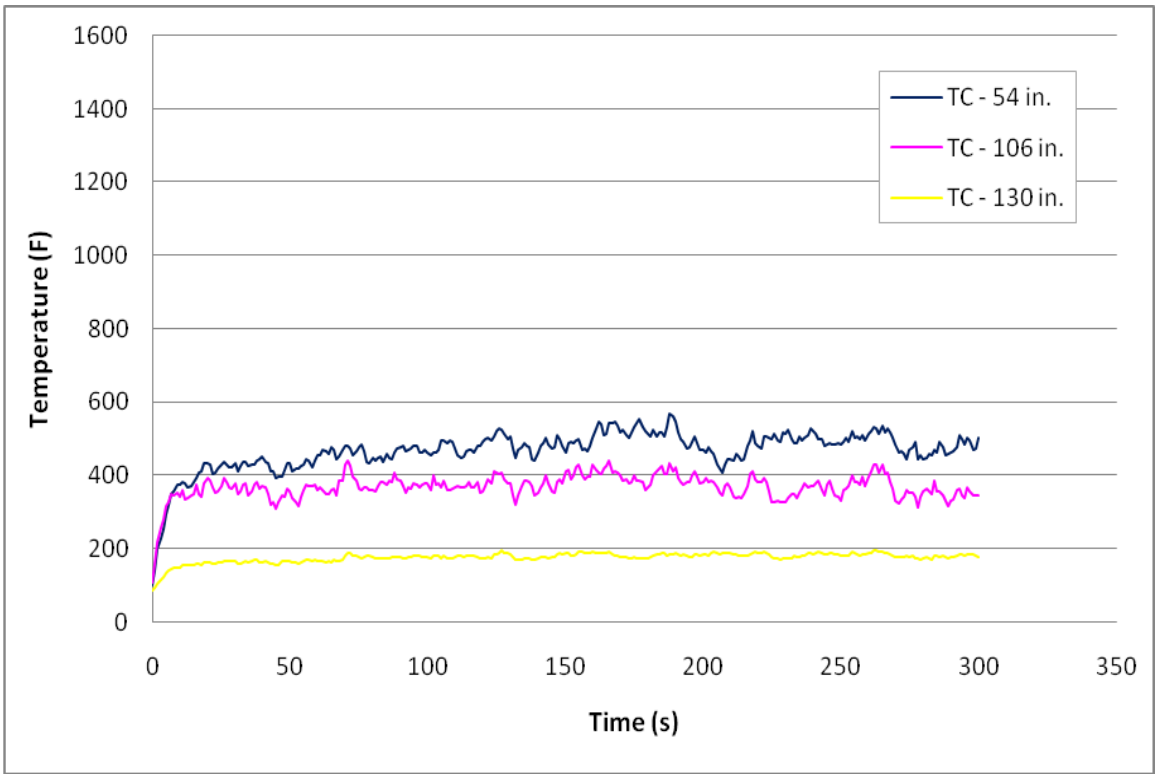

Figure 56 - Baseline Temperature

- The effect on roof temperature of a PV module mounted at a height of 5 inches above the roof surface and varying the setback of the module from the edge of the roof was measured and are shown in Figures 57 through 59.

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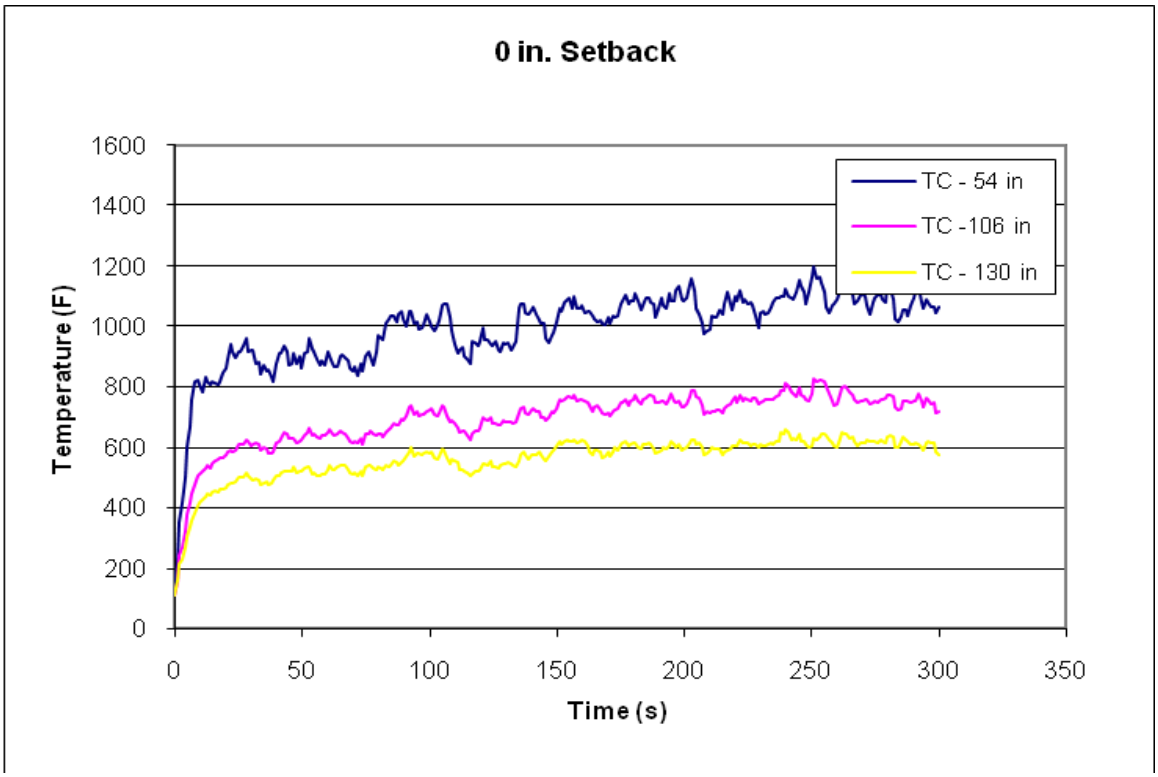

Figure 57 - Temperature of Roof with PV Module Mounted at 5" with 0" setback

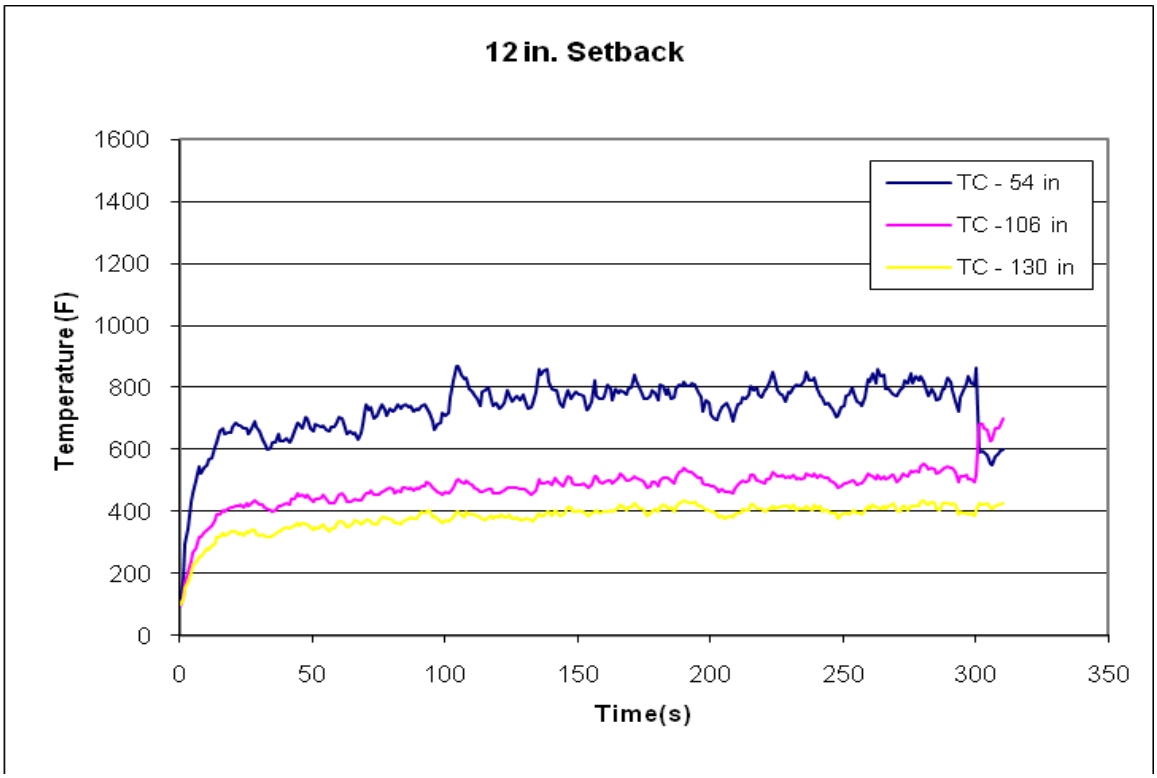

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Figure 58 - Temperature of Roof with PV Module Mounted at 5" with 12" setback

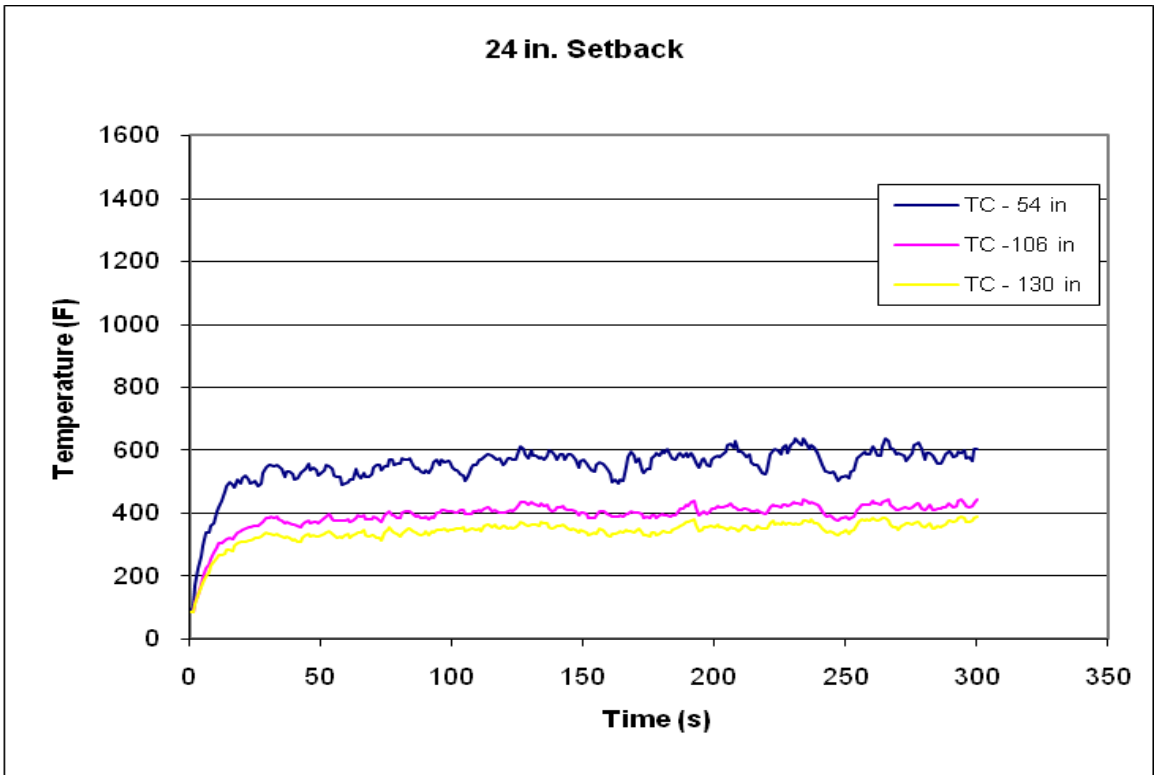

Figure 59 - Temperature of Roof with PV Module Mounted at 5" with 24" setback

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- The effect various gaps on roof temperature of a PV module mounted at heights of 2.5, 5, and 10 inches above the roof was measured and is shown in Figure 60.

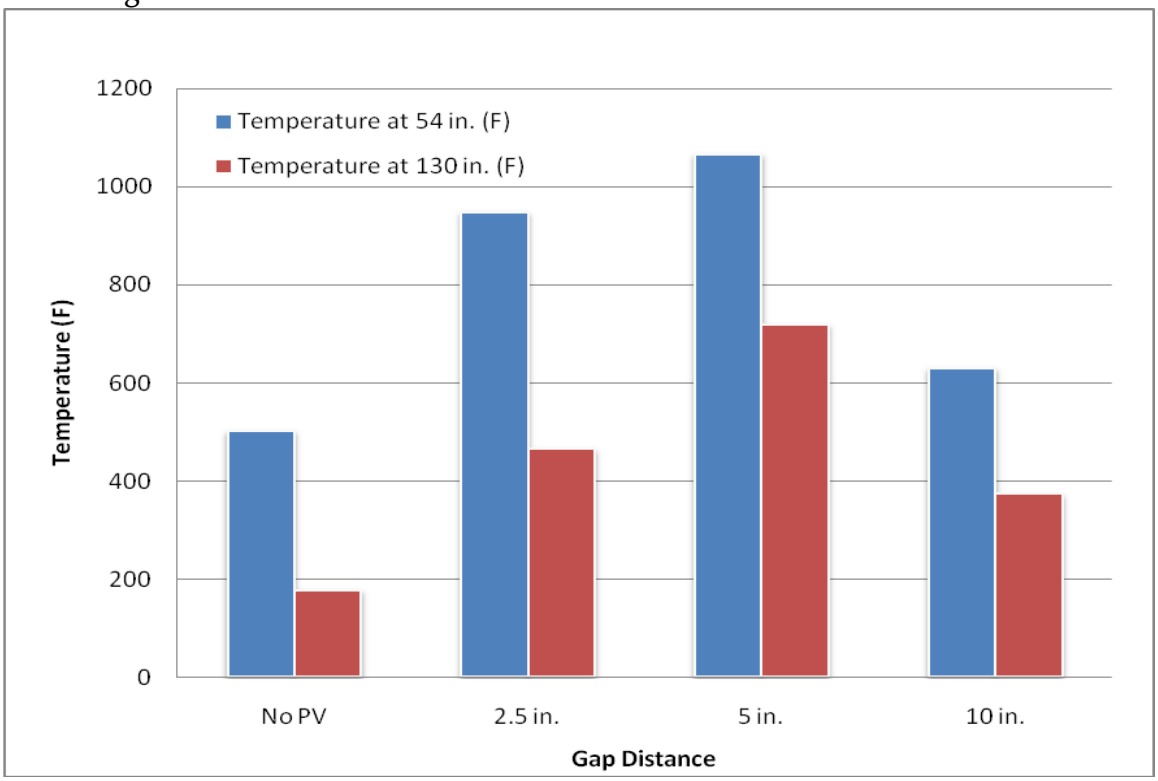

Figure 60 -Temperature of Roof with PV Module Mounted at heights of 2.5", 5", and 10" and With No Module

- The presence of a rack mounted PV module on a roof has an adverse effect on the fire performance of the roof regardless of the fire rating of the roof or the Class rating of the PV panel based on Spread of Flame test method described in UL 790 (UL 1703).

- The extent of the degradation on fire performance with respect to flame spread of a roof depends upon PV installation parameters such as setback distance and gap between roof and PV module.

- The presence of a rack mounted PV module on a roof could adversely affect the fire performance of the roof when subjected to burning brands placed on the roof based on the Burning Brand test method described in UL 790.

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Effect of Rack Mounted Photovoltaic Modules on the Flammability of Roofing Assemblies – Demonstration of Mitigation Concepts

Project Number: 08CA39594, 09CA40917
File Number: IN15911, R26475
Date: September 30, 2009
Revised: February 10, 2010

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ACKNOWLEDGMENTS

The authors would like to acknowledge the following individuals for their contributions including development of design of experiments, suggestions of mitigation techniques, guidance and support for this project:

Bill Brooks of Brooks Engineering
Larry Sherwood of Sherwood Associates
Kevin Lynn of the Department of Energy (DOE)
Andy Rosenthal of New Mexico State University

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EXECUTIVE SUMMARY

An analysis of the data generated by the experiments carried out in a previous study for Solar ABCs pointed to the following key findings:

- The presence of a rack mounted PV module on a roof has an adverse effect on the fire performance of the roof regardless of the fire rating of the roof or the Class rating of the PV panel based on Spread of Flame test method described in UL 790 (UL 1703).
- The extent of the degradation on fire performance of a roof depends upon PV installation parameters such as setback distance and gap between roof and PV module.
- The presence of a rack mounted PV module on a roof could adversely affect the fire performance of the roof when subjected to burning brands placed on the roof based on the Burning Brand test method described in UL 790.

In this investigation, additional experiments were conducted at the request of Solar ABC's to examine the efficacy of some simple mitigation concepts.

FIRE HAZARD MITIGATION – SPREAD OF FLAME

Based upon the analysis of results from previous testing, several simple design concepts were devised to assess their effectiveness in improving the fire performance of the roof systems (roof and rack mounted elevated PV module). These included (i) use of flashing at the leading edge of the roof with control of separation between roof and flashing, and (ii) use of noncombustible back sheet. The results of the mitigation tests are presented in Table E1.

Results showed the limited success of three different mitigation strategies using setback, angled flashing and a screen.

- Using only setback as a mitigation strategy, a 36 in setback did not demonstrate compliance to the requirements of Class A for the single test run.

- An angled flashing only demonstrated compliance when combined with a 36 in. setback to the requirements of Class A for the single test run.

- The 24 and 36 in setback experiments with small sized opening screens were investigated and neither demonstrated compliance to the requirements of Class A.

- A vertical flashing (continuous from roofing surface to PV top surface) demonstrated compliance to the requirements of Class A with setbacks of 0, 3 and 12 inches.

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Table E1 – Results from Selected Mitigation Techniques

Gap (in)	Setback (in)	Roof Rating	PV Rating	Mitigation	Fire Performance
5	24	Class A	Class C	Small opening screen	Not compliant to Class A
5	36	Class A	Class C	Small opening screen	Not compliant to Class A
5	36	Class A	Class C	Angled flashing with 1 in separation	Compliant to Class A
5	24	Class A	Class C	Angled flashing with 1 in separation	Not compliant to Class A
5	36	Class A	Class C	Set back only	Not compliant to Class A
5	0	Class A	Class C	Vertical flashing with 0 in separation	Compliant to Class A
5	3	Class A	Class C	Vertical flashing with 0 in separation	Compliant to Class A
5	12	Class A	Class C	Vertical flashing with 0 in separation	Compliant to Class A

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TABLE OF CONTENTS

DISCLAIMER 2
ACKNOWLEDGMENTS 3
EXECUTIVE SUMMARY 4
Fire Hazard Mitigation – Spread of Flame 4
PROJECT BACKGROUND 7
NEED FOR RESEARCH 7
RESEARCH INVESTIGATION 8
RESEARCH OBJECTIVES 8
Objective 8
MITIGATION EXPERIMENTS – VERTICAL FLASHING AND FIRE BARRIER 8
Results 8
Analysis 17
MITIGATION EXPERIMENTS – SET BACK, SCREENS AND ANGLED FLASHING 18
Objective 18
Experimental Parameters 18
Mitigation Concepts 18
Results 19
Analysis 22
SUMMARY AND RECOMMENDATIONS 23
SUMMARY OF FINDINGS 23

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PROJECT BACKGROUND

This research project was supported by the Department of Energy (DOE) under award number DE-FC36-07GO17034. The lead for this project was New Mexico State University, Las Cruces, NM. UL was a subcontracted partner under this initiative.

NEED FOR RESEARCH

An analysis of the data generated by experiments carried out in a previous study resulted in the following key findings:

- The presence of a rack mounted PV module on a roof has an adverse effect on the fire performance of the roof regardless of the fire rating of the roof or the Class rating of the PV panel based on Spread of Flame test method described in UL 790 (UL 1703).
- The extent of the degradation on fire performance of a roof depends upon PV installation parameters such as setback distance and gap between roof and PV module.
- The presence of a rack mounted PV module on a roof could adversely affect the fire performance of the roof when subjected to burning brands placed on the roof based on the Burning Brand test method described in UL 790.

Based on these findings a need for simple mitigation strategies that do not affect other roof performance criteria was identified. Demonstration of potential techniques were required to be examined and results in improving fire performance of the roof documented.

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RESEARCH INVESTIGATION

RESEARCH OBJECTIVES

The objective of this research project was to demonstrate various potential mitigation techniques to improve the flammability of for elevated PV modules on roofs

To meet these objectives, a series of experiments were conducted to demonstrate the effectiveness of possible mitigation techniques.

OBJECTIVE

The objective of this project was to conduct experiments to determine the effect of potential simple mitigation methods on a variety of PV module/roof combinations to demonstrate if the flammability of a roof system/PV module assembly can be improved.

MITIGATION EXPERIMENTS – VERTICAL FLASHING AND FIRE BARRIER

Experiments were conducted using the Spread of Flame as specified in UL 790 and UL 1703. No Burning Brand tests were conducted for this research study. For this set of tests, the roofing material, the fire rating of the PV module, the mitigation concept, and the setback distance were adjusted. The specific mitigation concepts examined included noncombustible flashing at the leading edge of the roof with variable opening size (between flashing and PV module) and a commercial fire barrier sheet applied to the back plane of the PV module.

RESULTS

Test observations are summarized in Table 1. Initial designs of a fire stop which was terminated above the roof providing an opening for roof water shedding and ventilation of the back of the PV module. The opening size was based on the initial tests from the previous PV module / roofing flammability project.

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Table 1 Test Results for Mitigation Tests

Assembly ID	Gap (in)	Setback (in)	Roof Rating	PV Rating	Flame Spread Data		Comments
					Distance (feet)	Time (Min:Sec)	
15	5	0	Noncombustible	C	8	2:35	Noncombustible flashing, 2" vertical gap
16	5	0	Noncombustible	C	8	3:00	Noncombustible flashing, 1" vertical gap
17	5	0	Noncombustible	C	0		1/4" noncombustible module applied to back plane of PV module
18	5	0	Noncombustible	C	6	5:26	Commercial fire barrier sheet applied to back plane of PV module
19	5	0	Noncombustible	A	8	5:47	
20	5	0	A - 3 Tab Shingle	C	0		7 " (height) noncombustible flashing, PV module at 0" setback
21	5	3	A - 3 Tab Shingle	C	0		7 " (height) noncombustible, PV module at 3" setback
23	5	12	A - 3 Tab Shingle	C	0		7" (height) noncombustible flashing, PV module at 12" setback

Visual results are provided in the photographs as shown in Figure 1 through Figure 15.

Figure 1 Photograph of noncombustible roof with Class C PV and modified vertical noncombustible flashing with 2” gap between bottom of flashing and roof surface

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Figure 2 Photograph of Spread of Flame Test for Setup described in Figure 1.

Figure 3 Photograph of noncombustible roof with Class C PV and modified vertical noncombustible flashing with 1" gap between bottom of flashing and roof surface.

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Figure 4 Photograph of Spread of Flame Test for Setup described in Figure 3.

Figure 5 Photograph of noncombustible roof with Class C PV modified with a noncombustible 1/4" board mounted directly to the bottom of the module

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Figure 6 Spread of Flame Test for Setup in Figure 5.

Figure 7 Photograph after the Spread of Flame test for noncombustible roof (right) and Class C PV (left) modified with noncombustible ¼" board mounted directly to the back of the PV

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Figure 8 Photograph of Class C PV with commercially available fire barrier sheet mounted directly to the bottom of the module

Figure 9 Spread of Flame Test for noncombustible roof with PV noted in Figure 8.

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Figure 10 Photograph of Class C PV with commercially available fire barrier sheet mounted directly to the bottom of the module after the Spread of Flame test

Figure 11 Setup for Class A Shingle (3 tab) roof with Class C PV modified with noncombustible flashing connecting leading edges of PV and roof

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Figure 12 Spread of Flame test for setup shown in Figure 11.

Figure 13 Setup for Class A roof with a Class C PV modified with noncombustible flashing with a 0" vertical gap and the module's leading edge 3" from the flashing

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Figure 14 Spread of Flame Test for Setup shown in Figure 13

Figure 15 Setup for Class A roof with Class C PV modified with noncombustible flashing with 0" vertical gap and 12" distance from module leading edge

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ANALYSIS

Mitigation solutions examined in this portion of the project were split in limiting flame propagation < 6 ft during the flame-spread test. Although initial fire stop flashing designs incorporated an opening size based on positive results from a previous study, using simulated PV panel, that indicated a significant decrease in temperature and heat flux, the positive performance was not duplicated with experiments using combustible PV panels and roofing materials.

Experiments which incorporated a noncombustible vertical flashing that provided either a 1 in. or 2 in. opening above the roof allowed sufficient energy to ignite the PV back plane and roofing surface. Once ignited, flame propagation exceeded the length of the deck (> 8 ft.) thus not in compliance of the requirements for Class A (< 6 ft.). A continuous noncombustible vertical flashing attached directly to the leading edge of the PV module and extending down to the roof surface (no opening) was successful in prevented the ignition flame entering the gap between the PV module and the roof surface. Flame propagation for this experiment is reported as 0 ft. Experiments incorporating the same noncombustible fire block flashing but with the PV module spaced 3 in and 12 in. away from the flashing were also successful in preventing ignition of the underside of the PV module or the roof surface. Flame propagation for both of these experiments is reported as 0 ft. Two experiments which incorporated protection fastened directly to the back of the PV module were also successful in limiting flame propagation. A ¼ in. noncombustible rigid board demonstrated flame propagation of 0 ft. A commercially available fire barrier sheet material limited flame propagation to 6 ft, which is at the threshold of the Class A requirement.

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MITIGATION EXPERIMENTS – SET BACK, SCREENS AND ANGLED FLASHING

OBJECTIVE

The objective of this task was to conduct experiments to determine the effect of additional potential mitigation methods to demonstrate if the flammability of a Class A roof system / PV module assembly is improved. Since PV modules require airflow on underside to enable more effective heat transfer from the modules, methods that were expected to improve air movement, were considered.

EXPERIMENTAL PARAMETERS

Experiments were conducted using the Spread of Flame as specified in UL 790 and UL 1703. The experiments conducted were consistent with those of previous work with the exception of the mitigation technique, which included:

- *PV modules were set back from the edge of the roof 12, 24 and 36 inches*
- *An angled flashing mounted to the leading edge of the PV module*
- *Screening mounted to the leading edge of the PV module*

Initials experiments were conducted using a noncombustible PV module surrogate mounted over a noncombustible roof deck while altering the setback distance and the mitigation concept. These tests were followed up with a series of tests with Class A roofing materials and Class C PV module while altering setback distance and mitigation concept. For these tests, visual observations of flame extension beyond the barrier were used to determine the efficacy of the technique.

MITIGATION CONCEPTS

Setback

For the experiments, which explored setback as a potential mitigation technique, the simulated PV module was positioned 0, 12, 24 and 36 in back from the leading edge of the roof deck.

Screens

Two metal screen types were evaluated. One was an expanded metal with diagonal openings measuring approximately ½ in by ¼ in. The second screen was typical insect screen material with 18 openings per inch. Photographs of the screening material are shown in Figure 16.

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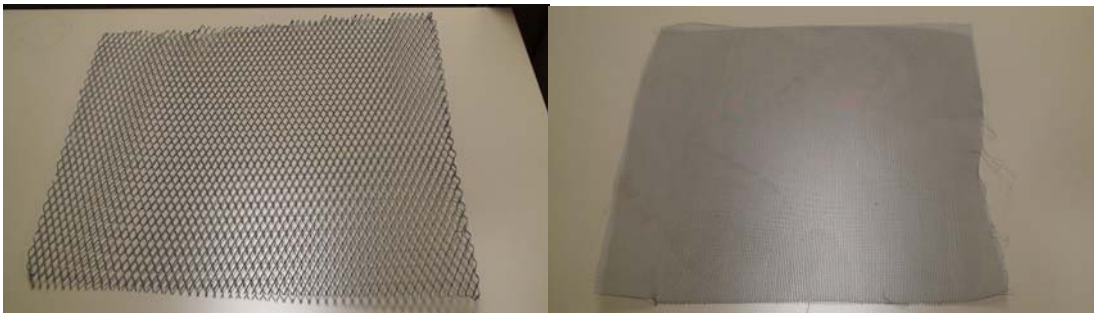

Figure 16 Photograph of large opening (left) and small opening (right) screen materials

Angled Flashing

An angled flashing was constructed using a ½ in noncombustible board. The flashing was attached to the leading edge of the PV module and positioned at 45° and 1 in above the surface of the roof deck.

RESULTS

Visual results are provided in the photographs Figure 17 through Figure 20 and with test observations summarized in Table 2 and Table 3.

Figure 17 Photograph of noncombustible roof with noncombustible PV surrogate modified with a large opening screen flashing

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Figure 18 Photograph of Spread of Flame Test showing flame extension through the large opening screen flashing.

Figure 19 Photograph of noncombustible roof with noncombustible PV surrogate modified with a small opening screen flashing

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Figure 20 Photograph of noncombustible roof with noncombustible PV surrogate modified with a noncombustible angled flashing

Table 2 Results of Mitigation on Spread of Flame for Noncombustible Roof/PV Module

Assembly ID	Gap (in)	Setback (in)	Roof Rating	PV Rating	Mitigation Concept	Flame Extend Beyond Barrier
5	5	0	Noncombustible	Noncombustible	Small opening screen	Yes
9	5	0	Noncombustible	Noncombustible	Large opening screen	Yes
6	5	12	Noncombustible	Noncombustible	Small opening screen	Yes
7	5	24	Noncombustible	Noncombustible	Small opening screen	Yes
8	5	36	Noncombustible	Noncombustible	Small opening screen	No
4	5	36	Noncombustible	Noncombustible	Angled flashing	No
3	5	24	Noncombustible	Noncombustible	Angled flashing	Intermittent
2	5	12	Noncombustible	Noncombustible	Angled flashing	Yes

Table 3 Results of Mitigation on Spread of Flame for Combustible Roof/PV Module

Assembly ID	Gap (in)	Setback (in)	Roof Rating	PV Rating	Mitigation Concept	Flame Spread Data	
						Distance (feet)	Time (Min:Sec)
10	5	24	Class A	Class C	Small opening screen	8	4:08
11	5	36	Class A	Class C	Small opening screen	8	9:46
12	5	36	Class A	Class C	Angled flashing	3.5	8:58
13	5	24	Class A	Class C	Angled flashing	8	4:39
14	5	36	Class A	Class C	Set back only	8	6:19

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ANALYSIS

Mitigation solutions examined in this project were limited in protection of the elevated PV module.

Experiments which incorporated a noncombustible roof / PV module modified with a screen indicated that a 36 in. setback was required to prevent the ignition source flames from extending to the underside of the module. In the Class C roof / non combustible PV module experiment modified with a small screen and 24 in setback, the fire propagated beyond 6 ½ ft (Class A criteria) at 4 min and 36 sec and reached the end of the 8 ft deck at 4 min and 39 sec. An increase in the setback to 26 in slightly improved the performance, however flames reached 2-½ ft at 6 min and 9 sec. The small opening screen did not result in meeting the Class A fire performance criteria.

Experiments which incorporated a noncombustible roof / PV module modified with an angled noncombustible flashing attached to the leading edge of the module and elevated 1 in above the roof deck was similar in performance. At 36 in. setback, ignition source flames did not extend to the underside of the PV module. At a 24 in. setback, ignition source flames extended up along the deck and under the PV module intermittently. At 12 in. setback, flames were continuous. In the Class C roof / non combustible PV module experiment modified with the angled flashing, the 24 in setback was noncompliant, but the 36 in. setback was compliant to Class A flame spread criteria

Experiments which incorporated only a setback (36 in) as a mitigation technique were not compliant to Class A flame spread criteria.

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SUMMARY AND RECOMMENDATIONS

SUMMARY OF FINDINGS

An analysis of the data generated by the experiments carried out in this study point to the following key findings. Simple mitigation strategies that do not affect other roof performance criteria were examined and found to produce mixed results in improving fire performance of the roof. Flashing techniques demonstrated the most potential in minimizing flame spread:

- Vertical Flashing – Vertical continuous (to roof surface) metal flashing mounted to the leading edge of the PV module was successful in blocking flames. Vertical flashing installed with gaps (to the roof surface) were not successful. Continuous metal flashings mounted independent of the PV module as a fire block with set back distances of 3 in and 12 in were successful.
- Fire Barriers – A rigid board mounted directly to the back of the module limited flame extension. A thin sheet mounted directly to the back of the module limited flame was nominally successful.
- Setback – Experiments conducted with only setback as a mitigation technique were not successful.
- Angled Flashing with setback – Angled flashings mounted to the leading edge of the PV module and installed with a 1 in. gap (to the roof surface) were not successful at setback distances of 12 and 24 inches. A 36 in setback was successful with an angled flashing.
- Screen – Experiments conducted to demonstrate the effectiveness of screens to block the entrance of the ignition source flames to limit the impingement on the underside of the elevated PV module and the exposed surface of the roof were not successful.

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Validation of 42” PV Module Setback on Low Slope Roof Experiments
Project 7

Project Number: – 11CA43479
File Number: IN15911
Date: November 30, 2012
Revised: December 12, 2012

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Acknowledgments

The authors would like to acknowledge the following individuals / organizations for their contributions including guidance and support for this project:

Bill Brooks of Brooks Engineering
Larry Sherwood of Sherwood Associates
Joe Cain of Solar City
Andy Rosenthal of New Mexico State University

1. TABLE OF CONTENTS

Acknowledgments 3
Introduction 5
Samples 6
Experiments 7
Low Slope Results 7
Summary and Recommendations 11
Summary of Findings 11
Recommendations 12

Introduction

The research described herein expands on previous work conducted over multiple phases of a broader project[1,2,3,4,5] to determine the effect of rack mounted photovoltaic (PV) modules on the fire rating of roof assemblies. In general, the experiments demonstrated that the flame spread ratings of the roof are not maintained when PV modules are installed elevated above the roof. An initial study measured the surface temperature and incident heat flux of a noncombustible room with a noncombustible PV module surrogate installed at 10, 5 and 2.5 inches above the roof. An analysis of the data indicated the 5 inch gap height to be the most critical of the three that were evaluated in terms of increased radiant flux and roof surface temperature. All three gap configurations increased the surface temperature and heat flux on the roof assembly higher than those measured in the absence of the PV module.

A subsequent second project further investigated rack mounted PV modules on roof decks to determine (1) the effect of PV modules mounted at angles (positive and negative) to steep and low sloped roofs, (2) the impact of PV modules mounted at zero clearance to the roof surface and with the ignition source directed in the plane of the roof or the plane of the PV surface, and (3) the heat release rate and transfer to roof surface of Class A, B, C brands and common materials such as leaf debris and excelsior (wood wool).

A third project investigated the critical flux for ignition of roofing and PV products. While the individual values varied, most were within the range of the flux values measured on the roof in the original experiments without the PV module in place.

Then a fourth project was undertaken to validate the performance of two approaches thought to mitigate the effect of rack mounted PV modules on the fire ratings of roofs - a minimum separation gap and a sheet metal flashing to block the passage of flames between the PV module and the roof assembly. A continuous flashing was determined to effectively block the passage of flame along the roof under a PV module. A minimum distance of 12 inches above a steep slope (shingled) roof was determined to sufficiently separate the two surfaces to maintain the roof's original fire rating. Experiments up to a height of 24 inches above a low slope roof resulted in flame spread in excess of the performance criteria for a Class A roof.

A fifth Project 5 described a series of experiments to investigate a modification of the current UL 1703 spread of flame test to (1) expose a PV module to flames originating from the UL790 (ASTM E108) ignition source, (2) allow those flames to generate on a representative roof section, and (3) observe the propagation of the flames underneath the candidate PV module being tested. Previous research within Project 1 had been conducted with the PV module

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[1] Effect of Rack Mounted Photovoltaic Modules on the Flammability of Roofing Assemblies, Dated September 30, 2009, Revised March 5, 2010,

[2] Effect of Rack Mounted Photovoltaic Modules on the Fire Classification Rating of Roofing Assemblies, Dated January 30, 2012

[3] Characterization of Photovoltaic Materials – Critical Flux for Ignition / Propagation Phase 3 Dated January 16, 2012,

[4] Determination of Effectiveness of Minimum Gap and Flashing for Rack Mounted Photovoltaic Modules. Phase 4 Dated March 29, 2012

[5] Considerations of Module Position on Roof Deck During Spread of Flame Tests, Phase 5, Dated July 24, 2012

installed in a position where both the roof and the module were subjected to the ignition source with zero set back and with only modest set back distances (24 inches or less). The repositioning of the PV module was conducted to investigate an application of first item (roof) / second item (module) ignition sequence. This concept was investigated to refine the understanding of the effect of a rack mounted PV array on the fire rating of a Class A roof. Experiments were conducted on low and steep slope roofs.

In addition to the work described above, three additional projects resulted from discussions with PV and roofing industry stakeholders. These projects include:

- Project # 6 – A series of experiments to demonstrate generic installation details of PV and roofing systems. If compliant, these details can be documented and used by industry without the need for further evaluation. As of the date of this report, work under Project 6 had not begun.
- Project # 7 – As described in this report, this series of experiments was conducted to generate data in support of proposed changes to UL 1703, specifically, 42 inch setback of the PV module on low slope roofs.
- Project # 8 – Development of a burner designed to represent the flame spread along the roof surface. This burner could potentially replace the standard roof configurations described in the UL 1703 proposal improving the test protocol by eliminating variation of the burning roof deck. . As of the date of this report, work under Project 8 had not begun.

The results of this investigation (# 7) could be used to:

1. Validate performance of low slope roof test parameters as contained in a draft of a revised test method for consideration by the UL 1703 Standards Technical Panel (STP), and
2. Provide quantitative data to support the proposed standard revisions, specifically, 42 inch setback of the PV module on low slope roofs.

Samples

Commercially available PV modules and roofing product samples were acquired either through industry donation or purchased from local retailers. The PV modules were a Class C fire rated metal framed glass on polymer design. A surrogate representation of a PV module was simulated using a noncombustible sheet for some experiments.

UL 790/ASTM E 108 Class A rated roof deck assemblies consisted of:

- 60 mil LSFR EPDM (low slope, fire retardant, ethylene propylene diene monomer) over
- 4 inch thick polyisocyanurate insulation board mechanically fastened to a
- combustible deck.

Experiments

Fire performance of the PV modules on roof deck assemblies was investigated by Spread of Flame tests as being considered for proposal to the UL 1703 STP.

For these experiments, the objective was to conduct the experiments with the module subjected to a thermal exposure resulting primarily from the burning roof. This was accomplished by positioning the module at a distance beyond exposure of the test fixture ignition source, but within range of the flame progression along the surface of the roof. This setback distance was 42 in. with the PV module elevated 5 in. above the roof surface. A baseline experiment was conducted to establish the flame propagation along the roof's surface in the absence of a PV module.

Low Slope Results

Three experiments were conducted with the standard low slope roof as described in the current UL1703 proposal being considered by the UL1703 Standards Technical Panel. Maximum flame spread distances and the corresponding time at which they occurred for the various low slope roof assembly experiments are listed in Table 1.

The baseline experiment without a PV module present demonstrated a maximum flame spread distance along the roof of 5 ft., which is Class A compliant.

All of the PV / roof experiments were conducted with aluminum framed glass on polymer PV modules installed at a gap height of 5 in., an offset of 42 in and parallel to the roof (0° inclination). During two of the three experiments, the flame spread extended to a maximum of 3.5 ft. (Class A, compliant). A third roof / PV experiment was conducted resulting in a flame spread of 8 ft (Class A nonccompliant) where flame spread across the roof surface with both the module and the roof fully involved with flames extending beyond the deck.

Table 1 - Summary of Repositioning Experiments – Low Slope

						Roof														
			Gap		Module		Time of Roof Flame Spread													
System		System	Height	Slope	Offset	Ignition	0.5'	1.0'	2.0'	2.5'	3.0'	3.5'	4.0'	4.5'	5.0'	5.5'	6.0'	6.5'	7.0'	Class A
#	Slope	Notes	(in)	(in/in)	(in)	(sec)	(m:s)	(m:s)	(m:s)	(m:s)	(m:s)	(m:s)	(m:s)							Compliant
Experiments conducted November 5 2012																				
1	Low	PV	5	0.5/12	42	0:51	0:51	1:40	2:40	2:52	3:19	4:50								Yes
2	Low	PV	5	0.5/12	42	0:56	0:56	1:59	2:38	3:00	3:35	5:01								Yes
3	Low	Baseline	N/A	0.5/12	N/A	0:53	0:53	1:49	2:27	NR	3:03	3:26	3:54	4:44	7:22					Yes
4	Low	PV	5	0.5/12	42	0:42	0:42	1:34	2:06	NR	2:31	2:57	3:28	NR	4:17	4:28	4:37	4:42	4:49	No
NA = Not Applicable																				
NR = Not Recorded																				

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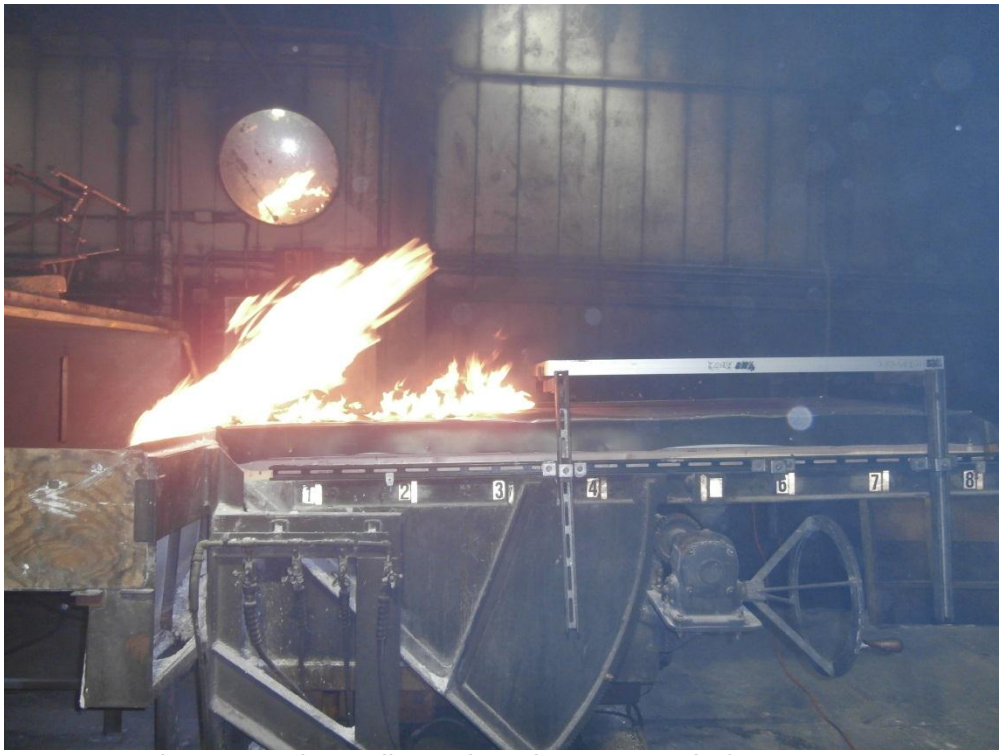

Figure 1 – Figure Illustrating Flame Spread of System 1

Figure 2 – Figure Illustrating Flame Spread of System 2

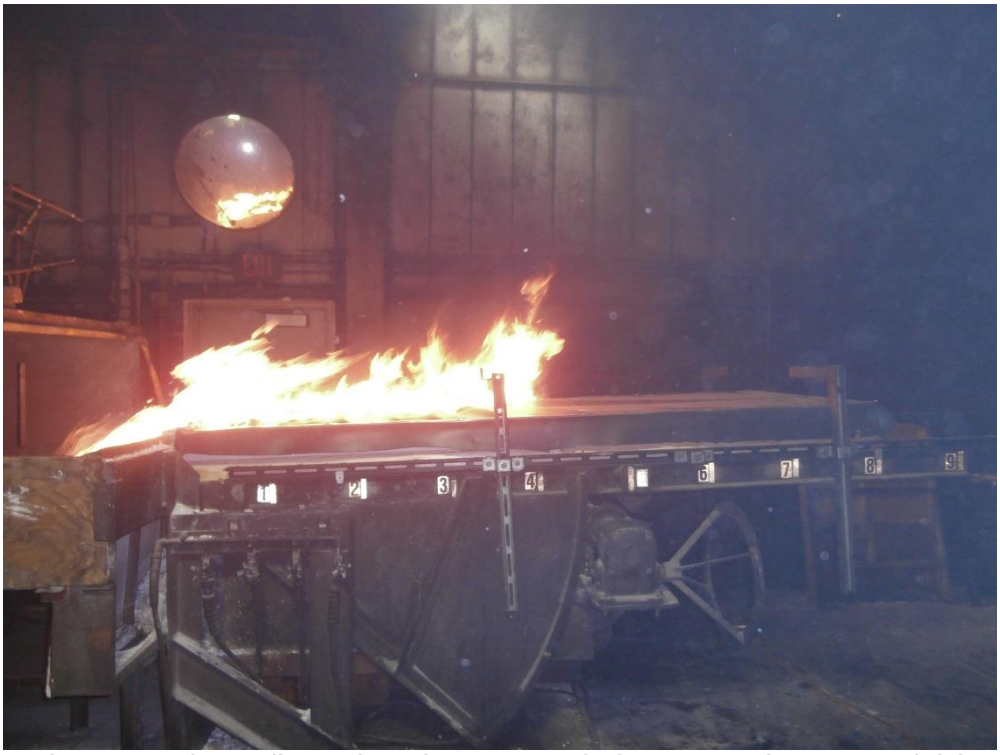

Figure 3 – Figure Illustrating Flame Spread of System 3 (No PV Module)

Figure 4 – Figure Illustrating Ignition of the Module and Roof of System 4

Summary and Recommendations

Summary of Findings

Although the experiments conducted for this report are not exhaustive, an analysis of the generated data point to the following key findings:

- The low slope roof baseline (no PV) experiment exhibited a flame spread of 60 inches. This Class A compliant performance is consistent with previous flame spread experiments.
- Two of the PV / roof assembly experiments exhibited a flame spread of 42" (Class A compliant)
- One experiment conducted on the same assembly exhibited a flame spread of 96" (Class A noncompliant).
- This inconsistency can be compared to the critical flux determinations of roofing materials as investigated in the third project and reported in "Characterization of Photovoltaic Materials – Critical Flux for Ignition/Propagation, January 16, 2012." The Critical heat flux for ignition is the lowest thermal load per unit area capable of initiating a combustion reaction on a given material (either flame or smolder ignition). In these experiments, the thermal conditions of the roof / PV assembly configuration are such that fire propagation along the roof and up under the module are at a critical stage.
- Observations of the ignition source flame and the flame emanating from the roof surface indicated the following influencing factors for the different experimental results:
    - During all of the experiments, the ignition source did not impinge directly onto either the roof surface or the PV module. The roof surface was ignited by radiant heat from the ignition flame. Upon ignition, flames propagated along the roof surface.
    - During two of the experiments, flames advanced along the roof up to the front of the module (42"), but did not advance further. The flame front was observed to be leaning in the direction of the forward end of the roof deck, opposite of the 12 mph airflow. This observation indicates that the diffusion flame at the roof / PV module interface was drawing combustion air from under the PV module.
    - During the experiment that resulted in a flame spread of 96", the flame front demonstrated similar physiognomies as the previous experiments - advancing along the roof up to the roof / module interface. However, during this experiment, the flame front advancement paused temporarily at 42" until ignition of the module as indicated by flames observed along the leading edge of the PV module frame. The flames grew in intensity and extended under the module igniting the module substrate. Once this occurred, flames propagated along the module substrate and roof surfaces. This combination flame front grew quickly extending beyond the roof deck at which time the experiment was terminated by extinguishing the fire.

Recommendations

These experiments support the recommendations as previously suggested in Project 5, specifically regarding 42 inch between the edge of the flame test apparatus and the edge of the PV mounting system for low sloped roofs.

As previously noted in the report "Considerations of Module Position on Roof Deck During Spread of Flame Tests Phase 5":

> "Based on the research study findings, the repositioning approach of examining the first item ignited (roof) and then the second item ignited (PV), was a viable method for assessing the performance of a roof / PV combination. It was observed that this method was of such severity that currently commercially available PV Class C modules would likely have to be modified, or the installation details specified, in order to yield compliant results for both low and steep slope tests. It is important to note that the results of tests with the PVs present were fairly consistent with tests using a surrogate noncombustible PV.

Consequently, the Research Team as well as a focus group present to observe some of these tests supported the following recommendations and suggestions to propose revisions to UL 1703 as follows:

Spread-Of-Flame Tests to be conducted:

- Individually with the module mounted on a noncombustible deck and oriented such that the ignition flame is directed on the top surface of the module or panel.
- With the module installed on a steep slope and low slope roofs as an assembly and oriented such that the ignition flame is directed into the interstitial space below the module and above the roof. The module or panel installation shall be installed:
    a. with a 36 inch (0.91 m) between the edge of the flame test apparatus and the edge of the PV mounting system for steep sloped roofs,
    b. with 42 inch (1.07 m) between the edge of the flame test apparatus and the edge of the PV mounting system for low sloped roofs."

Collectively, the results of the experiments described in this report and those reported in the previous report "Considerations of Module Position on Roof Deck During Spread of Flame Tests Phase 5" validate a 42" offset of a PV module over low slope roofs as a critical point which differentiates performance of PV module design and installation details.

Validation of Roof Configuration 2 Experiments
Project 9

Project Number: 13CA06530
File Number: SV19516
Date: February 12, 2013

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Acknowledgments

The authors would like to acknowledge the following individuals / organizations for their contributions including guidance and support for this project:

Bill Brooks of Brooks Engineering
Larry Sherwood of Sherwood Associates
Joe Cain of Solar City
Nathan Schweller of Sun Power Corporation

1. TABLE OF CONTENTS

Acknowledgments 3
Introduction 5
Samples 10
Experiments 11
Scoping Tests 11
Baseline Tests 11
Fire Performance Tests with PV Modules 11
Summary and Recommendations 18
Summary of Findings 18
Recommendations 19

Introduction

The research described herein expands on previous work conducted over multiple phases of a broader project[1,2,3,4,5,6] to determine the effect of rack mounted photovoltaic (PV) modules on the fire rating of roof assemblies. In general, the experiments demonstrated that the spread of flame ratings of the roof are not maintained when PV modules are installed elevated above the roof. An initial study measured the surface temperature and incident heat flux of a noncombustible room with a noncombustible PV module surrogate installed at 10, 5 and 2.5 inches above the roof. An analysis of the data indicated the 5 inch gap height to be the most critical of the three that were evaluated in terms of increased radiant flux and roof surface temperature. All three gap configurations increased the surface temperature and heat flux on the roof assembly higher than those measured in the absence of the PV module. Subsequent investigations were conducted to develop data for mitigation strategies. These are summarized in Table 1.

Table 1 – Research Summary

Project Number	Discussion
08CA39594, 09CA40917	**Effect of Rack Mounted Photovoltaic Modules on the Fire Classification Rating of Roofing Assemblies September 30, 2009, Revised November 30, 2010** Investigated rack mounted PV modules on roof decks to determine: (1) the effect of PV modules mounted at angles (positive and negative) to steep and low sloped roofs; (2) the impact of PV modules mounted at zero clearance to the roof surface and with the ignition source directed in the plane of the roof or the plane of the PV surface: and (3) the heat release rate and transfer to roof surface of Class A, B, C brands and common materials such as leaf debris and excelsior (wood wool). **Key Findings:** Based on the findings in this report, the installation of a rack mounted PV module on a roof has an impact on the fire resistance ratings of the roof system, regardless of the fire rating of the roof or PV module. For instance, the increase in distance (setback) between the leading edge of the roof and the PV module lessens the chances that the flame will be captured in the gap between the PV panel and roof surface that might otherwise lead to significant burning during the spread of flame test. • A surrogate rack mounted PV module parallel to the roof surface, the fire exposure from the Spread of Flame test resulted in greater temperatures on the roof surface in the area underneath the PV module. In addition, the heat

[1] Effect of Rack Mounted Photovoltaic Modules on the Flammability of Roofing Assemblies, Dated September 30, 2009, Revised March 5, 2010,
[2] Effect of Rack Mounted Photovoltaic Modules on the Fire Classification Rating of Roofing Assemblies, Dated January 30, 2012
[3] Characterization of Photovoltaic Materials – Critical Flux for Ignition / Propagation Phase 3 Dated January 16, 2012,
[4] Determination of Effectiveness of Minimum Gap and Flashing for Rack Mounted Photovoltaic Modules. Phase 4 Dated March 29, 2012
[5] Considerations of Module Position on Roof Deck During Spread of Flame Tests, Phase 5, Dated July 24, 2012
[6] Validation of 42" PV Module Setback on Low Slope Roof Experiments

Project Number	Discussion
	flux on the roof surface also increased. The magnitude of these effects was dependent on the gap size between the module and the roof, as well as the setback distance of the module from the roof leading edge. • For the parameters in this study, it was found that when the gap between the rack mounted PV module and the roof was reduced from 10 inches to 5 inches the measured surface temperatures increased5. It was observed that both the 10 inch and 5 inch gap captured all of the flames, however the smaller gap also reduced the amount of entrained air into the fire plume thus elevating the temperature of exposed surfaces. When the gap size was reduced further to the value of 2.5 inch, the measured surface temperatures did not increase but rather lowered, as the gap was sufficiently decreased to capture only a portion of the flames. • The influence of the setback of the PV module on the measured temperature and heat flux on the roof surface was highest when the PV module was in line with the leading edge (i.e., no setback distance). The measured temperatures and heat flux exposure lessened as the setback distance was extended.
08CA39594, 09CA40917	**Effect of Rack Mounted Photovoltaic Modules on the Flammability of Roofing Assemblies – Demonstration of Mitigation Concepts, Dated September 30, 2009, Revised: February 10, 2010** Investigated the efficacy of some simple mitigation concepts to minimize flame propagation under a roof mounted PV module. These included (i) use of flashing at the leading edge of the roof with control of separation between roof and flashing, and (ii) use of noncombustible back sheet. **Key Findings:** Results showed the limited success of three different mitigation strategies using setback, angled flashing and a screen. • Using only setback as a mitigation strategy, a 36 in setback did not demonstrate compliance to the requirements of Class A for the single test run. • An angled flashing only demonstrated compliance when combined with a 36 in. setback to the requirements of Class A for the single test run. • The 24 and 36 in setback experiments with small sized opening screens were investigated and neither demonstrated compliance to the requirements of Class A. • A vertical flashing (continuous from roofing surface to PV top surface) demonstrated compliance to the requirements of Class A with setbacks of 0, 3 and 12 inches.
10CA49953	**Effect of Rack Mounted Photovoltaic Modules on the Fire Classification Rating of Roofing Assemblies, Dated January 30, 2012** Investigated **Key Findings:** Based on the findings in this report, the installation of a rack mounted PV module on a roof has an impact on the fire resistance ratings of the roof system, regardless of the fire rating of the roof or PV module. For instance, the increase in distance (setback) between the leading edge of the roof and the PV module lessens the chances that the flame will be captured in the gap between the PV panel and roof surface that might otherwise lead to significant burning during the spread of flame test.
11CA43479	**Characterization of Photovoltaic Materials – Critical Flux for Ignition / Propagation. Dated January 16, 2012** Investigated the critical flux for ignition of roofing and PV products. While the

Project Number	Discussion
	individual values varied, most were within the range of the flux values measured on the roof in the original experiments without the PV module in place. **Key Findings:** The critical flux values for most of the roofing products was determined to be greater than the 15 kW/m2 exposure measured on the surface of a noncombustible deck without a PV. Exceptions being one architectural shingle, one membrane and two insulation boards with critical heat flux values of 14, 14, 13, 14 kW/m^2 respectfully. • The critical flux values for all of the roofing products was determined to be less than the 41 kW/m2 exposure measured on the surface of a noncombustible deck with a PV installed with a gap of 5” • The critical flux for ignition of low slope roof products was found to be generally consistent as were the critical flux for ignition of high slope roof products. It should be noted that the roofing products had been evaluated by UL 1703 and have attained a Class A rating either a product in the case of a shingle or as a component of a system in the case of the low slope materials (sheets, insulation, membrane). As such a degree of fire performance would be expected.
11CA43479	**Determination of Effectiveness of Minimum Gap and Flashing for Rack Mounted Photovoltaic Modules. Dated March 29, 2012** Validate the performance of two potential approaches to mitigate the effect of rack mounted PV modules on the fire ratings of roofs: (i) a minimum separation gap; and (ii) a sheet metal flashing to block the passage of flames between the PV module and the roof assembly. **Key Findings:** A continuous flashing was determined to effectively block the passage of flame along the roof under a PV module. A minimum distance of 12 inches above a steep slope (shingled) roof was determined to sufficiently separate the two surfaces to maintain the roof’s original fire rating. Experiments up to a height of 24 inches above a low slope roof resulted in spread of flame in excess of the performance criteria for a Class A roof.
11CA43479	**Considerations of Module Position on Roof Deck During Spread of Flame Tests, Dated July 24, 2012** Investigate a modification of the current UL 1703 spread of flame test to: (1) expose a PV module to flames originating from the UL790 (ASTM E108) ignition source; (2) allow those flames to generate on a representative roof section; and (3) observe the propagation of the flames underneath the candidate PV module being tested. Previous research within Project 1 had been conducted with the PV module installed in a position where both the roof and the module were subjected to the ignition source with zero set back and with only modest set back distances (24 inches or less). The repositioning of the PV module was conducted to investigate an application of first item (roof) / second item (module) ignition sequence. This concept was investigated to refine the understanding of the effect of a rack mounted PV array on the fire rating of a Class A roof. Experiments were conducted on low and steep slope roofs. **Key Findings:** Low slope: • The low slope roof baseline experiment (no PV) exhibited a flame spread of 60 inches.

Project Number	Discussion
	• Both a noncombustible representation of a PV module or a Class C PV module mounted parallel to and at an elevation of 5 inches above the roof and at offsets of 48 and 52 inches flame spreads were in excess of Class A performance requirements. • A PV module mounted at a slight inclination (10°) to and at an elevation of 5 inches above the roof and at a 48 inch offset did comply with Class A requirements. • A single experiment conducted with two modules angled to the roof (10° inclination), the first offset 24 inches and the second space 12 inches from the first did not comply with Class A requirements. • The overall results of low slope tests with the PVs present were fairly consistent with tests using a surrogate noncombustible PV . Steep slope: • The steep slope roof baseline experiments (no PV) exhibited a flame spread of 48 inches. • A noncombustible representation of a PV module mounted parallel to and at an elevation of 5 inches above the roof with an offset of 42 inches complied with Class A requirements. • Two experiments conducted with PV modules mounted parallel to and at an elevation of 5 inches above the roof with an offset of 42 inches complied with Class A requirements. • Two experiments conducted with PV modules mounted parallel to and at an elevation of 5 inches above the roof with an offset of 36 inches complied with Class A requirements. • An additional experiment was conducted with a noncombustible sheet mounted parallel to and at an elevation of 5 inches above the roof with an offset of 24 inches and did not comply with Class A requirements • The overall results of steep slope tests with the PVs present were fairly consistent with tests using a surrogate noncombustible PV .
11CA43479	**Validation of 42" PV Module Setback on Low Slope Roof Experiments Dated December 12, 2012** This series of experiments was conducted to generate data in support of proposed changes to UL 1703, specifically, 42 inch setback of the PV module on low slope roofs. **Key Findings:** The low slope roof baseline (no PV) experiment exhibited a flame spread of 60 inches. This Class A compliant performance is consistent with previous flame spread experiments. • Two of the PV / roof assembly experiments exhibited a flame spread of 42" (Class A compliant) One experiment conducted on the same assembly exhibited a flame spread of 96" (Class A noncompliant). o This inconsistency can be compared to the critical flux determinations of roofing materials as investigated in the third project and reported in "Characterization of Photovoltaic Materials – Critical Flux for Ignition/Propagation, January 16, 2012." The Critical heat flux for ignition is the lowest thermal load per unit area capable of initiating a combustion reaction on a given material (either flame or smolder ignition). In these experiments, the thermal conditions of the roof / PV assembly configuration are such that fire

Project Number	Discussion
	propagation along the roof and up under the module are at a critical stage. • Observations of the ignition source flame and the flame emanating from the roof surface indicated the following influencing factors for the different experimental results: o During all of the experiments, the ignition source did not impinge directly onto either the roof surface or the PV module. The roof surface was ignited by radiant heat from the ignition flame. Upon ignition, flames propagated along the roof surface. o During two of the experiments, flames advanced along the roof up to the front of the module (42”), but did not advance further. The flame front was observed to be leaning in the direction of the forward end of the roof deck, opposite of the 12 mph airflow. This observation indicates that the diffusion flame at the roof / PV module interface was drawing combustion air from under the PV module. o During the experiment that resulted in a flame spread of 96”, the flame front demonstrated similar physiognomies as the previous experiments - advancing along the roof up to the roof / module interface. However, during this experiment, the flame front advancement paused temporarily at 42” until ignition of the module as indicated by flames observed along the leading edge of the PV module frame. The flames grew in intensity and extended under the module igniting the module substrate. Once this occurred, flames propagated along the module substrate and roof surfaces. This combination flame front grew quickly extending beyond the roof deck at which time the experiment was terminated by extinguishing the fire.

As described in this report, this project included a series of experiments conducted to generate data on a complete PV assembly / roof configuration including rack and air deflection hardware.

The results of this investigation could be used to:

1. Validate performance of low slope roof test parameters as contained in a draft of a revised test method for consideration by the UL 1703 Standards Technical Panel (STP), and
2. Provide quantitative data to support the proposed standard revisions, specifically, a PV assembly including a module, rack and air deflection hardware mounted on a standardized roof configuration representing roofs with minimal slope.

In addition to the work described above, two additional projects resulted from discussions with PV and roofing industry stakeholders are under consideration. These projects include:

- Project # 6 – A series of experiments to demonstrate generic installation details of PV and roofing systems. If compliant, these details can be documented and used by industry without the need for further evaluation. As of the date of this report, work under Project 6 had not begun.
- Project # 8 – Development of a burner designed to represent the spread of flame along the roof surface. This burner could potentially replace the standard roof configurations described in the UL 1703 proposal improving the test protocol by eliminating variation of the burning roof deck. As of the date of this report, work under Project 8 had not begun.

Samples

Commercially available PV modules and roofing product samples were acquired either through industry donation or purchased from local retailers.

The PV modules were a Class C fire rated metal framed glass on polymer design.

UL 790/ASTM E 108 Class A rated roof deck assemblies consisted of a 60 mil LSFR EPDM (low slope, fire retardant, ethylene propylene diene monomer), and a 70 mil FR EPDM (fiber reinforced ethylene propylene diene monomer) over 4 inch thick polyisocyanurate insulation board mechanically fastened to a combustible deck.

Experiments

Fire performance of the PV modules on roof deck assemblies was investigated by Spread of Flame tests as being considered for proposal to the UL 1703 STP. In accordance with the proposed protocol, multiple experiments were conducted to represent fire approach paths from 3 directions to the array – south, north and east/west.

For these experiments, the objective was to conduct the experiments with the PV assembly (module, rack and air deflector) subjected to a thermal exposure resulting primarily from the burning roof. This was accomplished by positioning the PV assembly with an offset distance as determined by conducting 3 baseline experiments of the roof only.

Scoping Tests

Scoping tests were performed to identify a suitable candidate roofing system to use for the project investigation using UL 790 Class A flame test procedure without the PV module.

An experiment conducted with a LSFR (fire retardant) EPDM membrane roof system resulted in a flame spread distance of 90 inches, which is in excess of Class A requirement.

An experiment with FR (fiber reinforced) EPDM membrane roof system resulted in flame spread distance of 69 inches and was in compliance with the Class A criteria.

This system was selected for the rest of the experiments.

Baseline Tests

Two additional tests were conducted with FR (fiber reinforced) EPDM membrane roof system to determine the extent of flame propagation in the UL 790 flaming mode test for Class A roof systems and calculate the offset distance to be used with PV module tests. The results of three replicate tests are presented in Table 2.

Table 2 – Baseline Test Results

Test Number	Flame Spread Distance (in.)
1	69
2	60
3	54
Average	**61**

An offset distance of 49 in was calculated by subtracting 12 inches from the average flame spread distance.

This offset distance was used in the subsequent tests by locating the leading edge of the PV assembly a distance of 49 inches from the edge of the roof deck edge.

Fire Performance Tests with PV Modules

Four experiments were conducted with the standard low slope roof as described in the current UL1703 proposal being considered by the UL1703 Standards Technical Panel.

The experiments were conducted with aluminum framed glass on polymer PV modules installed on a metal frame providing a 10° inclination to the roof with the lowest portion of the module elevated above the roof ¾ in. The assembly included metal hardware at the sides and back of the module. The PV assemblies were located at a distance of 49 in. from the edge of the roof deck.

The test set-up is shown in Figure 1.

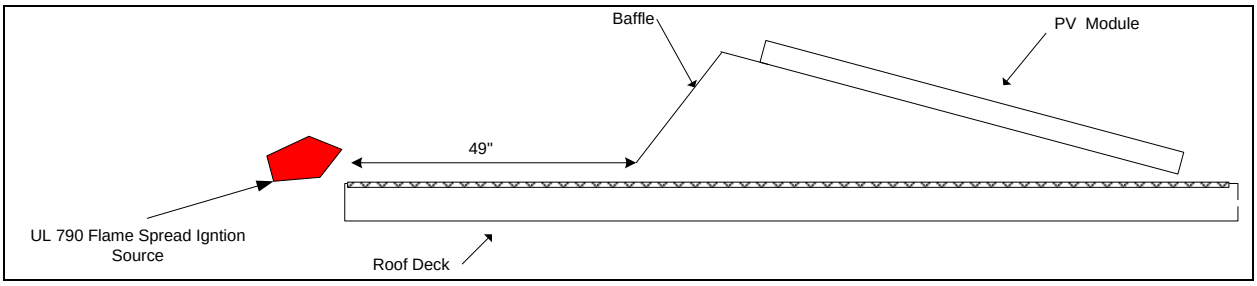

Figure 1 – Test Set-up (North Exposure Shown)

For experiments which included a PV wider than the spread of flame deck, an improvised pedestal mount was temporarily affixed to support the PV assembly. An additional south exposure experiment was conducted to determine the effect of adding an extension to the roof deck (platform) to support a PV assembly which was wider than the width of a standard wood spread of flame roof deck.

1. South Exposure PV / FR EPDM System – “Pedestal” mounting
2. North Exposure PV / FR EPDM System – “Pedestal” mounting
3. East/West PV / FR EPDM System – “Pedestal” mounting
4. South Exposure PV / FR EPDM System – “Platform” mounting

Maximum spread of flame distances and the corresponding time at which they occurred for the various low slope roof assembly experiments are listed in Table 1.

During each of the experiments, the spread of flame extended to less than 6 ft., all were Class A compliant.

Table 1 - Summary of PV / Roof Assembly Experiments

			PV		Time of Roof Flame Spread													Class A
Exp. #	EPDM Membrane	Fire Exp.	Offset (in)	Ign. (m:s)	0.5' (m:s)	1.0' (m:s)	2.0' (m:s)	3.0' (m:s)	3.5' (m:s)	4.0' (m:s)	4.5' (m:s)	5.0' (m:s)	5.5' (m:s)	5.75' (m:s)	6.0' (m:s)	6.5' (m:s)	7.0' (m:s)	7.5' (m:s)	Compliant (Y/N)
Experiments conducted January 29, 2013																			
1	LSFR	NA	NA	1:32	1:32	2:16	2:49	3:28		4:04	4:24	5:01	6:07		6:38	7:59	8:46	9:38	No
2	FR	NA	NA	0:54	0:54	1:13	2:15	3:13		3:59	4:59	6:27	8:36	9:46					Yes
3	FR	NA	NA	1:04	1:04	1:37	2:36	3:50		5:04	6:31	9:20							Yes
4	FR	NA	NA	1:06	1:06	1:50	3:04	4:30		7:50	9:31								Yes
Experiments conducted January 28, 2013																			
1	FR	South	49	1:00	1:00	1:48	2:58	4:08	4:52	6:08									Yes
2	FR	North	49	1:06	1:06	1:46	2:55	4:19	6:06	9:02									Yes
3	FR	E/W	49	1:00	1:00	1:41	2:53	4:28	5:25	7:17									Yes
4	FR	South	49	1:00	1:00	1:52	3:05	4:38	5:22	6:50									Yes

UL LLC
333 Pfingsten Road, Northbrook, IL 60062-2096 USA
T: 847.272.8800 / F: 847.272.8129 / W: UL.com

Figure 2 – Figure Illustrating Spread of flame of South Exposure PV / FR EPDM System – “Pedestal” mounting.

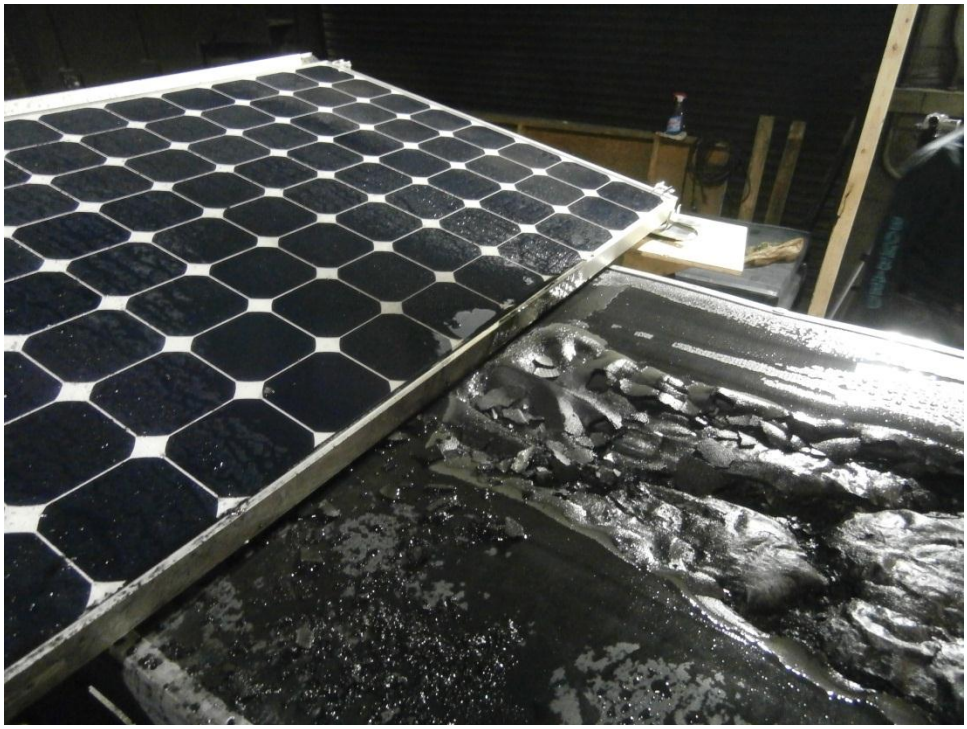

Figure 3 – Figure Illustrating Damage to the PV Module and the Roof Surface.

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Figure 3 – Figure Illustrating Spread of flame of North Exposure PV / FR EPDM System – “Pedestal” mounting.

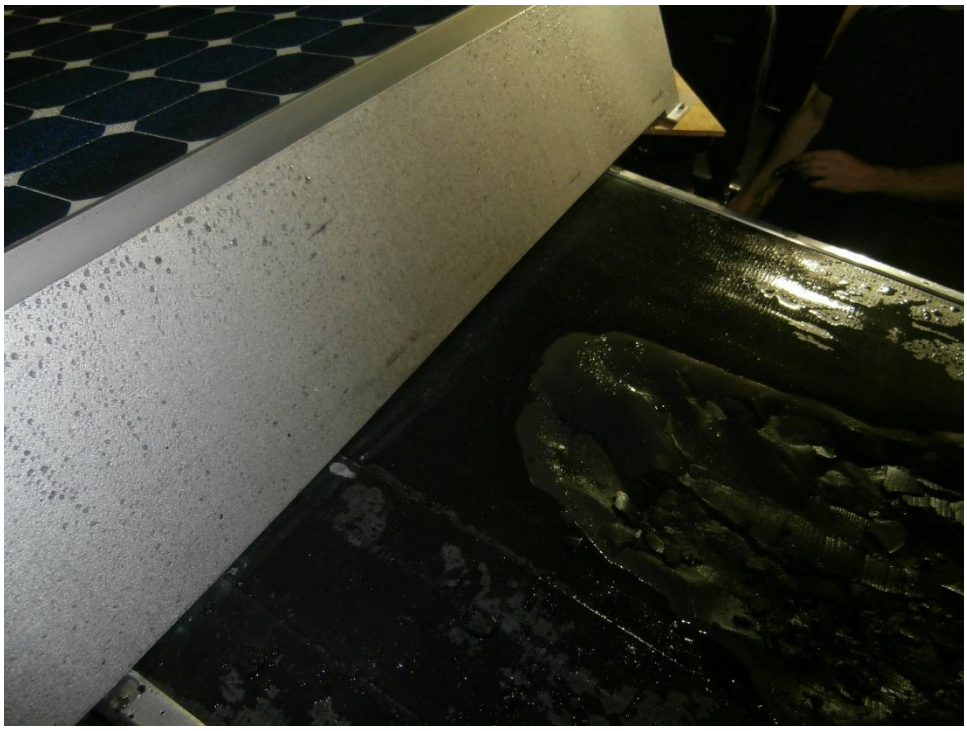

Figure 4 – Figure Illustrating Damage to Roof Surface.

Figure 5 – Figure Illustrating Spread of flame of East/West PV / FR EPDM System – “Pedestal” mounting.

Figure 6 – Figure Illustrating Damage to Roof Surface.

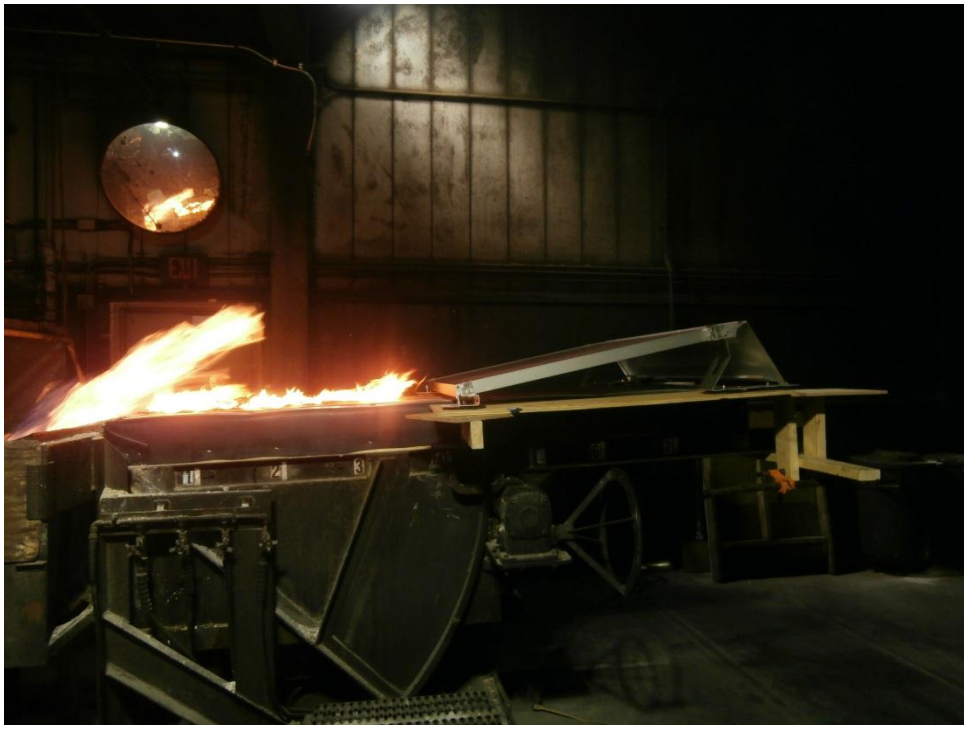

Figure 7 – Figure Illustrating Spread of Flame of South Exposure PV / FR EPDM System – “Platform” mounting.

Figure 8 – Figure Illustrating Damage to Roof Surface.

Summary and Recommendations

Summary of Findings

Although the experiments conducted for this report are not exhaustive, an analysis of the generated data point to the following key findings:

- A minimum slope roof baseline (no PV) experiment conducted with a LSFR EPDM exhibited a spread of flame of greater than 60 inches. This Class A non-conforming performance is inconsistent with previous spread of flame experiments.
- Three minimum slope roof baseline (no PV) experiments conducted with a FR EPDM exhibited a spread of flame of less than 60 inches (Class A).

These experiments indicate a benefit to developing a burner to mimic flame propagation along a roof surface which would minimize variation in PV / Roof assembly testing.

- Four PV / roof assembly experiments incorporating a commercially available rack and baffle system exhibited a spread of flame of less than 60 inches (Class A compliant)
- Observations of the ignition source flame indicated the roof surface ignited and propagated flames up to the PV / rack assembly.
    - During all of the experiments, the ignition source did not impinge directly onto either the roof surface or the PV module. The roof surface was ignited by radiant heat from the ignition flame. Upon ignition, flames propagated along the roof surface.
    - During all of the experiments, flames advanced along the roof up to the front of the inclined module (South exposure) or metal deflector (North and E/W exposures) but did not advance further.
- During the South exposure experiments, thermal damage was observed on the leading edge of the module. In previous experiments, flames and molten droplets were observed in this area along the metal frame. These flames grew in intensity and the fire progressed along the PV substrate and roof surface. In this series of experiments the PV leading edge did not exhibit flaming at the leading edge which can be attributed to the PV module design in addition to the rack and installation details. Another module design with different construction details such as frame, back sheet , encapsulant sealing materials may have exhibited different performance.

Recommendations

These experiments support the recommendations of offsetting the PV assembly at a distance determined by the flame spread of 3 roof only baseline tests as previously reported in:

- Considerations of Module Position on Roof Deck During Spread of Flame Tests, Phase 5, Dated July 24, 2012,
- Validation of 42" PV Module Setback on Low Slope Roof Experiments Dated December 12, 2012

The results of the baseline experiments described in this report illustrate the value of minimizing test variation by replacing the generic roof construction with a burner to replicate flame propagation along the roof surface.

Solar ABCs Interim Report

Grounding Photovoltaic Modules:

The Lay of the Land

Prepared by:

Greg Ball
BEW Engineering

Solar America Board for Codes and Standards

www.solarabcs.org

Solar America Board for Codes and Standards Report

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March 2011

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Download a copy of the report:

www.solarabcs.org/grounding

EXECUTIVE SUMMARY

This report summarizes the current state of codes and standards that apply to equipment grounding of photovoltaic (PV) modules and systems. The Solar America Board for Codes and Standards (Solar ABCs), with support from the U.S. Department of Energy, commissioned this work with the intent of providing the PV industry with practical guidelines and procedures for module grounding. This initial "lay-of-the-land" report sets the stage for a final report that will draw on feedback from industry experts as well as ongoing research at Underwriters Laboratories, Inc. (UL) to develop guidelines and recommendations for changes to existing standards.

Although there are many PV module and system grounding issues, I will focus on two principal industry concerns. The first is solar professionals' lack of confidence in existing, approved grounding methods, which results from the many grounding failures in fielded systems. Although statistical studies of failure rates are not available, there is enough anecdotal evidence to support recommendations for additional testing and revision of standards.

The second is the limited number of approved grounding methods and devices available for PV modules and systems that are certified or listed by nationally recognized testing laboratories. Industry stakeholders who would prefer to market or use new grounding methods and devices point out that the absence of certification for these products is not necessarily based on issues pertaining to safety or reliability, but rather results from a lack of consensus in the assignment and development of applicable standards.

At present, there are a host of limitations, ambiguities, and conflicts among the standards that apply to PV module and system grounding. UL 1703 (Flat-Plate Photovoltaic Modules and Panels) is the primary governing standard for grounding modules, and it requires module manufacturers to manage all methods of frame grounding. This has hampered the ability of third party grounding components suppliers to certify innovative system-level grounding measures. UL 467 (Grounding and Bonding Equipment) could serve the third party supplier market, but in its current form it is not widely applicable to PV systems. UL 2703 (Rack Mounting Systems and Clamping Devices for Flat-Plate Photovoltaic Modules and Panels) is a draft standard that will, in time, address system level mounting and grounding. UL 2703 currently includes the same overall grounding language that is in UL 1703. This standard—together with a UL 467 revised to address PV systems—has the potential to be the long-term solution to today's issues by providing a clear and effective course for manufacturers of modules, structures, and grounding components to have their components tested and listed.

There is much developmental activity within all three of these standards. UL has conducted a set of aggressive environmental tests intended to characterize corrosion related problems and failures, and expects to published the results in the first quarter of 2011. After debate and deliberations, these test results will inform revisions to the standard testing requirements. There is also a comprehensive proposal to update and improve grounding related sections in UL 1703 (and by extension UL 2703), and to provide parallel courses of certification through UL 467 and UL 1703.

The near-term goals between now and the completion of this study are to engage in and monitor the standard development activities and to conduct additional research into outstanding issues (corrosion, current testing, personal safety criteria, etc.). The results will inform the final revisions of all of the appropriate standards.

"This initial "lay-of-the-land" report sets the stage for a final report that will draw on feedback from industry experts as well as ongoing research . . . to develop guidelines and recommendations for changes to existing standards."

The topic of PV system grounding as a whole covers a wide range of issues outside the scope of this study, including the bonding and grounding of support structures and their multiple internal components, system level equipment ground and electrode ground conductor strategies, lightning protection, grounding of specialized equipment such as AC modules or similar integrated DC/DC converters, and others. Solar ABCs is considering an additional study to address these and other issues.

Author Biography

Greg Ball

Greg Ball is a Principal Engineer at BEW Engineering, and has more than 20 years experience in renewable energy technologies and their integration with the utility grid. Before joining BEW in 2009, he worked for nine years as manager and senior electrical engineer at PowerLight (later SunPower) Corporation, where he was responsible for the electrical design of large-scale photovoltaic system projects in the United States and abroad. He was chief electrical engineer for more than 90 MW of solar power plant installations in Germany, Portugal, and Spain. He has been active in several policy and standards activities, serving as co-convenor on an International Electrotechnical Commission (IEC) PV system working group, a member of California's Rule 21 committee on utility interconnections, a contributor to the National Electrical Code (NEC) photovoltaic code-making panel, and a contributor to various Institute of Electrical and Electronics Engineers (IEEE) activities. Before he joined PowerLight, Mr. Ball held positions at Pacific Gas & Electric and utility consulting companies, where he focused on the distribution system impacts of power conversion based renewable and energy storage technologies. He has co-authored numerous publications on the topic, including an *IEEE Industry Applications Magazine* article that earned that publication's 2006 Prize Paper Award. Mr. Ball earned a bachelor of science in electrical engineering from Tulane University, and a master of science in electrical engineering with a power electronics focus from the University of Tennessee. He is an IEEE member.

Solar America Board for Codes and Standards

The Solar America Board for Codes and Standards (Solar ABCs) provides an effective venue for all solar stakeholders. A collaboration of experts formally gathers and prioritizes input from groups such as policy makers, manufacturers, installers, and large- and small-scale consumers to make balanced recommendations to codes and standards organizations for existing and new solar technologies. The U.S. Department of Energy funds Solar ABCs as part of its commitment to facilitate widespread adoption of safe, reliable, and cost-effective solar technologies.

Solar America Board for Codes and Standards Web site:

www.solarabcs.org

Acknowledgements

This material is based upon work supported by the Department of Energy under Award Number DE-FC36-07GO17034.

Table of Contents

DISCLAIMER ii

EXECUTIVE SUMMARY iii

AUTHOR BIOGRAPHY iv

SOLAR AMERICA BOARD FOR CODES AND STANDARDS iv

ACKNOWLEDGEMENTS iv

INTRODUCTION 1

EXISTING STATE OF AFFAIRS 2

TYPICAL FAILURE MODES 2

APPROACHES AND METHODS THAT ARE WORKING 6

COST ISSUES 7

APPLICABILITY AND ISSUES WITH EXISTING STANDARDS AND TESTS 7

WHERE TO GO FROM HERE 9

UL 1703 Section 11 9

CURRENT TESTS 13

Environmental and Corrosion Resistance Testing 14

CONCLUSIONS AND RECOMMENDATIONS 16

APPENDIX A: Excerpts from Grounding Requirement Proposal for UL61730-1, submitted by John Wiles with Support of Others, 2008 17

APPENDIX B: New IFC and UFC Regulations Under Development 20

ACRONYMS 21

INTRODUCTION

This is the first of a two-part study of photovoltaic (PV) module equipment grounding issues. The Solar America Board for Codes and Standards (Solar ABCs), with input from a large cross section of U.S. stakeholders, identified the need for this study through a gap analysis process. The objective of this study is to make recommendations for an integrated set of tests and procedures that can be incorporated into the standards governing the grounding of PV components. This report will be followed by a final report that describes practical, publicly available proscriptive procedures that clarify this long-standing and contentious issue. New or expanded test methods will be developed for the purpose of evaluating the long-term reliability of the connections to and between metal parts in a PV array for roof- or ground-mounted systems.

Throughout this document, the terms "ground," "grounding," and "grounded" are used to describe the connections to module frames that are the primary focus of the study. Note that there is a distinction between "grounded" and "bonded." The National Electrical Code (NEC) defines these terms as follows:

- Grounded: Connected to earth or to some conducting body that serves in place of earth.
- Bonded: The permanent joining of metallic parts to form an electrically conductive path that ensures electrical continuity and the capacity to conduct safely any current likely to be imposed.

Much of the scope of this study focuses on the bonding of frames to other parts or conductors that are then grounded. The report uses the more general "grounding" term to describe both bonding and grounding unless bonding is specifically called out.

PV modules are typically installed on aluminum or galvanized, painted, or stainless steel frame structures. These structures and any other electrically conductive components that may become energized by the PV array (or other sources) and that may be accessible during routine servicing, must be bonded to ensure safe touch voltages. Module manufacturers currently provide detailed directions for grounding the modules in their installation manuals. Manufacturers of grounding equipment for PV modules have developed components designed for general use, and have pursued different approaches for certifying or listing these devices. There is little industry consensus on the appropriateness or completeness of the available standards for these general use components.

The result has been a large number of fielded systems that demonstrate:

- unsatisfactory module grounding measures,
- violations of the module's Underwriters Laboratories (UL) 1703 listing because the installation does not comply with the installation manual's prescribed method of module frame grounding,
- incorporation of components listed to more general grounding equipment standards that may or may not be suitable for the application, and/or
- well-engineered grounding means that have, at present, no clear path for demonstrating their adequacy to customers and inspectors.

This overall module grounding study attempts to address these issues via the following steps:

- *Develop this preliminary report, referred to as the "lay-of-the-land report."* This is primarily a BEW Engineering-led survey of the existing situation in which stakeholders (system designers, module and component manufacturers, Nationally Recognized Testing Laboratories [NRTLs], and researchers) share their experiences and recommendations related to the issues listed above.

- *Evaluate existing and new test procedures.* This is primarily a UL-led effort to investigate expanded or enhanced testing methods that can provide greater confidence in the long-term reliability of grounding methods.
- *Develop a final report that incorporates results and feedback from these two efforts.* This report will make recommendations for a set of tests to incorporate into existing or new standards, and document clear guidelines and procedures for public use.

This lay-of-the-land report addresses the following topics:

- General description of the existing state of affairs in PV module equipment grounding.
- Typical bond failure modes.
- Approaches and methods that are working.
- Installation issues.
- Permitting issues.
- Cost issues.
- Applicability and issues with existing standards and tests.
- UL's current activities to address testing deficiencies or needs.
- Industry activity and anticipated changes.

The topic of PV system grounding as a whole covers a wide range of issues outside the scope of this study, including the bonding and grounding of support structures and their multiple internal components, system level equipment ground and electrode ground conductor strategies, lightning protection, grounding of specialized equipment such as AC modules or similar integrated DC/DC converters, and others. Solar ABCs is considering an additional study to address these and other issues.

EXISTING STATE OF AFFAIRS

The sections below cover many issues that can be summarized in two key observations:

- Existing standards do not adequately ensure long-term, reliable, and safe grounding of PV modules.
- Standards lack guidance for evaluating alternative equipment or methods of PV module grounding.

TYPICAL FAILURE MODES

As we begin assessing the current state of PV module and system grounding, it is appropriate to start with the modes under which presently used grounding connections fail. Grounding failure is broadly defined as a connection no longer capable of reliably providing sufficient and appropriate electrical continuity between components. This includes disconnections, loose connections in which continuity is intermittent or weakening at an unacceptable pace, and connections exhibiting corrosion of the material's sacrificial layer and reduced continuity.

A failed connection can take many forms, including but not limited to:

- A loosened nut and/or screw where a ground wire is attached to the module frame with a pre-drilled or field installed hole.
- A loosened nut and/or screw where a ground lug or terminal is attached to the module frame with a pre-drilled or field installed hole.

- A loosened clamp-type bond between the module frame and its clamp device, or between the clamp device and the external bonded equipment.
- A connection in which bonding relies on screw threads and there is insufficient continuity due to insufficient thread contact.
- A connection in which bonding relies on penetration of an anodized frame, or non-conductive frame coating such as paint or vitreous enamel, and where that penetration is insufficient. The bond in this case typically relies on the use of a star washer or serrated screwhead to penetrate the coating.
- A connection using specialized grounding devices in which bonding relies on penetration of the anodized frame or frame coating and where that penetration is insufficient. An example is a clamped device with a sharp point or edge used to penetrate the coating.
- Corroded connections in which the corrosion has either broken down one or both of the bonded conductor materials or has created an insulation barrier between them.

Loose connections can be caused by:

- Over-torquing the bolted or screwed connection, resulting in partial stripping or damage to the frame, which damages the ground component assembly.
- Under-torquing the bolted or screwed connection.
- Stressing the connection during or after installation without re-torquing.
- Drilling into the frame or bolting a connection at an improper angle, thereby failing to achieve the proper tight contact.
- Using incorrect washer/nut or assemblies that do not result in a durably tight connection.
- Using an improperly sized screw/bolt/nut/washer in the assembly.
- Using an improperly selected, sized, or installed clamping device.
- Continually stressing a connection post-installation by applying more tension on the ground wire or force on the assembly than it can reliably endure. An example is a ground cable pulled so tight that it compromises the assembly or the frame itself.
- Improperly selecting the screws, resulting in insufficient thread contact in bonds using screw threads.
- Repeated installing of a self-drilling or thread forming screw.
- Temperature cycling that exceeds the withstand capabilities of the bonding components or their assemblies.
- Non-uniform expansion and contraction from thermal cycling that exceeds the withstand capabilities of the bonding components or their assemblies.

Penetration failures can be caused by:

- Under-torquing the bolt/assembly such that the star washer or serrated bolt surface does not break the frame coating.
- Using improperly sized/selected/installed components in the assembly, including the star washer or serrated component itself. In this case, the washer may be installed backwards, in the wrong position, or—if improperly sized—it may be deformed during tightening so that the sharp edge does not engage with the frame. (UL has observed in environmental testing that results may differ depending on whether the star washer is part of the turning assembly during the installation or part of the fixed assembly.)

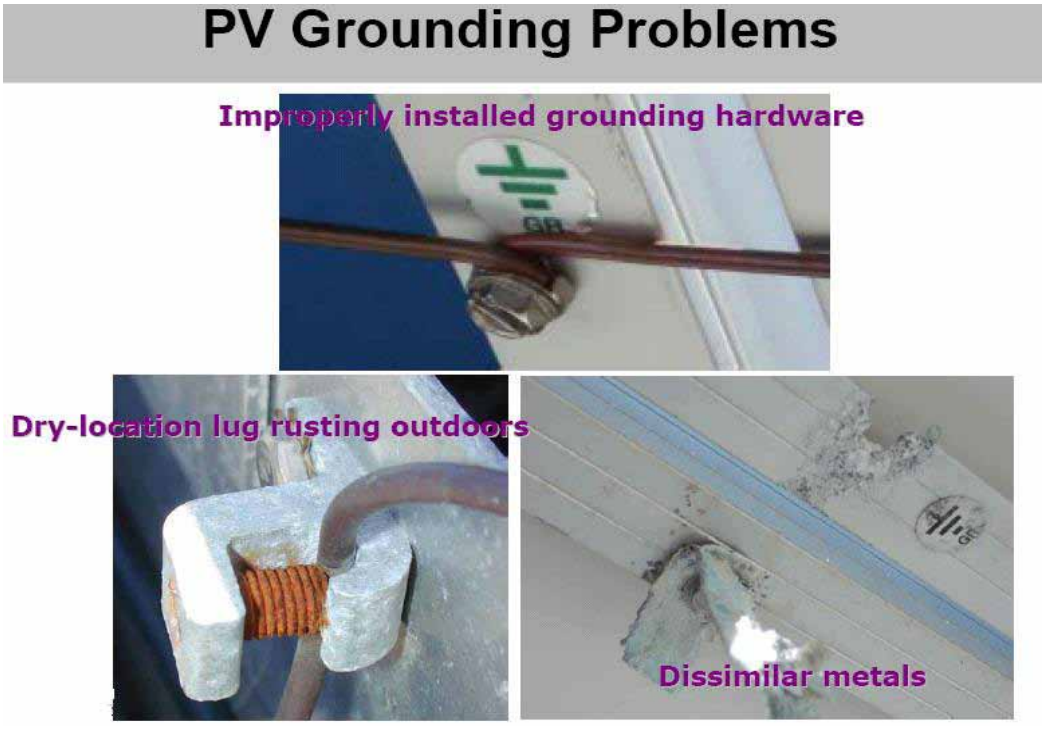
- Using improper or incorrect specialized piercing components designed for other frame or component shapes.
- Inadequate testing, quality control, or improper handling of the specialized components themselves, which can lead to failure.

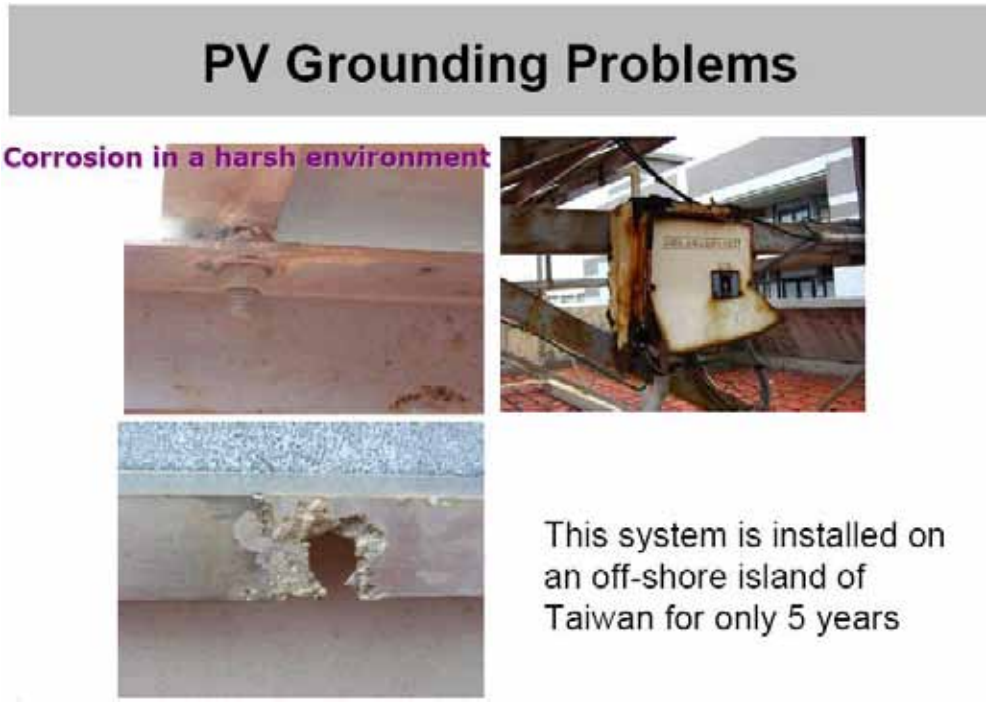
It is important to note that corrosion itself does not imply failure. There is often the expectation of superficial corrosion. Failure occurs only when the bond impedance rises (as a result of excessive corrosion) to a point where an unsafe condition is created or proper operation of protection devices is inhibited (during normal or faulted operation).

Failures from corrosion can have many causes. Galvanic corrosion resulting from the joining of dissimilar metals is probably the most common general cause. However, corrosion can also occur as a result of long-term exposure of components to cycling leakage current, which produces an electrolysis process. Failures due to corrosion can be attributed to the following general causes:

- Improper selection of materials for the bonded connection. Copper and aluminum bonds are the most common and have dramatic results, but other less obvious combinations may break down over time. (See the *Applicability and Issues With Existing Standards and Tests* section for more on this topic.)
- Dissimilar metals in close proximity, which—depending on the electrolyte involved—causes corrosion when exposed to water, soil, or other conductive debris elements.
- Insufficient barriers between dissimilar metals, such as undersized or badly installed stainless steel washers separating copper and aluminum.
- Good but inadequately protected connections after long-term exposure to leakage current, water, salt-humidity, and/or other corrosive agents. An example is a tin-coated assembly joining a copper wire and aluminum frame where the coating is inadequate to serve as a sacrificial barrier over the long term.

The following photos illustrate issues and failures of PV module and system grounds found in the field.





Poor installation connection

Connection of dissimilar (incompatible) materials

Photos caption: *The photos demonstrate a wide variety of issues, some clearly indicating failure of a bond, and some indicating a method issue or apparent problem even if the bond is safely intact. The variety is indicative of the task ahead for improving standards and industry methods. Careful attention needs to be paid to distinguishing real problems from perceived problems, and using the experience of other industries to the extent possible to avoid over-reaching requirements.*

Photo credit: *John Wiles, Southwest Technology Development Institute, New Mexico State University*

APPROACHES AND METHODS THAT ARE WORKING

There are many examples of PV systems with module ground bonds that have performed well for many years, including all of the types of connections described above. The most common are properly installed wired grounds using proper connections and compatible metals. Durable screw/bolt/nut/clamp assemblies of compatible metals that are properly sized, torqued, and checked provide a gas-tight seal and have long proven reliable when located in relatively benign environments. Best practice may also include the use of a protective coating, such as No-Ox, on the connection, which extends the useful life of the bond.

Many in the industry make the case that methods using clips, clamps, or other mechanical bonds between modules, rather than frame-to-frame ground wires, are proving to be equally reliable. Large rooftop systems using multiple grounding clamps or devices that are part of the overall assembly, for example, may be less prone to installation problems (based on anecdotal reports). Device-based methods may be more compatible with repetitive labor processes across large arrays than the labor-intensive steps associated with wiring of washer/screw/nut assemblies from module to module. When clamp devices are part of the overall mechanical assembly, they also provide a level of redundancy that wire-based approaches don't have by providing multiple paths for ground current flow.

At present, it is difficult to report the long-term reliability of these newer, less traditional grounding methods because their field history is short. Another factor that hinders this assessment is that module frames themselves have changed over time with some using thinner gauge metals that may reduce long-term bond reliability. This investigation does not include a statistical assessment of how module frame shapes or gauges may affect bond reliability, but there is anecdotal evidence to indicate that less common shapes or profiles may be more prone to bond installation issues (i.e., user error), particularly when installers use components designed for other, more "standard" frames.

A number of contributors to this discussion on module grounding have concluded that it may be unrealistic to expect a grounding solution to last for the life of a PV system without additional environmental protection or periodic maintenance. This can be particularly true in corrosive environments. There is no consensus on how corrosive the environment must be to warrant such a disclaimer, although locations with routine exposure to chemical or salt spray or humidity are likely candidates. In their proposal to the Standard Technical Panel (STP) for UL 1703, SunPower specifically cited ISO 9224 Category C5.[1]

Nonetheless, for less extreme environments, the goal is grounding methods and practices with design lives equal to or better than the life of the PV system itself. Grounding means in other industries, such as utility, industrial, and petrochemicals have demonstrated this capability.

One recommendation of this preliminary report, therefore, is to seek additional industry expertise (to complement results of ongoing exploratory UL testing) to provide specific guidance for installation and maintenance expectations, as a function of environmental categories and bonding methods.

[1] ISO 9224 (1992): "Corrosion of metals and alloys -- Corrosivity of atmospheres -- Guiding values for the corrosivity categories." Category C5 indicates "very high" corrosivity, and includes two sub-categories: C5-I (Outdoor air: very humid industrial atmosphere), and C5-M (Outdoor air: saline seaside atmosphere).

COST ISSUES

The cost for compliance is always a concern as existing and new standards evolve. Existing, approved grounding methods have evolved from the industry's early focus on small PV systems. On these small systems, running a ground wire from one module to another does not usually present a cost burden. But as systems have grown to incorporate tens of thousands of modules, a more efficient means of bonding from module to module or module to metallic support structures may yield both material and labor savings. Because present standards limit the application of general use grounding components, integrators and installers of large systems often report that the existing, approved methods are unnecessarily burdensome and costly.

Statistical cost analyses were not conducted for this preliminary study, but anecdotal cost information indicates that ground equipment and labor cost savings associated with the use of device-based methods may range from 20% to 60% compared with conventional wiring-based methods. Labor savings alone can exceed 50% when compared with wiring-based methods.

APPLICABILITY AND ISSUES WITH EXISTING STANDARDS AND TESTS

This section describes the various standards that have bearing on PV module and system grounding. There are a number of unresolved or conflicting issues associated with these standards, and they can conflict with the NEC. In his introduction to proposed language for UL 61730, John Wiles of the Southwest Technology Development Institute at New Mexico State University stated that the instructions required in UL 1703 have been at odds with the requirements in the NEC for at least twelve years and recent changes in the NEC have not been reflected in the module standards.

Standards that currently (or may in the foreseeable future) address module frame grounding include:

UL 1703: *Flat-Plate Photovoltaic Modules and Panels*

UL 467: *Grounding and Bonding Equipment*

UL 1741: *Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources*

UL 2703: *Rack Mounting Systems and Clamping Devices for Flat-Plate Photovoltaic Modules and Panels*

UL 61730-1: *Photovoltaic (PV) Module Safety Qualification - Part 1: Requirements for Construction*

UL 1703 is currently the "primary" standard affecting module grounding and devices. Methods certified to UL 1703 and documented in module manufacturers' listed installation instructions are almost universally accepted by inspectors and authorities having jurisdiction (AHJs). The standard covers a range of safety and construction related requirements for modules, with a few sections dedicated to frame bonding, grounding, and continuity. UL 1703 establishes requirements for the means of grounding as well as continuity requirements subject to applied current and environmental (accelerated life) testing.

As the previous sections stated, the primary issues or concerns associated with UL 1703 as reported by the industry are that:

- it does not provide adequate assurance or guidance for long-term grounding reliability, and

- it is too restrictive in its approach and process to facilitate certification of third party devices.

UL 467 is dedicated to grounding and bonding equipment and is widely perceived in the industry to be a good template, if not the complete answer, to certifying third party, general use ground components. UL 467 currently suffers from a much-contested perception that it is not appropriate for components in a PV system application. Indeed, the authors of the standard have stated that, as written, it does not address some unique aspects of PV system applications. Strictly speaking, it covers only indoor or direct-buried connectors, although that designation is commonly applied to outdoor installations. Others counter that the tests, even though they were written without considering PV systems, lead to adequate qualification of a module-grounding device.

It should be noted that recently UL has initiated a Certification Requirements Decision (CRD) for UL 467 to incorporate PV module grounding device requirements. Historically, UL has not supported the use of UL 467 for this purpose and the controversy was one of the drivers for UL's 2007 CRD. The CRD was issued more or less as an addendum to UL 1703. The CRD adds explicit language tying any grounding means or method to evaluation under UL 1703: "A grounding means shall be provided with each module or specified in detail in the module installation manual that is provided with each module so as to comply with the requirements in 11.1 and Section 48." This requires module manufacturers, if they're not certifying grounding components and means themselves, to specify in detail any acceptable methods or means in their installation manuals.

All of this leads to the primary permitting issues facing the industry. The CRD is not universally applied by NRTLs, who have latitude in determining how standards are implemented. This has led to lack of uniformity in product and installation approval by inspectors and AHJs. Inspectors aware of the discrepancy have, in some cases, begun differentiating approval based on which NRTL is involved (approving components with UL stickers while rejecting others). In addition, module manufacturers have withdrawn product bulletins that had been released to express approval for use of certain third party, general use ground components because they came into conflict with the CRD. The uncertainty around permitting requirements is serious and costs the PV industry significant time and money. However standards evolve to address the issues identified in this report, the industry will be well served to have clear marking and identification of grounding components for AHJ review and approval.

UL 1741 addresses power conversion equipment, but it is included in discussions of module grounding because of the ground circuit fault current tests it incorporates. Also, new technologies are placing the power conversion components at the module and even embedding them in the module. This current test topic will be addressed in more detail in the next section.

"The uncertainty around permitting requirements is serious and costs the PV industry significant time and money."

UL 2703 is a new standard under development that was created to address PV module mounting systems. Officially, it is an Outline of Investigation for rack mounting systems and clamping devices. In practice, however, it is already available for purchase as a draft standard and UL has begun testing for various equipment suppliers. It covers structural and other general issues for mounting systems, including grounding. The grounding section applies much of the same language used in UL 1703 to the mounting system components. UL is planning to list grounding components independent of the racking certification through this standard. There is also the intent to establish subsystem level testing of bonding—for example, tests using multiple modules and components connected together, rather than single connections—and impedance requirements for metal apparatus containing multiple strings of modules. It is expected that the standard

will quantify ampacity and cross sectional area requirements, similar in principle to the approach taken for the cable tray systems used instead of conduit to support electrical and communication cables.

UL 61730-1 is intended to describe the fundamental construction requirements for PV modules in order to provide safe electrical and mechanical operation during their expected lifetime. It is discussed here largely for the proposed language submitted by John Wiles in 2008 on behalf of a small group to address deficiencies in UL 1703.

WHERE TO GO FROM HERE

At present, there is significant momentum behind proposals being drafted by Brooks Engineering and a cross-industry group formed by Wiley Electronics. These were addressed at a UL 1703 Standards Technical Panel (STP) meeting held in December 2010. The new proposals have evolved from past discussions and proposals, most notably by Wiley Electronics, John Wiles, SunPower, Brooks Engineering, and SunLink.

The general intent of these and other proposals, including those by Wiley, SunPower, and others, is to allow grounding equipment manufacturers to list grounding means or products under UL 1703, or, if the product is for general use, under UL 467. SunLink, for example, has listed grounding products under UL 1703 by providing details about the specific module brand and model frames with which its grounding components have been tested. With the general use approach, it should not be necessary to provide a separate listing for each part in combination with each possible module, but should be possible to provide a set of application parameters based on testing that clearly establishes modules and subcomponents for which the devices are compatible. This will include cautions against application parameters that are not appropriate.

As an example of this, Wiley Electronics created a draft testing proposal for its Washer, Electrical Equipment Bond (WEEB) products that provides descriptions and diagrams detailing the minimum thickness, rigidity, profile, and cross section requirements for module frames. It provides additional guiding parameters for the interconnecting components (i.e., components to which the modules are bonding), the mounting hardware, and the required contact area to ensure proper application. This process may be improved further with the establishment of standardized frame categories that address thickness, coating type and thickness, rigidity, and shape.

To cover the issues, discussion, and opinions regarding these standards, we will list the relevant requirements of UL 1703 Section 11, Bonding and Grounding, along with accompanying discussion points and proposed changes. Sections 11.9 through 11.12 covering marking and identification requirements are excluded. Following this is a separate discussion of two major testing issues—current tests and accelerated life/corrosion tests.

Many of these issues were also addressed in proposed language for UL 61730-1, created by a group of STP and other participants, and submitted by John Wiles in 2008. Sections of this proposal are included in Appendix A. Especially noteworthy is the full description of requirements for external field connections, specific tests cited for continuity, and specific tests cited for torque.

UL 1703 Section 11

11. Bonding and Grounding

11.1 A module or panel shall have a means for grounding all accessible conductive parts. The grounding means shall comply with the applicable requirements in Connection Means, Section 10. The grounding means shall be bonded to each conductive part of the module or panel that is accessible during

normal use. The grounding means shall be described in detail in the installation manual. See Installation and Assembly Instructions, Section 48.

Exception: When the grounding means is a module or panel mounting member intended to contact an array structural member, the module or panel grounding means are not required to comply with the requirements for Connection Means, Section 10.

Wiles, Wiley Electronics, and others have proposed making a greater distinction between requirements for bonding frame components within the module, and those for bonding to components exterior to the module. Some of the existing language, clearly written for internal bonding, can be confusing if read to apply to external bonding. The proposals clearly separate the sections and there seems to be consensus on the change.

11.2 Routine maintenance of a module or panel shall not involve breaking or disturbing the bonding path. A bolt, screw, or other part used for bonding purposes within a module or panel shall not be intended for securing the complete device to the supporting surface or frame.

11.3 Bonding shall be by a positive means, such as clamping, riveting, bolted or screwed connections, or welding, soldering (see 11.5), or brazing. The bonding connection shall penetrate nonconductive coatings, such as paint or vitreous enamel.

Proposals from Wiles and Wiley Electronics have expanded on the examples of non-conductive coatings to include oxidized metal, anodizing, and clear coatings. SunPower's proposal for external grounding emphasizes expanding this and similar sections to require installation manual descriptions by either the device manufacturer (e.g. minimum thickness and appropriate profile) or the module manufacturer (minimum requirement for the means of attachment). It also calls for minimum and maximum installation torque or force requirements to be specified.

11.4 A bolted or screwed connection that incorporates a star washer under the screwhead or a serrated screwhead may be acceptable for penetrating nonconductive coatings. If the bonding means depends upon screw threads, two or more screws or two full threads of a single screw shall engage the metal.

SunPower's proposal adds language requirements in the installation manual (again for external bonding) that specifies thread pitch for means that depend on screw threads. For methods using self-tapping or thread-forming screws, it also includes a requirement that module installation manuals must state specific requirements and limitations with respect to how many times self-tapping or thread forming screws can be inserted in the same location. This addresses concerns shared by many that, in practice, self-tapping screws are sometimes re-installed and should either be moved or tested to demonstrate a certain number of insertions in the same location.

The STP proposal calls out a specific set of external grounding means to be added:

- A terminal for connecting an external grounding conductor.
- A lead that is electrically bonded to the frame.
- A device that effectively and durably bonds the module frame to a mounting rack.
- A device that effectively and durably bonds the module frame to an adjacent module frame when used in conjunction with listed grounding means for the system of bonded module frames.

The terminal or lead option should be compatible with both copper and aluminum conductors and should prevent copper conductors from contacting an aluminum module frame at the connection point.

11.5 All joints in the bonding path shall be mechanically secure independent of any soldering.

11.6 A separate bonding conductor or strap shall:

a) Be of copper, copper alloy, or other material acceptable for use as an electrical conductor;
b) Be protected from mechanical damage; and
c) Not be secured by a removable fastener used for any purpose other than bonding, unless the bonding conductor is unlikely to be omitted after removal and replacement of the fastener.

11.7 A ferrous metal part in the grounding path shall be protected against corrosion by metallic or nonmetallic coatings, such as painting, galvanizing, or plating. Stainless steel is acceptable without additional coating.

11.8 A metal-to-metal multiple-bearing pin-type hinge is considered to be an acceptable means for bonding.

There is a range of proposals for clarifying and/or expanding on the use of appropriate metals, and avoiding inappropriate dissimilar metals to meet the objective of paragraph 6.8 from 1703:

6.8 Metals used in locations that may be wet or moist shall not be employed in combinations that could result in deterioration of either metal such that the product would not comply with the requirements in this standard.

UL's 2007 CRD introduced a matrix of acceptable and unacceptable metal combinations that can be used in the grounding means, shown in the figure below. Acceptable combinations are those resulting in combined electrochemical potentials of less than 0.6V, which are those shown below the stepped cutoff line.

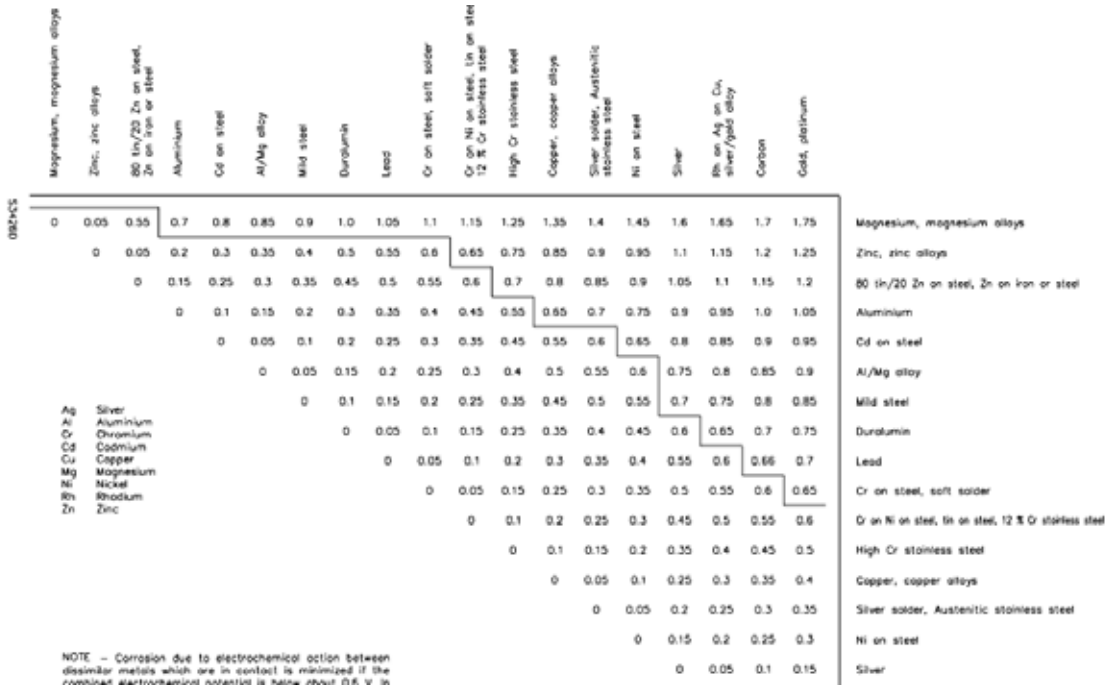


Figure: Electro-chemical matrix of common metal combinations

SunPower's proposals disputed some findings in the table, and—partly to prevent misapplication—proposed a minimalist set of acceptable combinations that covers the vast majority of currently acceptable approaches. Other combinations would not be prohibited, but the onus would be on the manufacturer to investigate and demonstrate their acceptability.

SunPower's specific suggestions included:

- A requirement (with exception described above) that grounding devices and mounting means shall be constructed of:
  - copper or a copper alloy containing not less than 80 percent copper, which may be coated or plated to avoid galvanic corrosion;
  - stainless steel containing a minimum of 16% chromium (Cr) or 5000 or 6000 series aluminum alloys; and
  - carbon steel, which may be coated or plated to avoid corrosion.
- An explicit requirement that there be *"no direct contact between different metals that may exhibit galvanic corrosion in atmospheric environments either between parts within the grounding device, or when the device is attached as specified to the accessible conductive part."*

The acceptable combinations include any combination of:

- 5000 or 6000 series aluminum alloys and commercially pure aluminum,
- stainless steel containing a minimum of 16% Cr,
- nickel,
- tin,
- zinc, and
- zinc-aluminum alloys.

These material combinations are galvanically compatible in almost all service environments. However, plating or coatings must be of sufficient thickness and quality to withstand the service environment for the service life in order to provide an effective buffer layer. The basis of the minimum Cr composition is that stainless steels that contain less than 17% Cr, while providing effective continuity, may exhibit rapid surface staining, which is likely to be construed as corrosion by inspectors and customers. Type 316 stainless, which contains 16% to 18% Cr, is the most commonly selected highly corrosion resistant alloy.

- An installation requirement that *bare copper conductors be located at least one-quarter inch from the aluminum frame of the module to prevent moisture accumulation and effective contact between the two metals.* Wiles notes that bare copper conductors are typically used for equipment-grounding conductors for modules and that inadvertent (not for grounding) contact between the copper conductor and aluminum module frame is not detrimental. Some aluminum may be corroded away, but because the connection is not intended and the copper conductor is not compromised, there is no harm in this common contact. However, even if this doesn't directly impact the quality of the grounding connection, corrosion damage to the aluminum module frame may also be a concern for the general installation.

SunPower also suggested that if the table is to be used, or a blanket requirement that acceptable materials should have electrochemical potentials less than 0.6V, then the specific conditions under which the electrochemical potential measurements were taken should be clarified or cited. For additional guidance, they pointed to the use of ASTM G82 Standard Guide for Development and Use of a Galvanic Series for Predicting Galvanic Corrosion Performance.

John Wiles has identified another tangential issue. He noted that in most applications, mechanical threaded fasteners are primarily used to force electrical conductors or materials together to create an electrical bond, although the fasteners themselves are not intended to be the primary current carrier. He proposes that grounding instructions prohibit or discourage using stainless-steel washers or other dissimilar-metal isolation devices between a copper conductor and aluminum module frame unless the hardware has been specifically tested under the new grounding device requirements. Not testing

the isolation devices as electrical conductors could cause the steel screw to carry most of any fault current through the connection. Others have commented that this issue could be addressed more generically, rather than requiring prescriptive certification of specific modules, screws, washers, etc.

Current Tests

Somewhat separate from the requirements for grounding means and methods is their electrical performance. The table below summarizes tests now applied under 1703 for module certification, tests for (AC) general use components under 467, and tests derived from UL 1741.

	UL 1703	UL 467	UL 1741 (short-term)
Test Current	2 x module series fuse rating (e.g. 30A)	Current requirement dependent on ground conductor size, e.g. 750A for #10 AWG	1.000A, e.g.
Test Duration	Sufficient to measure impedance	4 seconds	TBD – until string sized fuse, e.g. 15A operates.
Result Requirement	Resistance between ground connection and accessible conductive part should be < 0.1 Ohm, repeated after temperature, humidity, and corrosive atmosphere tests.	"The fitting shall not crack, break, or melt" Repeated after environmental tests.	Resistance between ground connection and accessible conductive part should be < 0.1 Ohm, tested with 25A @ 60 Hz.

There has been much commentary on appropriate current tests in previous STP discussions and more recently at the STP meeting in December 2010. The points are summarized below:

- UL 1703 uses a relatively low current test based on the maximum series fuse rating to address the potential current flowing through the bonding path for some period of time before the string fuse would be expected to blow. Low current is also representative of anticipated leakage currents that will naturally flow and increase with age (much less than 30A, typically). Some believe, therefore, that this is more representative of the actual conditions and parameters the module is likely to experience in its lifetime.
- UL 1703 could be simplified to allow more generic component testing at 30A, rather than as a function of each and every module's series fuse rating. Many also expect that this test should be performed for longer periods while the modules are undergoing environmental exposure tests rather than performed separately.
- John Wiles is among those who prefer UL 1703 to high current tests. He argues that the low current test could reveal issues not observed in proposed high current tests because of the potential for high currents to bridge, weld, or break down gaps that would otherwise result in lowered continuity.

- Others believe the higher current tests used in UL 467 or UL 1741 are more appropriate for the application. It is a fact that the grounded equipment (i.e. frame) in a faulted string of modules can experience the full array short-circuit current (limited by ground circuit impedance) briefly before the string fuse blows. Systems using AC modules also create potential for short-term AC fault current subject to the time-current curves of the over-current protection device (OCPD). Non-isolated inverters can also cause the utility voltage to appear on the module frame under some single fault conditions. Ultimately the system (inverter) ground fault detection devices should interrupt this current, but the equipment will experience a transient current spike prior to OCPD clearing. So a fast test at 1,000A, for example, is not unrealistic. Several, including Wiley Electronics, SunPower, and SunLink have endorsed the use of such a test to demonstrate the integrity of specific and general use grounding components. Wiley Electronics specifically endorses using UL 467 with a table tying current levels to the size of the ground wire.
- Discussions at the STP meeting related to the revision of UL 467 and whether low or high current tests should be used led to a general consensus that both should be required for certification of module and general use components. Additional proposal language was developed addressing proper sequences of current tests performed before and after environmental conditioning tests.
- The current testing criteria generally addresses impacts of bond failure and impedance degradation on maintaining an effective equipment ground connection—that is, ensuring OCPD device operation will not be compromised. These directly impact personal safety issues as well, but additional considerations of safety will also need to be addressed. The subsequent work in this study will include a review of safety related fault scenarios that will identify conditions under which touch-safe voltages or currents may be exceeded. This work will draw on established safety related criteria, such as International Electrotechnical Commission (IEC) Technical Specification 60479.2, which describes current threshold levels and their effect on the human body. It will also rely on guidelines used in the NEC to designate circuit safety categories (Class 1, 2, and 3 circuits). Results of this analysis will provide guidance in answering basic questions related to the total acceptable resistances in the ground connections in a given area to maintain safety at the module frame.

Environmental and Corrosion Resistance Testing

UL 1703 specifies the following tests on ground connection samples, after which the continuity tests must be repeated:

Section 35—Temperature Cycling Test, 200 cycles of various temperature changes from as low as minus 40 to plus 90 Celsius.

Section 36—Humidity Test, 10 cycles of humidity-freezing.

Section 37—Corrosive Atmosphere testing, including saltspray test and moist carbon dioxide/sulphur dioxide test.

Many in the industry believe these tests do not adequately subject components to the rigors experienced in actual installations, so UL has embarked on exploratory tests to inform future revisions. Recently, Liang Ji at UL has conducted enhanced testing which exceeds the requirements of present UL 1703 environmental tests. These tests have been developed to better reveal connection degradation. A preliminary report is due to be released soon. We include a summary of the testing and preliminary results here.

Test procedures included:

- numerous types of ground connectors,
- continuous damp heat and salt mist environmental exposure,
- periodic electrical current cycling,
- measured change in resistance in connections, and
- tests of roof-mounted modules with and without anti-oxidation compound.

Preliminary results included:

- In the salt mist condition, most samples corroded severely and failed in weeks.
- Identical samples in the damp heat chamber were still in good condition.
- Assembly force and anti-oxidant coating affect integrity.
- Failure mechanisms caused by galvanic, pitting, and crevice corrosion were observed.
- Insulating metal oxide formed by corrosion broke the electrical connections and the grounding system failed.
- Some tests show improved performance when current was flowing through the ground connection.
- Results indicate differences in performance are affected by the details of installation, such as the manner in which a star washer is installed.

Industry review of this report will be critical for the development of tests that will ultimately be incorporated into new or revised standards. While it is widely acknowledged that corrosion tests need to be more rigorous, some in the industry have expressed concern about using some of these testing methods, in particular those that are derived from ASTM B117, which involve continuous exposure to salt mist.

SunPower in particular provided comments to the STP pointing out that the corrosion mechanisms induced by the B117 tests often differ from those observed in the field. Their conclusion is that results do not accurately provide a correlation between the accelerated tests and long-term performance in fielded conditions. The B117 practice itself cautions against the use of the method to predict corrosion performance in the field. SunPower cites corrosion experts from the auto and electronics industry who have expressed concerns about the use and interpretation of such tests.

In general, the use of accelerated corrosion test procedures that have not demonstrated correlation with performance in natural environments is of limited value and must be interpreted with caution. Attempting to accelerate galvanic corrosion is particularly problematic. For example, the ASTM reference on corrosion tests and standards states "Accelerated testing to get a result in a shorter time period than would be possible naturally should be avoided whenever possible, because the mechanism of galvanic corrosion can change if the rate is altered significantly" (*Corrosion tests and standards: application and interpretation 2nd Edition*, R. Baboian, 2005, p. 239). Relevant excerpts of ASTM B117 are included in Appendix B for additional reference.

CONCLUSIONS AND RECOMMENDATIONS

This preliminary report documents many of the challenges facing the PV industry today with respect to module grounding standards and reliability. The timing of this report coincides with a significant level of activity at all levels, particularly at UL. There, STP activity has increased again, exploratory tests are being performed, and at least three STPs are taking a fresh look at PV system grounding. Given the fluid nature of PV module and system grounding requirements, here are a few near-term recommendations to consider for the interim:

- Perform research testing to qualify the impact of different current levels in the continuity and component performance tests.
- Monitor and review developments during the revision of UL 467 to incorporate PV system-specific applications.
- Monitor and review results and developments from UL's enhanced environmental and corrosion resistance testing.
- Engage additional corrosion experts outside of the PV industry to help interpret the new test results and provide guidance on how they can be applied effectively in new or revised standards.
- Explore the possibility of developing special tests for coastal environments, again using guidance from other industries (such as the maritime industry) with relevant experience.
- Seek additional expertise on whether and how strain relief and force tests may be incorporated to evaluate grounding means based on the forces experienced during installation.
- Conduct additional research to identify and classify installation environments and to determine how they might impact grounding design, installation, and maintenance decisions.

APPENDIX A: EXCERPTS FROM GROUNDING REQUIREMENT PROPOSAL FOR UL61730-1, SUBMITTED BY JOHN WILES WITH SUPPORT OF OTHERS, 2008.

Section 8 Bonding and Grounding

8.1 Bonding within the module frame—factory connections

8.1.1 Bonding shall be by a positive means, such as clamping, riveting, bolted or screwed connections, or welding, soldering (see 8.1.3), or brazing. The bonding connection shall penetrate nonconductive coatings, such as oxidized metal, clear coatings, paint, or vitreous enamel.

8.1.2 A bolted or screwed connection that incorporates a star washer under the screwhead or a serrated screwhead may be acceptable for penetrating nonconductive coatings. If the bonding means depends upon screw threads, two or more screws or two or more full threads of a single screw shall engage the metal.

8.1.3 All joints in the bonding path shall be mechanically secure independent of any soldering.

8.1.4 A separate bonding conductor or strap shall: a) be of a material electrically and chemically compatible with the module or panel frame material in accordance with 8.4.1 and acceptable for use as an electrical conductor; b) be protected from mechanical damage; and c) not be secured by a removable fastener used for any purpose other than bonding, unless the bonding conductor is unlikely to be omitted after removal and replacement of the fastener.

8.1.5 A ferrous metal part in the grounding path shall be protected against corrosion by metallic or nonmetallic coatings, such as painting, galvanizing, or plating. Stainless steel meeting the requirements of 8.4.1 is acceptable without additional coating.

8.1.6 A metal-to-metal multiple-bearing pin-type hinge is considered to be an acceptable means for bonding.

8.2 Grounding the module frame—field connections

A module or panel shall have a means for connecting all accessible conductive parts to an external grounding (earthing) system. The grounding means shall consist of one or more of the following methods listed in 8.2.1, 8.2.2, or 8.2.3. These grounding means shall be tested following the Ground Continuity Tests MST 13 of ANSI/UL 16730-2.

8.2.1 A Terminal. A terminal shall be used for connecting an external equipment-grounding conductor. The terminal shall be compatible with a copper conductor and shall prevent the copper conductor from contacting the aluminum module frame at the connection point.

8.2.1.1 A terminal of a module or panel (for example, a wire-binding screw, a pressure wire connector, or a nut-on-stud) intended to accommodate an equipment grounding conductor shall be identified by being marked with a grounding symbol, or by "G," "GR," "GROUND," "GROUNDING," or the like, or shall have a green-colored part. No other terminal shall be so identified.

8.2.1.2 If a marking is used to identify an equipment grounding terminal, it shall be located on or adjacent to the terminal, or on a wiring diagram affixed to the module or panel near the terminal.

8.2.1.3 If a green-colored part is used to identify the equipment-grounding terminal, it shall be readily visible during and after installation of the equipment-grounding conductor and the portion of the terminal that is green shall not be readily removable from the remainder of the terminal.

8.2.1.4 The terminal shall be subject to the Terminal Torque Tests of ANSI/UL 61730-2. Where the terminal used cannot pass this test and can be used only once, the instructions provided with the module shall show alternate positions for installing the terminals and provide specific instructions for using those alternate positions.

8.2.2 A Lead. A lead that is electrically bonded to the module frame shall be used for grounding the module or panel. The lead shall be compatible with a copper conductor.

8.2.2.1 The surface of a lead of a module or panel intended for the connection as an equipment-grounding conductor shall be identified by insulation or color coding colored green, or green with yellow stripe(s), or be bare, or bare tinned, without insulation. No other lead shall be so identified. Where an insulated conductor is used, the insulation shall meet the requirements of the insulation used on USE-2 or PV Wire.

8.2.2.2 The lead shall comply with the Strain Relief Tests of 10.6.

8.2.3 A Device. A grounding device that effectively and durably bonds the module frame to a mounting structure or other adjacent modules or panels may be used. This device shall comply with 8.2.3.1 or 8.2.3.2.

8.2.3.1 A grounding device that effectively and durably bonds the module frame to a mounting structure where the mounting structure used is grounded with a means compliant with the requirements of ANSI/NFPA 70, The National Electrical Code.

8.2.3.2 A device that effectively and durably bonds the module frame to an adjacent module frame where the system of bonded modules is grounded with a means compliant with the requirements of ANSI/NFPA 70, The National Electrical Code.

8.2.3.2.1 Devices that penetrate a module coating to establish electrical contact shall specify the maximum coating thickness with which they are compatible in the installation instructions.

8.2.3.3 Devices that attach to a module frame shall specify the minimum area that must be available and the minimum and maximum thickness of the module frame over that area. Clearance depth behind the frame for nut or other attachment device will also be specified.

8.2.4 Grounding means having threaded connections. Any grounding means having threaded connections shall comply with the applicable requirements in Connections 7 and the Terminal Torque Tests of ANSI/UL 61730-2.

8.4 Material Requirements

8.4.1 The module grounding means shall not result in the combination of dissimilar metals shown above the cutoff line in Table DVC-1 of Annex DVC. The following combinations are considered to be acceptable: a) stainless steel (min 17% Cr content)

with Aluminum alloys, tin, zinc, or copper; b) aluminum alloys with stainless steel (17% Cr min), tin, or zinc; and c) other combinations that can be demonstrated to not be susceptible to galvanic corrosion.

The following items will be listed in the instruction manual for each specific module covered by the instructions:

- The thickness of any and all insulating coatings on the frames of the module for areas identified for the connection of field-installed grounding means, including paint, powder coatings, clear coatings, and anodizing.
- The temperature coefficient of open-circuit voltage (Voc) expressed as a percentage change in the Voc standard test conditions (STC) per change in temperature from the STC temperature expressed in degrees Celsius.
- All grounding methods, devices, and materials.
- The OEM part number(s) or the appropriate national or international standard(s) for the hardware if common hardware items such as nuts, bolts, and lock washers are specified rather than provided.

These instructions are part of the listing/certification of the product and shall not be changed without the review and approval of the listing/certification agency. The instructions may specify that an independent grounding means tested and listed to this standard be used. The grounding means shall comply with 8.2 through 8.4. The instructions shall state that any mounting methods not complying with the mounting methods described in these instructions may result in a mechanical attachment that may damage the module or fail to restrain it under high wind loading conditions. Such mounting methods will violate the listing/certification of the module and must be evaluated by the listing/certification agency prior to use. The series overcurrent device required to be marked on back of the PV module shall be identified as “Maximum series overcurrent device, where required.” The words “fuse” or “circuit breaker” shall not be used.

APPENDIX B: EXCERPTS FROM ASTM B117, STANDARD PRACTICE FOR OPERATING SALT SPRAY (FOG) APPARATUS

3. Significance and Use

3.1 This practice provides a controlled corrosive environment, which produces relative corrosion resistance information for specimens of metals and coated metals exposed in a given test chamber.

3.2 Prediction of performance in natural environments has seldom been correlated with salt spray results when used as standalone data.

3.2.1 Correlation and extrapolation of corrosion performance based on exposure to the test environment provided by this practice are not always predictable.

3.2.2 Correlation and extrapolation should be considered only in cases where appropriate corroborating long-term atmospheric exposures have been conducted.

3.3 The reproducibility of results in the salt spray exposure is highly dependent on the type of specimens tested and the evaluation criteria selected, as well as the control of the operating variables. In any testing program, sufficient replicates should be included to establish the variability of the results. Variability has been observed when similar specimens are tested in different fog chambers, even though the testing conditions are nominally similar and within the ranges specified in this practice.

X2. Use of the salt spray (fog) test in research

X2.1 This practice is primarily used for process qualification and quality acceptance. Regarding any new applications it is essential to correlate the results of this practice with actual field exposure results.

X2.2 The salt spray has been used to a considerable extent for the purpose of comparing different materials or finishes. It should be noted there is usually not a direct relation between salt spray (fog) resistance and resistance to corrosion in other media, because the chemistry of the reactions, including the formation of films and their protective value, frequently varies greatly with the precise conditions encountered. Informed personnel are aware of the erratic composition of basic alloys, the possibility of wide variations in the quality and thickness of plated items produced on the same racks at the same time, and the consequent need for a mathematical determination of the number of specimens required to constitute an adequate sample for test purposes. In this connection it is well to point out that Practice B 117 is not applicable to the study or testing of decorative chromium plate (nickel-chromium) on steel or on zinc-base die castings or of cadmium plate on steel. For this purpose Method B 368 and Practice G 85 are available, which are also considered by some to be superior for comparison of chemically treated aluminum (chromated, phosphated, or anodized), although final conclusions regarding the validity of test results related to service experience have not been reached. Practice B 117 and Practice G 85 are considered to be most useful in estimating the relative behavior of closely related materials in marine atmospheres, because they simulate the basic conditions with some acceleration due to either wetness or temperature or both.

ACRONYMS

AHJ	authorities having jurisdiction
ASTM	ASTM International (formerly the American Society for Testing and Materials)
Cr	chromium
CRD	Certification Requirements Decision
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
NEC	National Electrical Code
NRTL	Nationally Recognized Testing Laboratory
OCPD	over-current protection device
PV	photovoltaic
STC	standard test conditions
STP	Standards Technical Panel
UL	Underwriters Laboratories

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Photovoltaic Module Grounding: Issues and Recommendations

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April 2012

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Download a copy of the report:

www.solarabcs.org/grounding

Executive Summary

This is the second and final report of a study addressing the electrical grounding of photovoltaic (PV) modules. The Solar America Board for Codes and Standards (Solar ABCs), with support from the U.S. Department of Energy, commissioned this study to provide the PV industry with practical guidelines and procedures for module grounding in the overall context of system grounding. This report also makes recommendations for improving the technical standards that certify the modules and related grounding components. Solar ABCs published an interim "Lay of the Land" report on the topic in the spring of 2011, which described the many issues facing industry stakeholders. This final report draws on feedback from the PV industry as well as on research performed at Underwriters Laboratories (UL) to develop guidelines and recommend changes to existing codes and standards.

There are two fundamental module grounding issues facing the industry. The first is that there are limited numbers of approved (listed) grounding methods, despite a wide variety of installation methods for grounding module frames. Currently there is much developmental activity on three UL standards that will clarify the listing issue. UL 1703 (Flat-Plate Photovoltaic Modules and Panels) (UL, 2002), the primary governing standard for modules and their grounding, is being revised to make the standard clearer and to provide enhanced testing guidelines. These revisions are not only for module manufacturers—the chief users of the standard—but also for third-party suppliers of grounding components. UL 467 (Grounding and Bonding Equipment) (UL, 2004) as historically been used by some grounding component manufacturers but is not officially recognized as applicable to PV module applications. UL 2703 (Rack Mounting Systems and Clamping Devices for Flat-Plate Photovoltaic Modules and Panels) (UL, 2011) is a draft standard that addresses system level mounting configurations and uses much the same grounding language as UL 1703. The revisions and improvements to these standards are still in progress, but there is clear momentum and direction for resolving the problems that have led to inconsistent understanding and interpretation.

The second issue is the lack of confidence in existing approved grounding methods, due largely to failures in the field from loss of mechanical integrity, installation error, and damage from corrosion. We present details of a recent UL paper (Wang, Yen, Wang, Ji, & Zgonena, 2011), which is included in its entirety as Appendix A. In the study, different types of PV grounding connectors were collected, installed, and tested in accelerated environmental chambers using both continuous damp heat and salt mist environmental exposure. The effects of current cycling, assembly force, and anti-oxidation coating application on grounding reliability were evaluated in conjunction with aging tests.

Under the salt mist condition, most of the samples were severely corroded and failed within weeks, while identical samples in the damp heat chamber were still in good condition. UL is working to determine how these tests should be integrated into UL 1703 and 2703, recognizing that the existing base of standard tests sometimes fails to reveal issues encountered in the field, while extreme laboratory conditions may cause failure modes that will not be seen in actual installations.

> "This report makes recommendations for improving the technical standards that certify the modules and related grounding components."

A UL 1703 subcommittee is investigating the possible adoption of language from an upcoming revision of International Electrotechnical Commission (IEC) 61701 (Edition 2) titled "Salt mist corrosion testing of photovoltaic (PV) modules," which specifically addresses testing issues specific to PV module frames. Solar ABCs will publish an addendum to this report in the spring of 2012 to update industry activities and direction in this area.

Recommended current tests identified in this report mirror the conclusions of a UL 1703 Standards Technical Panel (STP) subcommittee charged with developing new language for the Bonding and Grounding section. These tests combine existing low current tests with tests derived from UL 467 that are designed to ensure proper operation of overcurrent protection devices.

In addition, we consider personnel safety in this report. We explore various fault scenarios in conjunction with IEC data describing body impedances and harmful levels of current to provide generalized methods of evaluating ground resistance limits. We also discuss more generalized design criteria using National Electrical Code principles. From a listing standpoint, the current test regimes recommended here should adequately address safety issues such as touch safe voltages and currents.

UL 1703 and UL 2703 are still undergoing significant change, so this report concludes with general recommendations for ensuring proper grounds based on field experience and feedback received throughout the course of this study.

The general recommendations from this report include:

- Complete the proposed changes to the existing standards to improve the method and quality of ground connections.
- Elicit additional industry feedback from the accelerated aging test study to determine if and how these or similar tests might be incorporated into standard testing.
- Be aware of and make use of the new and expanded set of channels for listing module grounding equipment.
- Be aware of the principles of module frame grounding, the type of faults that may occur, and the implications for safety and ground system design.
- Follow the specific design and installation recommendations enumerated in this report, such as using proper materials and components, following manufacturer instructions, using torque wrenches to ensure proper tightening of connections, and avoiding connections of dissimilar metals that lead to corrosion, among others.

Table of Contents

DISCLAIMER 1

EXECUTIVE SUMMARY 2

AUTHOR BIOGRAPHIES 5

SOLAR AMERICA BOARD FOR CODES AND STANDARDS 5

ACKNOWLEDGEMENT 5

INTRODUCTION 6

- Existing Standards—Summary and Updates 7

RECOMMENDATIONS FOR ENHANCED TESTING 9

- Current Tests 10
- Accelerated Aging and Corrosion Resistance Tests 11

MODULE GROUNDING AND SAFETY UNDER FAULT CONDITIONS 15

- Electricity and the Human Body 15
- Module Frame Fault Scenarios 18
- Implications of a Frame Grounding Approach 21

RECOMMENDATIONS FOR INSTALLATIONS 23

REFERENCES 25

RESOURCES 25

APPENDIX A: Accelerated Aging Tests on PV Grounding Connections 26

ACRONYMS 35

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Solar America Board For Codes And Standards

The Solar America Board for Codes and Standards (Solar ABCs) provides an effective venue for all solar stakeholders. A collaboration of experts formally gathers and prioritizes input from groups such as policy makers, manufacturers, installers, and large- and small-scale consumers to make balanced recommendations to codes and standards organizations for existing and new solar technologies. The U.S. Department of Energy funds Solar ABCs as part of its commitment to facilitate widespread adoption of safe, reliable, and cost-effective solar technologies.

For more information, visit the Solar ABCs website:
www.SolarABCs.org

ACKNOWLEDGEMENT

This material is based upon work supported by the U.S. Department of Energy under Award Number DE-FC36-07GO17034.

INTRODUCTION

This is the final report of a study of photovoltaic (PV) module grounding issues. The need for this study was identified through a gap analysis completed by Solar ABCs with input from many U.S. stakeholders.

PV modules are typically installed on aluminum or galvanized, painted, or stainless steel frame structures. These structures and any other electrically conductive components that could become energized by the PV array (or other electricity sources) and that could be accessible during routine servicing must be bonded to ensure safe touch voltages. In their installation manuals, module manufacturers currently provide detailed directions but limited options for grounding the modules. Other options are available—manufacturers have developed components designed for grounding PV modules and have pursued different approaches for certifying or listing these devices. There is little industry consensus, however, on the appropriateness or completeness of the available standards for these general use components.

The result has been a large number of fielded systems that demonstrate:

- unsatisfactory module grounding measures, broadly characterized as those in which electrical continuity is jeopardized or has failed,
- violations of the module's Underwriters Laboratories Inc. (UL) 1703 listing because the installation does not comply with the installation manual's prescribed method of grounding the module frame,
- incorporation of components listed to more general grounding equipment standards that may or may not be completely suitable for the application, and/or
- well-engineered grounding measures using methods or component systems that together were not listed or had no reasonable process for certification through UL 1703.

The overall module grounding study attempts to address these issues with the following steps:

- Publish an interim Lay of the Land report, a survey of the existing situation in which stakeholders (system designers, module and component manufacturers, Nationally Recognized Testing Laboratories [NRTLs], and researchers) shared their experiences and recommendations to address the issues listed above. This interim report was published in the spring of 2011.
- Evaluate existing and new test procedures. This was primarily a UL-led effort to investigate expanded or enhanced current and accelerated aging test methods that can provide greater confidence in the long-term reliability of grounding methods.
- Develop this final report, incorporating results and feedback from prior efforts. This report makes final recommendations for new or expanded tests to incorporate into standards, and documents guidelines and procedures for public use.

The enhanced accelerated aging test methods are intended to better evaluate the long-term reliability of the connections to and between metal parts in a PV array, applicable to any roof- or ground-mounted system, whether the mounting structure is metallic or not.

This report also provides some practical guidance for system designers, installers, and trainers by describing effective and durable module frame grounds that can be confidently approved by building inspectors and other authorities having jurisdiction (AHJs).

Throughout this document, the terms "ground," "grounding," and "grounded" are used to describe the connections to module frames that are the primary focus of the study.

Note that there is a distinction between "grounded" and "bonded." Article 100 of the 2011 National Electric Code (NEC) (National Electrical Code, 2011) defines these terms as follows:

- Grounded: Connected to ground or to a conducting body that extends the ground connection.
- Bonded: Connected to establish electrical continuity and conductivity.

Much of the scope of this study focuses on the bonding of frames to other parts or conductors that are then grounded. This report uses the more general "grounding" term to describe both bonding and grounding unless bonding is specifically called out.

The topic of PV system grounding covers a wide range of issues outside the scope of this particular study, including the bonding and grounding of support structures and their internal components, system level equipment ground and grounding electrode conductor strategies, lightning protection, grounding of specialized equipment such as alternating current (AC) modules or similarly integrated direct current (DC)/DC converters, and others. Solar ABCs is currently preparing an additional study to address these and other issues.

Existing Standards—Summary and Updates

The standards that address module frame grounding include UL 1703, UL 2703, and UL 467. UL 1703 and UL 2703 in particular are still in a state of development and evolution, and the following is a summary and update of each of these standards.

UL 1703: Flat-Plate Photovoltaic Modules and Panels

UL 1703 is currently the "primary" standard affecting module grounding and devices. Methods certified to UL 1703 and documented in module manufacturers' installation instructions are almost universally accepted by inspectors and AHJs. UL 1703 covers a range of safety and construction related requirements for modules, with a few sections dedicated to frame bonding, grounding, and continuity. It also establishes requirements for the means of grounding as well as continuity requirements subject to applied current and environmental (accelerated life) testing.

As discussed throughout this document, there are significant changes proposed for UL 1703, based on the general consensus of the Standards Technical Panel (STP), a panel of industry experts including manufacturers, researchers, integrators, AHJs, and others. These changes should facilitate the listing of more components and methods with specific or categorized modules. We anticipate that a separate listing for each part in combination with each module frame type will be unnecessary. Instead, it should be possible to define generalized frame characteristics for which third party suppliers can design more generic ground connection solutions. The STP met again in October 2011 and further clarified the impending changes.

UL 467: Grounding and Bonding Equipment

UL 467 is dedicated to grounding and bonding equipment and was widely perceived in the industry to be a good template for certifying third party, general use ground components. As noted in the Lay of the Land report, until recently UL 467 presented problems for the PV industry because it did not specifically address some unique aspects of PV applications. Nevertheless, some manufacturers were listing their PV-specific components to the standard. UL subsequently initiated a certification requirements decision (CRD) for UL 467 to incorporate PV module grounding device requirements, but this turned out to be a temporary measure. By the end of 2011, UL 467 was again inapplicable to PV systems. The consensus within UL was that it is preferable to have all PV grounding related components listed to UL 2703 instead.

UL 2703: Rack Mounting Systems and Clamping Devices for Flat-Plate Photovoltaic Modules and Panels

UL 2703 is a new draft standard, meaning it is not yet an American National Standards Institute (ANSI) standard. It was created to address PV module mounting systems, and covers mechanical and other general issues for mounting systems, including grounding. The grounding section incorporates much of the same language used in UL 1703, applied broadly to the mounting system components. Similarly, anticipated improvements to the requirements and tests in UL 1703 will likely be duplicated in UL 2703. We anticipate that some of the grounding sections in UL 1703 will be removed entirely and will only be included in UL 2703.

It is important to note that UL 2703 enables manufacturers to list individual grounding components independent of the racking certification. There is also a mechanism for establishing subsystem level testing of bonding—tests using multiple modules and components connected together, rather than single connections, for example—and impedance requirements for metal apparatus containing multiple strings of modules. The standard is expected to quantify ampacity and cross sectional area requirements, similar in principle to the approach taken for the listing of cable tray systems.

The development of UL 2703 will be a very significant benefit to the PV industry because it will provide a means to evaluate and certify an intuitive and effective use of structural hardware for grounding purposes. We anticipate that the PV grounding work performed under the UL 1703 and 2703 STPs will be proposed for inclusion into both the International Electrotechnical Commission (IEC) 61730-1 and UL 61730-1: *Photovoltaic (PV) Module Safety Qualification—Part 1: Requirements for Construction* standards.

Recommendations For Enhanced Testing

The two main areas of focus for enhanced testing identified during this study were current testing and accelerated aging or corrosion testing. Groups working in the UL 1703 STP have identified the issues and developed recommendations.

Current Tests

The table below summarizes tests now applied under UL 1703, *Flat-Plate Photovoltaic Modules and Panels* (UL, 2002) for module certification, tests for AC general use components under UL 467, *Grounding and Bonding Equipment* (UL, 2004), and tests derived from UL 1741, *Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resource* (UL, 2010).

	UL 1703	UL 467	UL 1741 (short-term)
Test current	2 x module series fuse rating (e.g. 30A)	Current requirement dependent on ground conductor size, e.g. 750A for #10 AWG	1,000A, e.g. (connected in series with proper rated branch-circuit overcurrent-protective device)
Test duration	Sufficient to measure impedance	4 seconds	Until above overcurrent device clears
Result requirement	Resistance between ground connection and accessible conductive part should be < 0.1 Ohm, repeated after temperature, humidity, and corrosive atmosphere tests	"The fitting shall not crack, break, or melt" Repeated after environmental tests	Resistance between ground connection and accessible conductive part should be < 0.1 Ohm, tested with 25A @ 60 Hz

Key: amperes (A), American wire gauge (AWG), hertz (Hz)

There has been much debate on appropriate current tests in the UL 1703 STP discussions, including at meetings held in 2010 and 2011. The Lay of the Land report also provided details of these discussions, which we summarize here:

- UL 1703 uses a relatively low current test based on the maximum series fuse rating to address the potential current flowing through the bonding path for some period of time before the string fuse would be expected to blow. Low current is representative of anticipated leakage currents that will naturally flow and increase with age (much less than 30A, typically). There are industry experts who stress the importance of this test because it is more representative of the type of current the frames experience over time and therefore better replicates potential failure mechanisms.
- Others contend the higher current tests used in UL 467 or UL 1741 are more appropriate. It is a fact that the grounded frames in a faulted string of modules can experience the full array short-circuit current (limited by ground circuit impedance) briefly before the string fuse blows. A fast test at 1,000A, for example, is not unrealistic considering a 500 kW inverter may have more than 1,300A of short-circuit current available to it. Many in the STP have endorsed the use of such a test to demonstrate the integrity of specific and general use grounding components.
- The general STP consensus is that both tests are important. The subcommittee proposal to the STP endorsed both the low and high current test, and also endorsed the use of a table tying current levels to the size of the equipment grounding conductor, as is incorporated in UL 467.

The specific proposal for changes to UL 1703 addresses the current tests and also how samples are re-tested. The full text is as follows:

25.1 Bonding Path Resistance Test

25.1.1 The resistance between the grounding terminal or lead and any accessible conductive part shall not be more than 0.1 ohm when measured in accordance with 25.2.

25.1.2 A current equal to twice the fuse ampere rating specified in accordance with 47.10 is to be passed between the grounding terminal or lead and the conductive part. The resistance is to be calculated using the voltage drop measured between the grounding terminal or lead and a point within 1/2 in (12.7 mm) of the point of current injection.

25.1.3 If more than one test is needed to evaluate all the paths of conduction between accessible metal parts, there is to be a cooling time of at least 15 min between tests.

25.1.4 The test is to be conducted on three unconditioned samples and after performing the tests described in 35 through 37.

25.2 Testing of Bonding and Grounding Devices

25.2.1 The grounding means under test must be assembled to the frame or other mating component as described in the installation manual. A complete module or panel assembly is not necessary when a fully representative assembly section is used.

25.2.2 Three samples shall be tested to 25.1 (applied to the grounding means) before and after subjecting the samples to 35 (sample 1), 36 (sample 2), and 37 (sample 3), and after performing the 25.2.3 test.

25.2.3 After completing the 25.2.2 tests, subject two of the three test samples of the grounding means to the current specified in Table 11.1 for the time specified in that table. The current shall be based on the largest size of wire for which the grounding means is marked. The third test sample shall be exposed to a current of 5,000 amps through the maximum allowable nonrenewable (i.e. single-use) fuse in accordance with 47.10. For both tests the grounding means shall not crack, break, or melt.

Table 11.1 Equipment grounding and bonding conductor size (copper)

AWG or kcmil	Cross-sectional area (mm^2)	Time (s)	Test current (A)
14 AWG	2.1	4	300
12	3.3	4	470
10	5.3	4	750
8	8.4	4	1,180
6	13.3	6	1,530
4	21.2	6	2,450
3	26.7	6	3,100
2	33.6	6	3,900
1	42.4	6	4,900
1/0	53.5	9	5,050
2/0	67.4	9	6,400
3/0	85.0	9	8,030
4/0	107	9	10,100
250 kcmil	127	9	12,000

Key: American wire gauge (AWG), thousand circular mils (kcmil), square millimeters (mm^2), seconds (s), amperes (A)

Accelerated Aging and Corrosion Resistance Tests

One of the common failure modes of module grounding identified in the Lay of the Land report is corrosion of the bonds and connections. The causes found in the field include improper use of components (dissimilar metals), corrosion from inadvertent contact between parts or loss of protective coatings or layers, and general exposure to more corrosive environments. Although some of the issues can be addressed through training and education on the use of materials, these issues raise the question of how standards might better address the protection of ground connections. UL 1703 (and by extension UL 2703) currently specifies the following tests on ground connection samples, after which the continuity tests must be repeated:

Section 35—Temperature Cycling Test, 200 cycles of various temperature changes from as low as minus 40 to plus 90 Celsius.

Section 36—Humidity Test, 10 cycles of humidity-freezing.

Section 37—Corrosive Atmosphere Test, including salt spray test and moist carbon dioxide/sulphur dioxide test.

It is important to note, however, that the tests in Section 37 are only required for modules with steel frames. This is because the tests themselves are derived from legacy standards applicable to steel equipment. The result is that because almost all module frames are made of aluminum, they are not required to be tested. In an effort to address this gap, UL embarked on a study with exploratory tests to inform future revisions of the standards, and recently published a paper on those findings. The paper is titled "Accelerated Aging Tests on PV Ground Connections," and is included in its entirety as an appendix to this report (Wang et al., 2011).

The study objective was to investigate the long-term effectiveness of different PV grounding devices by measuring the contact resistance at the junction between connectors and aluminum frames under simulated harsh environmental conditions. The connection types included the three most common approaches (and listed methods) used today—copper wire connections via screw/washer/nut assemblies, lay-in lug assemblies, and grounding clips.

Identical sample sets were installed and aged separately using:

- Damp heat aging according to IEC 61215, "Crystalline silicon terrestrial photovoltaic (PV) modules—Design qualification and type approval." This consisted of 85 C ambient temperature and 85% relative humidity for 1,000 hours.
- Salt mist aging according to IEC 60068-2-11, "Basic Environmental Testing Procedures, Part 2: Tests-Test Ka: Salt Mist." This standard compares resistance to deterioration from salt mist between materials of similar construction, and is used to evaluate the quality and the uniformity of protective coatings. The environment consists of continuous fine mist of aerated 3% NaCl solution buffered to a pH of 5.5.

Additionally, certain samples were cycled with current during the tests to simulate typical daily solar profiles. The contact resistance was measured before and after each test for comparison. The table below describes each of the sample types that were tested. The "compound" notation indicates samples that included anti-oxidation coatings on the connections.

Sample Groups and Configurations

(from *Accelerated Aging Tests on PV Grounding Connections* [Wang et al., 2011])

Connectors	Sample nos.	Connector type & installation methods
A	1 (control)	Attaching a tin-plated copper lay-in lug to aluminum frame with a stainless steel (SS) locknut penetrating the aluminum surface
	2 (compound)	
	3 (current)	
B	1 (control)	Removing the anodization on the aluminum frame and then attaching tin-plated copper lay-in lug directly to it; an anti-oxidant compound was applied between the lug and aluminum surface
	2 (compound)	
	3 (current)	
C	1 (control)	Grounding copper wire to aluminum frame using SS thread-cutting screw and SS cup washer
	2 (compound)	
	3 (current)	
D	1 (control)	Attaching a tin-plated lay-in lug to aluminum frame with a teeth washer laid between the lug and aluminum surface (teeth face towards the aluminum surface)
	2 (compound)	
	3 (current)	
E	1 (control)	Using a grounding clips assembly consisting of a slider, base, and SS thread-cutting screw
	2 (compound)	
	3 (current)	

Salient results include:

- In the damp-heat condition, the resistances for all connectors remained low (< 0.05 ohm) and had almost no change over 20 weeks.
- In the salt mist condition, however, most samples corroded severely and failed in weeks, where failure was set at > 10 ohms.
- Samples using the anti-oxidant coating lasted longer before failing.
- The lay-in lug with washer (D) and grounding clips (E) with compound lasted more than 20 weeks in the salt mist condition.

- Current cycling did not have a significant impact on the samples tested under salt mist conditions. Sample D appears to be an exception, but there is insufficient data to conclude that there is a meaningful difference with that method. Speculation is that the accelerated aging under salt mist condition was too severe (and fast-acting) to show the effects of current cycling.
- Proper torque on the connections improved the performance. Connections that were under-torqued failed five times sooner than those that used a torque wrench to achieve the manufacturer specifications. This result clearly underscores the importance of using torque wrenches in the field to ensure properly torqued connections, and of having the proper torque values plainly communicated to installers.

The UL aging paper was released recently and is still being evaluated. A thorough industry review will be important for determining if and how those tests should be applied in standards. Solar ABCs will publish an update of the industry response in the spring of 2012. In the meantime, we include some preliminary feedback here.

Initial recommendations include that there be additional review of the attachment methods by manufacturers of the grounding clips and lay-in lugs. For example, one lay-in lug manufacturer's instructions recommend using a flat washer between any lock or star washer and the lug surface. This is presumably to prevent excessive penetration of the tin plating on the lug and exposure of the underlying copper to galvanic corrosion. A flat washer would also create a firmer surface relative to the soft copper lug and aluminum module surfaces, which can deform under the pressure of a lock washer (Wiles, 2011).

Other questions and suggestions regarding the specific configurations, parts, and scope of the tests include:

- requests for explicit information on the parts and components used in the tests to better understand and qualify the failures;
- suggestions for additional tests, expanded to include other available components that could exhibit different performance characteristics; and
- better characterization of the module anodization thickness, which can vary markedly and may have an impact on testing results.

A few stakeholders (manufacturers and other NRTLs) suggested that the tests were a welcome start and recommended the consideration of additional tests with a wider forum of participation for defining the scope of tests.

It is important to note that the UL aging paper did not state that the salt mist tests as defined by IEC 60068-2-11 should be incorporated into standardized tests for listing purposes. Although it is widely acknowledged that tests need to be more rigorous to help reduce corrosion issues, many in the industry have expressed concern about using a testing approach employing continuous exposure to salt mist. IEC 60068-2-11 and ASTM (formerly American Society for Testing and Materials, now ASTM International) B117 have both been cited and used in component tests, and both prescribe continuous salt mist exposure. The standards aren't significantly different. In general, the IEC testing procedure is broader and the ASTM method is more specific and thorough, describing the parameters of the test and how to measure them in more detail. Some of the specific differences include:

- The IEC test procedure calls for no more than 0.1 % sodium iodide whereas the ASTM standard states that halides including bromide, fluoride, and iodide make up no more than 0.1 %.
- The IEC procedure suggests a water temperature of at least 35°C, whereas the ASTM test procedure suggests a water temperature of 46°C to 49°C to offset the cooling effect of expansion to atmospheric pressure during the atomization process.

- The IEC standard gives no guidelines for positioning the tested component, but states that its position in the test chamber is of prime importance. The ASTM standard recommends that the components be supported or suspended between 15° and 30° from the vertical and parallel to the principal direction of the flow of fog through the chamber.

The Lay of the Land report includes a more detailed discussion of issues specifically concerning the use of ASTM B117, which we repeat here for convenience:

> SunPower in particular provided comments to the STP pointing out that the corrosion mechanisms induced by the B117 tests are known to often differ from those found in the field. Their argument is that the results cannot accurately provide a correlation between the accelerated tests and long-term performance in field conditions, and therefore the potential exists for the industry to chase the wrong problems. The B117 practice itself cautions against the use of the method to predict corrosion performance in the field, and SunPower cites corrosion experts from the auto and electronics industry who have expressed concerns about the use and interpretation of such tests. They stated that in general, the use of accelerated corrosion test procedures that have not demonstrated correlation with performance in natural environments for the materials and physical configurations in question is of limited value and must be interpreted with caution. Attempting to accelerate galvanic corrosion is particularly problematic. For example, the ASTM reference on corrosion tests and standards states "Accelerated testing to get a result in a shorter time period than would be possible naturally should be avoided whenever possible, because the mechanism of galvanic corrosion can change if the rate is altered significantly." (Baboian, 2005).

Actual installations exist in a wide range of environments and these particular tests may only be truly pertinent for the more punishing marine environments. Coastal industrial areas, for example, may have combined high humidity and chemical content, and acid rain may be a contributing factor in areas with high rainfall.

A UL 1703 STP subcommittee has been formed to pursue this topic and develop a proposal for revisions, which will most likely be incorporated in UL 2703 as well. One promising development likely to inform these changes is a pending revision to IEC 61701 (Edition 2), "Salt mist corrosion testing of photovoltaic (PV) modules." The revision departs from IEC 60068-2-11 and instead derives more from IEC 60068-2-52, which is widely used in the electronic component field. The tests also better reflect field conditions. For example, the modules are exposed to cycles of alternating salt fog and humidity rather than continuous salt fog. The subcommittee will most likely recommend that some variation of the testing defined in IEC 61701 be used to replace the existing contents of Section 37 in UL 1703. Solar ABCs will publish a brief follow-up report on this activity in the coming year.

"The UL aging paper was released recently and is still being evaluated."

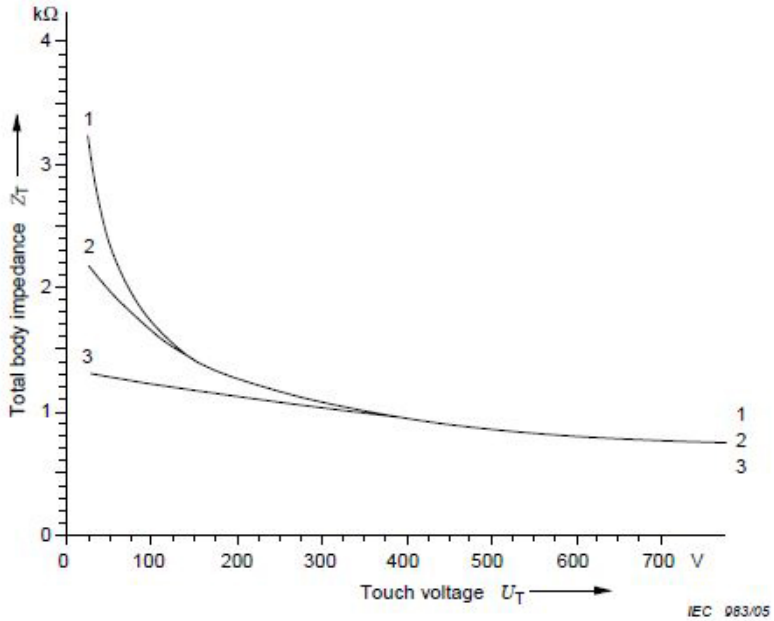
MODULE GROUNDING AND SAFETY UNDER FAULT CONDITIONS

This section focuses on background material to be used as the basis for module grounding and the design of safe systems. The section reviews basic concepts of the impact of electricity on the human body and by extension the potential danger to personnel presented by improperly grounded module frames. We then look at module frame fault scenarios. An analysis of these types of faults provides guidance for determining adequate conductivity of the grounding system and adequate performance of frame connections that carry fault current. Finally, we discuss systemic methods of module grounding and how well they address safety in the event of the faults.

ELECTRICITY AND THE HUMAN BODY

There are several references on body resistance and the levels of current that cause harm to humans. IEC standard 60479-1 (IEC, 2005), for example, defines typical body impedances as a function of voltage, contact area, contact points, conditions (wet, dry) of skin, and percentiles of population.

Figure 1 shows the impedance as a function of voltage for low frequency AC (50/60 hertz [hz]), from hand-to-hand, under dry, wet, and saltwater wet conditions. The curves are representative of the 50th percentile of the population, meaning 50% of the population's body impedance is at these or lower values.



Key

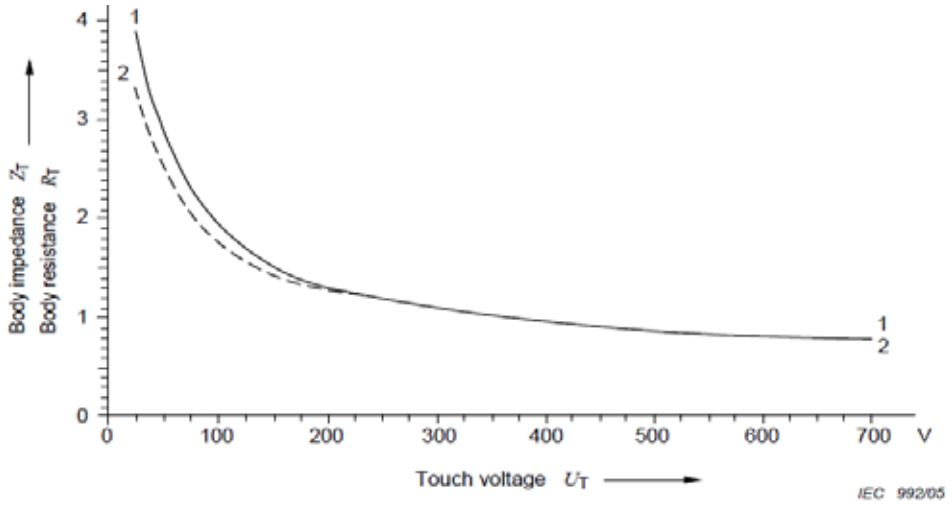
1 dry conditions
2 water-wet conditions
3 saltwater-wet conditions

Figure 1: Total Body Impedances for a Current Path of Hand-to-Hand for a Percentile Rank of 50% of the Population (50/60 Hz AC) (IEC, 2005)

Figure 2 shows a similar chart comparing the body impedances for DC and AC voltages, under dry conditions. DC resistances tend to be higher at lower voltages, but are similar to AC resistances. Below 200V, the DC resistance is higher due to the blocking effect of the skin capacitances.

The two charts together indicate that the dry, wet, and saltwater wet conditions of the AC case apply reasonably well to DC voltage conditions.

This chart is also representative of the 50th percentile rank of the population. Note that UL typically uses the more conservative 5th percentile values to address shock issues. Using the 5th percentile values for safety measures effectively means that 95% of the population is protected.



Key

1 body resistance R_T for d.c.
2 body impedance Z_T for a.c. 50 Hz

Figure 2: Total Body Impedances for a Current Path of Hand-to-Hand for a Percentile Rank of 50% of the Population (AC vs. DC) (IEC, 2005)

The table below from IEC 60479-1 (IEC, 2005) shows the DC resistance values for 5%, 50%, and 95% of the population. The 50% values correspond to the chart in Figure 3, and the 5% values are those used by UL.

Total Body Resistances for a Current Path Hand-to-Hand, DC, for Large Surface Areas of Contact in Dry Conditions
(from Table 10, IEC 60479-1 [IEC, 2005])

Touch voltage V	Values for the total body resistance RT (ohm) that are not exceeded for		
	5% of the population	50% of the population	95% of the population
25	2,100	3,875	7,275
50	1,600	2,900	5,325
75	1,275	2,275	4,100
100	1,100	1,900	3,350
125	975	1,675	2,875
150	875	1,475	2,475
175	825	1,350	2,225
200	800	1,275	2,050
225	775	1,225	1,900
400	700	950	1,275
500	625	850	1,150

Touch voltage V	Values for the total body resistance RT (ohm) that are not exceeded for		
	5% of the population	50% of the population	95% of the population
700	575	775	1,050
1,000	575	775	1,050
Asymptotic value	575	775	1,050

The various sources indicate that the body is somewhat more tolerant of DC than AC voltage shocks. IEC 60479-1 (IEC, 2005) states that harmful accidents with DC systems are much less frequent than would be expected given the proportional number of DC and AC systems that exist. This is in part due to the fact that it is easier to let go of DC than AC live parts, and "for shock durations longer than the period of the cardiac cycle, the threshold of ventricular fibrillation is considerably higher than for alternating current."

Figure 3 shows time current zones of DC current and its impact on the body. Zones DC3 and DC4 are levels that are potentially harmful or fatal, whereas the Zones DC 1 and DC 2 have different levels of feel and reaction but generally do not cause physiological damage. The DC3 zone begins at curve "b" and above. Curves c1, c2, and c3 are representative of current magnitudes and durations at which the probabilities of ventricular fibrillation increase respectively for the population. Curves c2 and c3 represent 5% and 50% of the population. Values below the c1 curve are thought to be conservative for all humans.

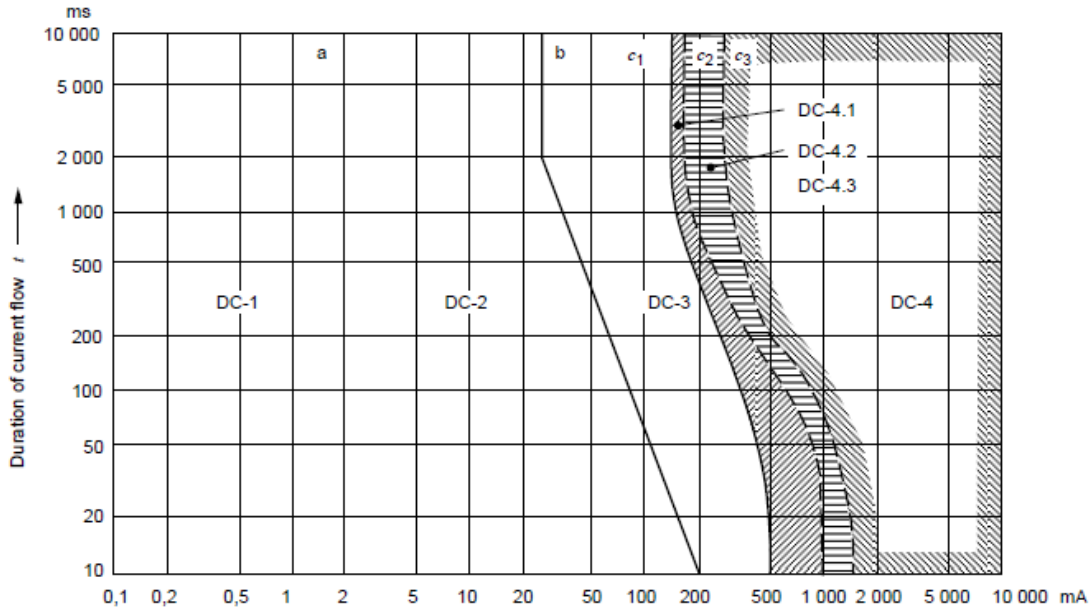


Figure 3: DC Time-Current Curves and Zones Defining the Typical Impact on Human Beings (IEC, 2005)

UL uses a specific set of tables from a 1999 Electric Power Research Institute report as the basis for current thresholds used in its safety standards (UL, 1999).

The two tables below show these DC and AC current limits as a function of the physiological effects caused in humans in general, and those restricted to adults only.

DC Current Thresholds for Various Physiological Effects in Humans (UL, 1999)

Physiological effect	Ordinary DC limit	DC limits for situations restricted to adults only
Startle reaction	2.0 mA	2.0 mA
Inability to let go	30 mA	40 mA
Ventricular fibrillation	80 mA	240 mA
Electrical burns	70 mA	70 mA

Key: milliampere (mA)

AC Current Thresholds for Various Physiological Effects in Humans (UL, 1999)

Physiological effect	Ordinary 60-Hz limit	60-Hz limits for situations restricted to adults only
Startle reaction	0.5 mA	0.5 mA
Inability to let go	5.0 mA	6.0 mA
Ventricular fibrillation	20 mA	105 mA
Electrical burns	70 mA	70 mA

Key: milliampere (mA), hertz (Hz)

Module Frame Fault Scenarios

The following is a brief review of module frame fault scenarios that can impact personnel safety from the standpoint of touch safe voltages or currents. An analysis of these types of faults provides guidance for determining adequate conductivity of the grounding system and adequate performance of frame connections that carry fault current.

Article 250.4(A) of the NEC, "General Requirements for Grounding and Bonding," states that for grounded systems equipment such as module frames "shall be connected together and to the supply source in a manner that establishes an effective ground-fault current path" [250.4(A)(3)]. An effective ground-fault current path is electrical equipment and wiring that "shall be installed in a manner that creates a low-impedance circuit facilitating the operation of the overcurrent device," and "shall be capable of carrying the maximum fault current likely to be imposed on it..." [250.4(A)(5)]. Similar language is provided for ungrounded systems in 250.4(B). Fault scenarios that cause current to flow through the frames include:

- lightning,
- ground faults (live DC circuit connection to the frames),
- leakage current, and
- faults from external sources, such as an AC circuit with wiring adjacent to the PV system hardware.

A person who makes contact with a conductive surface such as a module frame when it is not properly grounded can be exposed to a dangerous voltage. We do not address the lightning scenario in this report because of the complex system level grounding factors involved. Lightning protection is a serious issue for PV systems, and should be addressed as appropriate using NFPA 780 or other guidelines targeting PV systems specifically.

Faults from external sources such as AC systems have been uncommon to date. As the number of AC module and microinverter applications increases, however, it is inevitable that AC conductor faults will occur on module frames. These faults can have higher current levels even on very small systems because they are sourced by the utility supply, not the current-limited PV array. We will not address AC ground faults separately here because they are similar to DC ground faults with respect to the effective bonding and grounding of module frames.

Presently the two module frame fault scenarios most likely to present a potential shock or safety hazard are the DC circuit ground fault and leakage current. The discussions here center around module frames, but these faults can also occur on other conductive surfaces that rely on the module frame for a conductive path to the ground circuit—an isolated mounting clip, for example.

Conductor Fault to Frame

On a grounded DC system, a short-circuit fault will occur if a damaged ungrounded string conductor is exposed and electrically connected to a module frame. For example, if the PV system has a negative-grounded circuit (the most common design in the United States today), a short of the positive conductor to a frame will create a direct connection between the array positive and negative circuit. Figure 4 shows a diagram of this ground fault example. As indicated by the red arrows in the figure, the path of the fault current is from the:

- exposed positive polarity conductor to the module frame,
- module frame to the ground circuit (equipment grounding conductor),
- equipment grounding conductor to the inverter ground bus,
- inverter ground bus to the inverter negative bus (location of negative to ground bond through the ground fault detector interrupter [GFDI]), and
- negative ground bus to the negative conductor of the faulted string.

As the figure shows, however, the fault current is not limited to the single faulted string. The entire array positive pole is grounded via this connection to the frame, so most of the fault current is backfed from the positive bus at the combiner box and the recombining fuse bridge feeding the inverter. These currents will flow through this fault connection until either the GFDI or the faulted string fuse operates.

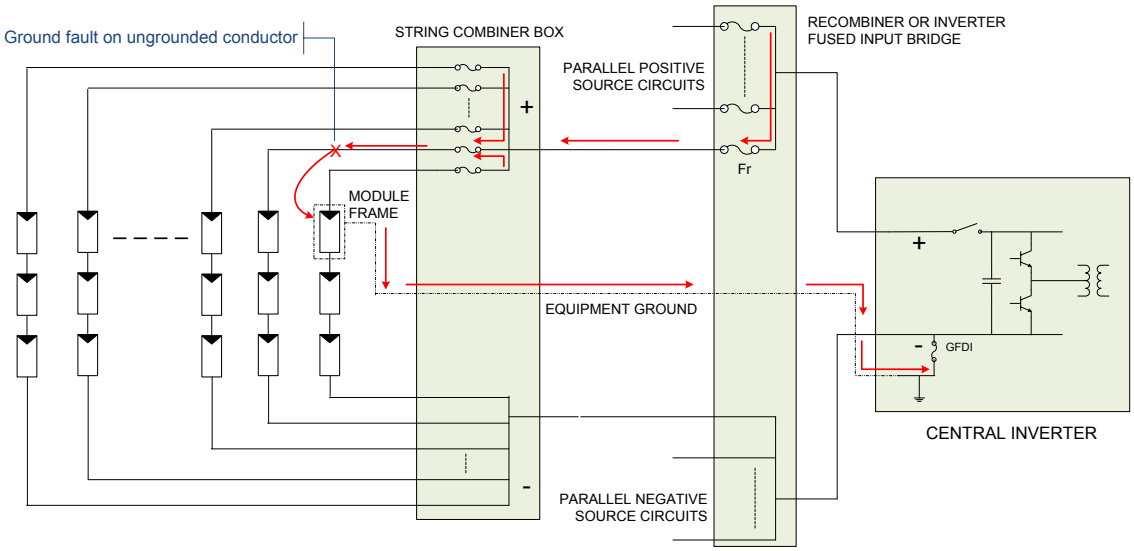


Figure 4: Representation of a DC Ground Fault to a Module Frame

Most systems installed in the United States today incorporate GFDI circuits in the inverter. Most of these GDFI circuits interrupt the fault current using fuses or other overcurrent protection devices (OCPD) ranging from 1A to 5A, depending on the size of the inverter. So for most arrays, a hard (or low impedance) fault between the positive pole circuit (conductor) and ground (module frame) will cause the GFDI to operate, isolate the fault, and stop fault current.

This fault condition would also typically cause the faulted string fuse to blow, due to the same (entire) array current circulating through that single fuse to the fault point. With string fuse ratings typically between 5A and 15A, the GFDI is likely to interrupt first. Systems without GFDI rely on the string fuse, which interrupts current from the rest of the array but does not stop the circulating fault current of the one faulted string.

A DC ground fault may not trigger the OCPD if the fault is a high-impedance or weak connection or if the irradiance is low. Any factor limiting the current in the fault circuit will prevent or delay OCPD operation, including resistance in the ground path from module frames to the ground circuit.

Leakage Current to Frame

Leakage current in grounded PV systems is an unavoidable phenomenon involving very small amounts of current "leaking" from the cells to the module frames, typically via the module glass. Assuming the frame is properly grounded, the leakage current travels from the frame to the ground circuit and returns via the grounded polarity conductor to the modules.

Under normal conditions, there is no safety hazard. The PV frame is maintained at ground potential by the NEC-required ground connection for accessible unenergized metal and therefore does not attain a hazardous touch voltage relative to other grounded metal or to earth. If the frame has a poor or discontinuous ground connection, however, the frame voltage relative to earth potential can be significant (especially on a high voltage PV array) and a person touching the frame can become the path for the leakage current. Again, under normal operating conditions, even this event would most likely not be dangerous. However, abnormal leakage currents to frame on a big system (for example, caused by aging or defective PV modules with broken glass or delamination, and made worse by wet conditions) could cause enough of a voltage potential and energy to injure or kill anyone who contacts the ungrounded PV module frame.

A "worst-case" scenario related to module frames occurs when a person is the only path for potentially high ground fault current. For example, if there was a conductor to frame fault (as described in the section above) and the frame had no ground connection, a person touching the frame would experience the same shock as if he touched the live wire.

If the module frame has a poor, high impedance ground connection, the person touching the frame becomes an alternate parallel path for ground current to flow. A spectrum of variables determines whether that person would be injured by electrical shock, including the:

- impedance in the frame-ground circuit (it must be high enough that there is insufficient fault current to operate the GFDI);
- size of the array (it must be large enough to maintain a dangerous voltage on the frame before and after the person touches it);
- resistance of the person's body (as discussed earlier); and
- resistance between the body and the return path to ground, which can be through the earth or other grounded metal such as an adjacent PV module or mounting frame.

Overall, the strength of the power source determines the voltage and current characteristics when applied through a specific impedance, and the impedance of the equipment ground circuit determines how much of the fault current can be diverted through a person's body. A deeper analysis of these phenomena using array simulation models such as PSPICE would be useful, but is beyond the scope of this study.

Implications of Frame Grounding Approach

From a practical standpoint, the goal should be to determine the maximum allowable resistances in the equipment grounding circuit to keep voltage differences sufficiently low and fault current path capabilities sufficiently high. To address these questions, it is helpful to summarize three different module grounding scenarios and identify issues that need more attention.

Frames Bonded to Conductor or Structural Equipment Grounding Conductor

Module frames in a contiguous row are bonded to an equipment grounding conductor (ECG)—copper wire, for example—using standard methods (ground holes, nut/bolt assembly, or lay-in lug). Or, the module frames are bonded to an EGC equivalent, such as a mounting bar or tracker torque tube, using a tested (listed) method. In either case, the primary if not only ground current path is through the conductor. Parallel paths may exist via conductive mounting hardware, but personnel safety does not depend upon them.

Frames Bonded Directly or Indirectly to Other Module Frames With a Single Ground Circuit Path

In this case, module frames in a contiguous row are bonded sequentially to each other, via a clip or equivalent, so that the ground current path is primarily if not only through the frames themselves. Parallel paths may exist via conductive mounting hardware, but personnel safety does not depend upon them.

Frames Bonded Directly or Indirectly to Other Module Frames With Multiple Ground Circuit Paths

In this case, module frames in multiple contiguous rows are bonded to each other creating multiple intended paths, via the mounting structure or multiple clip connections. An example might be a rooftop system using multiple clips to secure modules to each other or to clamps that secure the modules to a metallic racking system. With so many connection points from module to module and other mounting hardware, the array is effectively a contiguous sheet with very low ground resistance paths.

Of these three scenarios, the second is of greatest concern or interest because of the number of frames and connections between the frames that are in the path of any array ground faults. If there are 30 contiguous modules connected together mechanically, each with 0.1 ohm connections to the next module (as permitted by UL 1703), there is now a 3 ohm ground path between the first module and an actual EGC. A person is not able to reach across such a great distance, but it is feasible that someone could be standing by a combiner box and a module that is electrically distant from that box. The impedance between the combiner box and the module might present a problem if the person touches both.

Elaborating on this example, consider the case of a high impedance fault that exists between a module frame and ground and causes 6A of current to flow through the module frames on the ground circuit. The 5A GFDI fuse in the inverter is “seeing” this current, but will not operate for some time. If the resistance of the module frame/connection path is 10 ohms, there will be a 60V difference between the combiner box enclosure and the module frame. A person touching both presents a 1,000 ohm parallel path for the ground current between the frame and the combiner box, therefore passing as much as 60 milliamperes (mA) through the body. While likely not fatal, this would be an unacceptable hazard.

To establish an example for minimum ground circuit resistance, assume a:

- design fault current of 15A (15A through a 5A OCPD would trip in less than a minute),
- low order body resistance of 1kohm, and
- maximum allowable fault current through the body of 30 mA.

In this example, the touch voltage would need to exceed 30mA*1kohm or 30V to cause 30mA through the body. This means the ground circuit resistance between two objects accessible to the person cannot exceed 2 ohms (30V/15A).

A maximum ground circuit resistance value clearly cannot be easily generalized, but one lesson to learn from these examples is the importance of minimizing the electrical distance between two physical objects accessible to a person. Using the grounding approaches as defined in the first and third scenarios will provide the greatest assurance by limiting the reliance on module frames and their connectors for a path of any distance.

Another way to evaluate the overall ground path resistance is to compare it to the resistance of EGCs as sized in the NEC:

> Article 250.4
> (A) Grounded Systems
> (3) Bonding of Electrical Equipment. Normally non-current-carrying conductive materials enclosing electrical conductors or equipment, or forming part of such equipment, shall be connected together and to the electrical supply source in a manner that establishes an effective ground-fault current path.
>
> (5) Effective Ground-Fault Current Path. Electrical equipment and wiring and other electrically conductive material likely to become energized shall be installed in a manner that creates a low-impedance circuit facilitating the operation of the overcurrent device or ground detector for high-impedance grounded systems. It shall be capable of safely carrying the maximum ground-fault current likely to be imposed on it from any point on the wiring system where a ground fault may occur to the electrical supply source. The earth shall not be considered as an effective ground-fault current path.

NEC Table 250.122 determines the minimum EGC sized for circuits protected by OCPDs. The smallest conductor in the table applies to 15A OCPDs and is a #14 AWG wire. If conservatively applied (maximum GFDIs are 5A OCPDs), the grounding circuit could be based on the equivalent resistance of the #14 gauge wire, which is 3 ohms per 1,000 feet.

UL is also exploring the issue of how to define listing criteria at the module level when unknown numbers of panels bonded electrically in series are possible. The industry should expect more information to come as Standards 1703 and 2703 are further developed.

Recommendations for Installations

The interim Lay of the Land report identified numerous causes of inadequate module ground connections. Failed connections were broadly defined as those no longer capable of reliably providing sufficient and appropriate electrical continuity between components. Many of the failure modes fall under the category of design or installation error, which can and should be avoided regardless of the status of listing standards.

Designers and installers therefore should minimize the avoidable problems by following these guidelines:

- Only install PV modules per the manufacturer's installation instructions.
- Only use the grounding methods provided with the PV module or referenced in the module's instruction manual. (Unfortunately, in a few cases grounding instructions have not been recently reviewed by the listing NRTL and do not comply with current UL 1703 grounding requirements. This is hopefully only a temporary problem. Designers and installers familiar with the standards should look for such discrepancies and alert module manufacturers when appropriate.)
- Prevent loosened connections by using proper split washers or equivalent means.
- Use torque wrenches to ensure bolted or screwed connections are not under- or over-torqued. Module frames are relatively thin and it is easy to over-torque and strip a connection. Under-torqued connections may not adequately pierce the anodization or other frame coating. Furthermore, the accelerated aging tests documented in this report demonstrated that under-torqued connections can accelerate corrosion significantly. Always follow equipment instructions for the proper torque values.
- Use care and caution working with and around the ground conductors or equivalent EGCs after bonding the module frame, to minimize stressing the connections during construction. It is not uncommon to see rough handling of modules and mounting hardware, particularly on larger systems.
- Take care to achieve the proper orientation and alignment when drilling into the frame or bolting a connection per the module manufacturer's installation instructions.
- Take the time to ensure the washer/nut combination or assemblies are correctly specified for the module (in this case from the module installation manuals) to achieve a durably tight connection. "Minor" changes to the materials, size, thread-count, diameter, etc., can easily lead to failed connections on a systemic level.
    - On a related note, John Wiles of New Mexico State University recommends that the industry move away from allowing mechanical fasteners to be part of the conductive path in the ground connection. Mechanical fasteners (usually stainless steel) are not generally used to carry electrical power except in devices that have been tested and listed for that use. Instead, the mechanical fasteners are used to bring the electrically conductive surfaces together. Yet many module installation manuals prescribe the use of the stainless steel flat washers as a barrier between an aluminum frame and other conducting body, making the stainless steel fasteners an integral part of the current conducting path. Wiles also suggests that the module manufacturers make their modules with a copper-compatible grounding lead or grounding terminal as one manufacturer did years ago. These subjects should be addressed further.
- Do not allow continual stressing of a connection post-installation by applying more tension on the ground wire or force on the assembly than it can reliably endure. An example is a ground cable pulled so tight that it compromises the assembly or the frame itself.

- Avoid repeated installation of self-drilling or thread-forming machine screws. Get it right the first time. Normal threaded fasteners are tested to ensure that repetitive use will not damage the threads (the CRD that UL issued for UL 1703 requires installing and removing threaded fasteners ten times). Self-drilling or thread-forming machine screws are not intended for repetitive use, however, and are likely to score or wear the existing threads.
- Ensure that components designed to pierce the module coatings, such as star washers or serrated screwheads are selected and installed properly. This extends to ensuring that the sharp edges of the washer face the correct direction (if it is not symmetrically designed), and that it is part of the turning assembly during tightening.
- Ensure the selection of materials for the bonded connection so that these do not cause corrosion. Direct copper and aluminum bonds (without a galvanically compatible surface barrier) are the most common dissimilar metal combination leading to destructive corrosion in PV systems.
- Limit the proximity of the dissimilar metals to each other, such as a copper ground wire running adjacent to and touching the module frames. Over time there can be corrosion when the equipment increases contact by exposure to water, soil, or other conductive debris elements. This corrosion may only be an aesthetic issue, but it is still good practice to limit this exposure where possible.
- In highly corrosive environments—close to seawater, for example—best practice may also include the use of a protective coating such as an anti-oxidant compound on the connection to extend the useful life of the bond. Even with these added measures, ongoing and preventative maintenance could also be required in these environments to keep the contact resistance low.

  One proposal described in the Lay of the Land report was to simplify the list of allowed materials used for grounding devices and mounting means. This was an alternative to defining acceptable combinations as any whose combined electrochemical potential is less than 0.6V. While the specifics of these requirements and conditions are defined, we recommend this minimalist list. Grounding devices and mounting means shall be constructed of:

  - copper or a copper alloy containing not less than 80% copper, which may be coated or plated to avoid galvanic corrosion;
  - stainless steel containing a minimum of 16% chromium (Cr) or 5000 or 6000 series aluminum alloys; or
  - carbon steel, which may be coated or plated to avoid corrosion.

We propose an explicit requirement that there be "no direct contact between different metals that may exhibit galvanic corrosion in atmospheric environments either between parts within the grounding device, or when the device is attached as specified to the accessible conductive part." The acceptable combinations include any combination of:

- 5000 or 6000 series aluminum alloys and commercially pure aluminum,
- stainless steel containing a minimum of 16% Cr,
- nickel,
- tin,
- zinc, and
- zinc-aluminum alloys.

These material combinations are galvanically compatible in almost all service environments. However, platings or coatings must be of sufficient thickness and quality to withstand the service environment for the service life in order to provide an effective buffer layer. Compliance of platings or coatings is unknown, so such combinations need to be verified through the UL 1703 or UL 467 test programs to confirm they will operate as intended.

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Appendix A: Accelerated Aging Tests on PV Grounding Connections

Presented at the IEEE 37th Photovoltaic Specialist Conference, June 2011

Accelerated Aging Tests on PV Grounding Connections

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Abstract: As many contemporary Photovoltaic (PV) Power systems being installed are designed to produce significant amount of electricity and claimed to operate for 25 years or more, appropriate grounding on PV modules to reduce or eliminate shock and fire hazards becomes a critical issue under high electricity output and long-term use. Although some PV manufacturers have provided technical bulletins to suggest grounding products and methods, not all of them have been carefully evaluated and reviewed by the certification/listing laboratories. In this paper, different types of PV grounding connectors were collected, installed and put into accelerated environmental test chambers. The effects of current cycling, assembly force, anti-oxidation coating application on grounding reliability were evaluated. The grounding failure modes and mechanisms are also discussed in this paper.

Keywords: PV grounding, electrical shock, accelerated aging, salt mist, galvanic corrosion, dissimilar metal

INTRODUCTION

Photovoltaic (PV) power systems being installed today are normally designed to produce significant amounts of electricity over an expected operating life of more than 25 years. The high electrical output and long-term reliable performance necessitate robust grounding systems for PV systems to minimize accidental electric shock and fire hazards.

In late 2007, UL issued an Interpretation of UL 1703 on the topic of module field grounding. The Interpretation clarified that the module instruction manual must specify the grounding methods and materials to be used for external field-made grounding connections. These methods and materials are evaluated as part of the module Listing process and will apply to all existing Listed modules and their instructions as they come up for review. [1].

A good connection between the grounding hardware and the module frame is essential for a grounding system to function properly. Typically PV manufacturers use copper-alloy for electrical connections and aluminum-alloy for the module frames. The anodization on the aluminum-alloy surfaces is able to provide an oxidized layer to minimize further corrosion of the frames. However, while the anodization of the aluminum-alloy surfaces creates an oxidized layer that minimizes frame corrosion, it also generates a high electrical resistance reducing grounding effectiveness. To overcome this design issue, the grounding hardware must penetrate through the anodization layer to create a direct electric connection. This is normally achieved by one of the following approaches: (1) Installing a self-tapping or self-drilling fastener through the frame, (2) using a stainless steel star (toothed) washer held against the frame by a bolt or nut, or (3) attaching a Listed lug (see figure 1) to the marked grounding points after appropriate surface preparation has been accomplished. [2] [3]

The differences in these grounding approaches may result in significant performance differences over the course of the product service life. Therefore further study is needed to address the long-term effect and reliability of these different grounding installations.

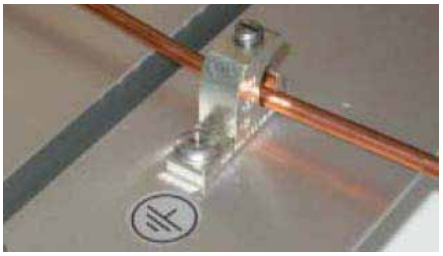


Figure 1 Lay-in lug Listed for direct burial (DB) and outdoor use

OBJECTIVE

The objective of this study is to investigate the long-term effectiveness of different PV grounding devices under simulated harsh environmental conditions. By measuring the contact resistance at the junction between connectors and aluminum frames, this scope of this study includes examining the following grounding techniques:

- Attaching lay-in lug to aluminum frame with a lock-nut penetrating the aluminum surface.
- Removing anodization on the aluminum frame and then attaching lay-in lug directly to it. An anti-oxidant compound was applied between the lug and aluminum surface.
- Grounding copper wire to aluminum frame using thread-cutting screw and cup washer.
- Attaching lay-in lug to aluminum frame with a teeth washer laid between the lug and aluminum surface
- Using grounding clips assembly consists of a slider, base, and thread-cutting screw.

In order to understand the possible corrosion effect caused by current, this study also compared the effectiveness of grounding technique with and without current.

The connectors, copper conductors, and anti-oxidant compound used in this study were all commercially available varieties obtained from different manufacturers. Manufacturers' names are omitted from this paper since the intention of this study was not to compare specific manufacturer's products.

TEST DESIGN

Different types of connectors were installed according to the instructions provided by the manufacturers, including the aluminum surface preparation, applying anti-oxidation coating and the torque requirements. A DC power supply with current and voltage limiting functions was used for current cycling. As shown in Table 1, different groups of connectors from different manufacturers were put in series and each group has 3 samples labeled as Sample No. '1' (control sample), '2' (with anti-oxidation compound) and '3'(with current cycling) for comparison purpose. The aluminum frames were cut to the length of 10cm and identical pairs of connectors were installed at the frames. With this set-up, supplied current can flow in to one connector and out from the other.

Identical sample sets were installed and aged separately under the following two conditions:

1. Continuous salt mist spray, consisting of a fine mist of aerated 3% NaCl solution buffer to a pH of 5.5. [4]
2. 85°C ambient temperature and 85% relative humidity. [5]

This was intended to produce conditions in which connectors that are susceptible to corrosion will show increased contact resistance over time. A 5 amps electrical current was cycled on and off on certain samples to simulate solar day current flow variations. For the resistance measurement, all contact resistances were measured at room temperature using a micro-ohm meter from a terminal block placed out of the chambers. Copper conductor wires were connected and fixed at the block as shown in Figure 2.

Table 1 Sample groups and configurations

Connectors	Sample Nos.	Connector type & Installation methods
	1 (control)	Attaching a tin-plated copper lay-in lug to aluminum frame with a SS lock-nut penetrating the aluminum surface.
A	2 (compound)	
	3 (current)	
	1(control)	Removing the anodization on the aluminum frame and then attaching tin-plated copper lay-in lug directly to it. An anti-oxidant compound was applied between the lug and aluminum surface. (B-2 is the NEC suggested structure)
	2 (compound)	
B	3 (current)	
	1(control)	Grounding copper wire to aluminum frame using SS thread-cutting screw and SS cup washer.
C	2 (compound)	
	3 (current)	
	1(control)	Attaching a tin-plated lay-in lug to aluminum frame with a teeth washer laid between the lug and aluminum surface (Teeth face towards the Al surface)
D	2 (compound)	
	3 (current)	
	1(control)	Using grounding clips assembly consists of a slider, base, and SS thread-cutting screw.
E	2 (compound)	
	3 (current)	

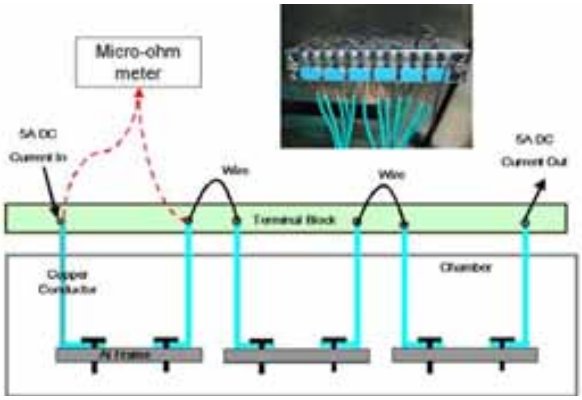


Figure 2 Sample layout for the corrosion cycling

TEST RESULTS

A. Damp Heat Aging

Connector groups C, D and E were selected for damp heat aging study. The sample connectors were jointed together in series and subjected to continuous damp heat aging at 85°C ambient temperature and 85% relative humidity. The resistances of all connectors were measured every week at the same temperature level. Data (Figure. 3) shows that the resistances for all connectors remained in low level ($< 0.05\Omega$) and had almost no change over 20 weeks, which indicated that the connectors were still in good condition and making consistent connection. A resistance pulse at the 2nd week was found due to the abnormality of the ohmmeter. The meter got back to normal after that week. The experiment was terminated at the 21st week, as it's believed that in short-term, continuous damp heat aging would not have any effects on the grounding integrity.

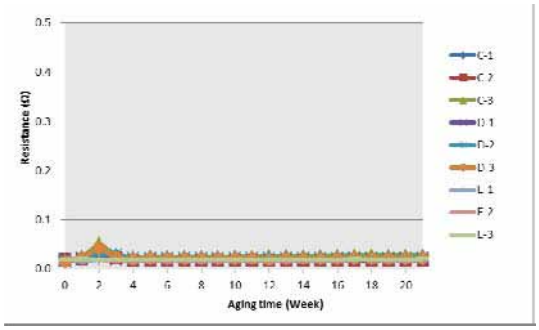


Figure 3 Resistance measurements for group C, D and E connectors under damp heat aging

B. Salt mist Aging

Comparing to damp heat, salt mist condition was a much more severe atmosphere for the grounding connectors. All of the connectors (group A, B, C, D and E) were aged under salt mist condition and the resistances were measured on every individual weekly until it is failed (defined as $> 10\Omega$). The resistance measurements data for No.1, No.2 and No.3 connectors are shown in Figure 4 to 6. And Figure 7 shows the failure time data of all connectors. As the figures show, some connectors became unstable and failed in a couple of weeks while some of the others had survived for more than 20 week. According to the data, group D connectors performed the best among all connectors.

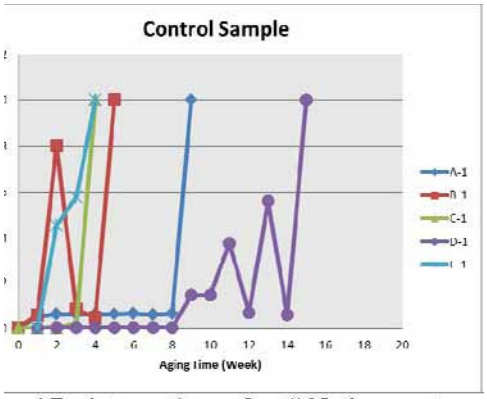


Figure 4 Resistance change for all No.1 connectors under salt mist aging

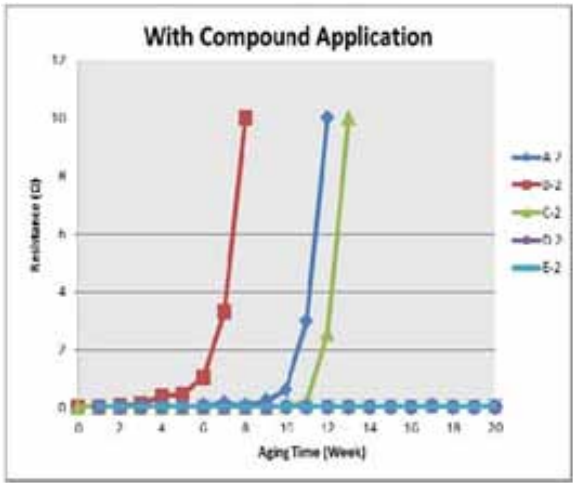


Figure 5 Resistance change for all No.2 connectors under salt mist aging

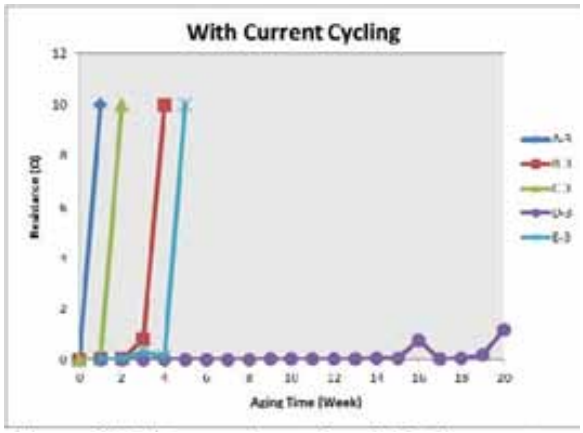


Figure 6 Resistance change for all No.3 connectors under salt mist aging

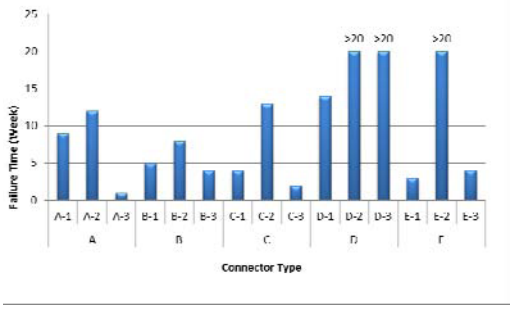


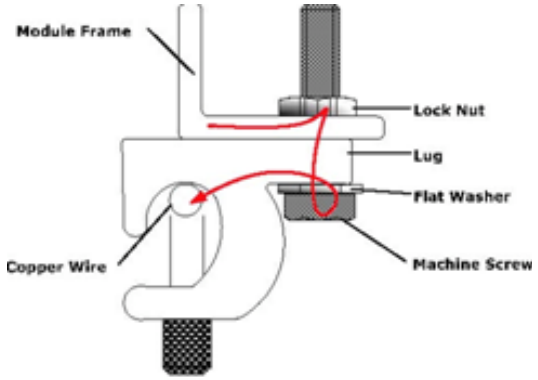
Figure 7 Failure time analysis for all connectors under salt mist aging

Discussion

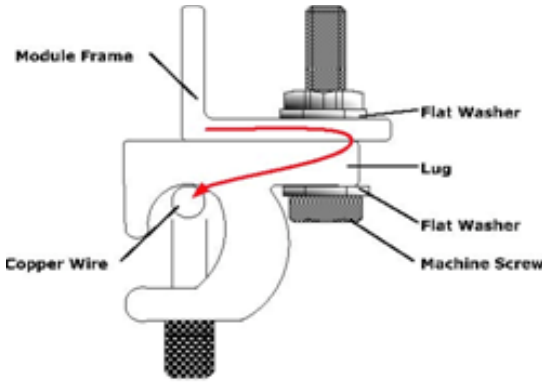
A. Conducting Paths

Although there are different grounding connectors from different manufacturers, there are mainly three conducting paths for all grounding connections. The first one uses the teeth washer or lock nut as a conducting part; the second one uses the grounding lug itself as a conducting part and the last one uses the self-taping screw. Below are the diagrams of the conducting paths:

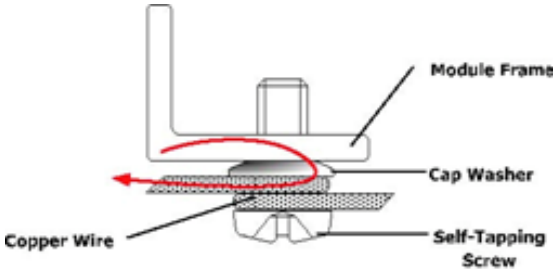
1.) Leakage Current→Aluminum Frame→Lock nut→Machine Screw→Flat washer→Lug→Copper Wire→Ground



2.) Leakage Current→Anodization-removed Aluminum Frame→ →Lug→Copper Wire→Ground



3.) Leakage Current→Aluminum Frame→Self-Tapping Screw→Copper Wire→Ground



B. Anti-oxidant Compound Application

Anti-oxidant compound we used in the research is UL Listed and recommended for all voltages and consists of non-petroleum base vehicle in which zinc particles are suspended. The compound was applied to the No.2 samples in all groups (A-2, B-2, C-2, D-2 and E-2). It was applied on the conductive surfaces of the connector components such as screw threads, copper wire, grounding lugs and the aluminum surface. The data in Figure 5 shows that the samples with anti-oxidant compound applied survived longer than the samples without it.

C. Current Cycling Test

The reason for conducting current cycling was to simulate solar day current flow variations and encourage corrosions at the connectors. For the test, a 5 Amps electric current was cycled on and off on No.3 connectors (A-3, B-3, C-3, D-3 and E-3). Theoretically, connectors and aluminum have different natural potentials in salt mist condition, an electric current will flow from the anode metal to the cathode, which will increases the corrosion on the anode. Therefore, supplying an external current on the connectors and aluminum frame would somehow influence the corrosion rate. From the data however, no significant change on corrosion rate was observed between the samples with and without current cycling. This is possibly due to the accelerated aging under salt mist condition was too severe for the connectors and the connectors failed too soon to show the effects of current cycling.

D. Installation Torque Requirements

The manufacturers should specify, in the module installation manual, the grounding methods including torque requirements that must be used to establish grounding connections. For example, for the connectors use teeth washer as a part of the conducting path would ask the installers to tighten the mounting screw to a certain force level to ensure that the teeth fully embeds in the aluminum frame surface. In this research, connector D was picked for the comparison study. D-1 to D-3 connectors were torqued to the specified value with a torque wrench; while identical connectors D'-1 to D'-3 were assembled using a regular wrench and the force was way below the torque requirement. Figure 8 shows that group D' connectors failed 5 times sooner than group D. This indicates that sample assembly force has great effects on connector failure time.

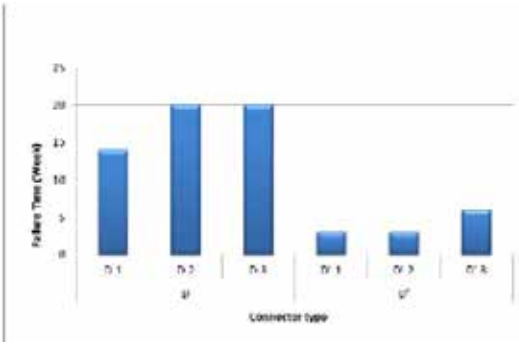


Figure 8 Failure time comparisons for connector D following torque requirements and not (D')

E. Failure Mechanism

The grounding connectors of all groups showed a considerable amount of surface corrosion after salt mist aging, and a build-up of white oxidation on the aluminum frames (Figure 9 and 10). The white oxidations were collected and tested under EDX. With oxygen and metal peaks detected, it is proved that the white powders were metal oxides (Figure 11). The metal oxides are always non-conductive and act as an insulating layer, which block and destroy the grounding connections. On some of the lug connectors, the tin plating had flaked off the surface and the inner copper had exposed. This could enhance the galvanic corrosion to occur as the tin-removed copper lugs were hardly pressed against the aluminum frames which creates a galvanic corrosion environment. Other forms of corrosions such as crevice corrosion and pitting corrosion were also observed.

The connectors or lugs created gaps and crevices and the differential aeration between the crevice and the external surface gave the crevice an anodic character and the external surface a cathodic character that prompted the crevice corrosion. Pitting corrosion includes local breakdown of protective passive film and always involves presence of chloride ions [6].

Figure 9 Build-up of white oxidations on the aluminum frame (screw sample)

Figure 10 Build-up of white oxidations on the aluminum frame (lug sample)

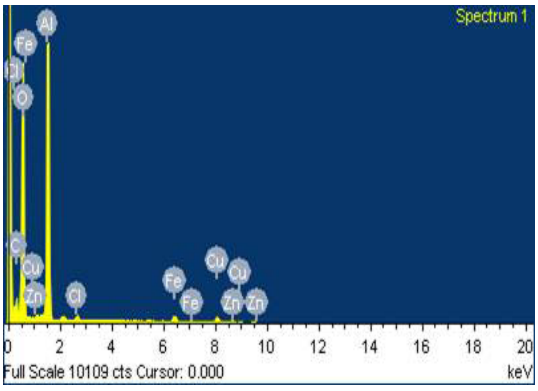


Figure 11 EDX measurements for the white oxidation on the aluminum frames

Summary and Conclusion

The reliability of different PV grounding connectors was compared by conducting accelerated aging under corrosive environmental conditions. The testing consisted of continuous damp heat and salt mist environmental exposure, in conjunction with periodical electrical current cycling. The connectors were evaluated by comparing the change in resistance of the test samples as the testing progressed. The results show that most of the samples were severely corroded and failed within weeks under the salt mist condition, while identical samples in the damp heat chamber were still in good condition. The presence of ions (Na + , Cl-, etc) in salt water had a much greater effect on the rate at which metals corrode than just in heat and high humidity. The uses of anti-oxidant coating and connector assembly force also have effects on grounding integrity. With regard to the failure mechanism, different forms of corrosion - including galvanic corrosion, pitting corrosion, and crevice corrosion - were observed during the aging tests. Evidence showed that the insulating metal oxide formed during the corrosion broke the electrical connections and failed the grounding system.

ACKNOWLEDGMENT

This Research was performed at the Plastic Industry Development Center (PIDC) and supported by the UL's Advanced Energy Safety R&D Center Project (AESC), Multinational Innovative R&D Centers In Taiwan Program, Taiwan Ministry of Economic Affairs (MOEA) and Solar ABCs.

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ACRONYMS

A	ampere
AC	alternating current
AHJ	authority having jurisdiction
ANSI	American National Standards Institute
ASTM	Formerly American Society for Testing and Materials, now ASTM International
AWEA	American Wind Energy Association
AWG	American wire gauge
Cr	chromium
CRD	certification requirements decision
DC	direct current
EGC	equipment grounding conductor
GFDI	ground fault detector interrupter
Hz	hertz
IEC	International Electrotechnical Commission
IECEE	IEC System of Conformity Assessment Schemes for Electrotechnical Equipment and Components
IEEE	Institute of Electrical and Electronics Engineers
kcmil	1,000 circular mils
mA	milliampere
NEC	National Electrical Code
NFPA	National Fire Protection Association
NRTL	Nationally Recognized Testing Laboratory
OCPD	overcurrent protection device
PV	photovoltaic
SS	stainless steel
STC	standard test conditions
STP	Standards Technical Panel
UL	Underwriters Laboratories

Solar America Board for Codes and Standards

www.solarabcs.org

Photovoltaic Module Grounding: Addendum Report on corrosion testing

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May 2013

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EXECUTIVE SUMMARY

This report is an addendum to a two-part study addressing the electrical grounding of photovoltaic (PV) modules. The Solar America Board for Codes and Standards (Solar ABCs), with support from the U.S. Department of Energy, commissioned the study to provide the PV industry with practical guidelines for module grounding and recommendations for improving product standards that certify modules and related grounding components. Solar ABCs published an interim "Lay of the Land" report on the topic in the spring of 2011, which described the many issues facing industry stakeholders. A final report documenting guidelines, safety considerations, and recommended changes to existing codes and standards, was published in April 2012. This addendum provides updated information and recommendations related to corrosion testing of module grounding components and connections.

The 2012 report addresses issues related to corrosion testing of PV module ground connections, but noted the need for subsequent updates given the level of activity occurring at the time of publication. That report presented details of a 2011 Underwriters Laboratories (UL) paper (Wang, Yen, Wang, Ji, & Zgonena, 2011) summarizing exploratory testing of different types of PV module grounding (bonding) devices in environmental chambers using both continuous damp heat and salt mist environmental exposure. The effects of current cycling, assembly force, and antioxidation coating application on grounding reliability were evaluated in conjunction with aging tests.

The study was noteworthy for the dramatic failure of components occurring during salt-mist exposure tests. Although it provided a great deal of valuable information, the study also raised questions about the appropriateness of the extreme conditions defined by the existing corrosion test standards in determining the performance of components in actual PV array field conditions.

In this addendum, we recommend adoption of newly published salt-mist test procedures in International Electrotechnical Commission (IEC) Standard 61701 (IEC, 2011): "Salt mist corrosion testing of photovoltaic (PV) modules." This standard specifically addresses testing issues particular to PV module frames and adopts cycling methods that better approximate the conditions experienced by PV components in a marine environment. We also recommend the adoption of procedures published in IEC 62716 (IEC, 2012), "Ammonia corrosion testing of photovoltaic (PV) modules." These tests are intended to address modules operating in highly corrosive wet atmospheres near agricultural or other industrial facilities.

Finally, we identify information and lessons learned from ongoing UL 2703 (UL, 2011) certification testing of module grounding components. This provides insight into the materials that are proving effective in corrosion testing as well as those that are not. This information has helped to identify less ambiguous criteria for determining the compatibility of various dissimilar metals.

AUTHOR BIOGRAPHIES

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Greg Ball is a Principal Engineer at DNV KEMA Renewables (formerly BEW Engineering) and has more than 20 years of experience in renewable energy technologies and their integration with the utility grid. Prior to joining BEW in 2009, he worked for nine years as manager and senior electrical engineer at PowerLight (later SunPower) Corporation, and was responsible for the electrical design of more than 100 MW of large-scale photovoltaic (PV) system installations in the United States and abroad. He serves as co-convenor on an International Electrotechnical Commission PV system working group, is a member of two Standards Technical Panels, and is a contributor to the National Electrical Code PV code-making panel.

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Solar America Board for Codes and Standards

The Solar America Board for Codes and Standards (Solar ABCs) provides an effective venue for all solar stakeholders. A collaboration of experts formally gathers and prioritizes input from groups such as policy makers, manufacturers, installers, and large- and small-scale consumers to make balanced recommendations to codes and standards organizations for existing and new solar technologies. The U.S. Department of Energy funds Solar ABCs as part of its commitment to facilitate widespread adoption of safe, reliable, and cost-effective solar technologies.

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Acknowledgment

This material is based upon work supported by the U.S. Department of Energy under Award Number DE-FC36-07GO17034.

TABLE OF CONTENTS

DISCLAIMER 2

EXECUTIVE SUMMARY 3

AUTHOR BIOGRAPHIES 4

SOLAR ABCS 5

ACKNOWLEDGMENT 5

INTRODUCTION 7

MODULE GROUNDING AND CORROSION 9

CORROSION DEFINED 11

CORROSION AND CURRENT STANDARDS 12

RECOMMENDED APPROACH FOR IMPROVING PERFORMANCE AND CERTIFICATION 15

CONCLUSIONS AND NEXT STEPS 18

ACRONYMS 19

REFERENCES 20

RESOURCES 20

Introduction

This report is an addendum to a two-part study of photovoltaic (PV) module grounding issues. Solar ABCs published interim and final reports from the study in 2011 and 2012, which discussed a wide range of module grounding issues; provided guidelines for designers, installers, and inspectors; and made recommendations for the evolving standards. This addendum focuses on corrosion issues and test recommendations based on developments that were ongoing at the time the previous reports were written. The subject is by no means closed and the industry has work to do to resolve issues of component reliability and certification. However, newly published International Electrotechnical Commission (IEC) standards provide a good model for improving certification tests, and generalized findings from recent Underwriters Laboratories (UL) certification tests offer valuable direction and guidelines for product manufacturers and designers.

PV modules are typically installed on aluminum or galvanized, painted, or stainless steel frame structures. These structures and any other electrically conductive components that could become energized by the PV array (or other electricity sources) and that could be accessible during routine servicing must be grounded to ensure safe touch voltages. The study addressed problems the industry faced with respect to limited grounding methods and equipment certification paths for components, and sought to address the issues with the following steps:

1. Publication of an interim Lay of the Land report, a survey of the existing situation in which stakeholders (system designers, module and component manufacturers, Nationally Recognized Testing Laboratories [NRTLs], and researchers) shared their experiences and recommendations to address the issues listed above. This interim report was published in the spring of 2011.
2. Evaluation of existing and new test procedures. This was primarily a UL-led effort to investigate expanded or enhanced current and accelerated aging test methods that can provide greater confidence in the long-term reliability of grounding methods.
3. Development of a final report making final recommendations for new or expanded tests to incorporate into standards, and documenting guidelines and procedures for public use. This report was published in April 2012.

Throughout this study's documents, the terms "ground," "grounding," and "grounded" are used to describe the connections to module frames that are the primary focus of the study. Note that there is a distinction between "grounded" and "bonded." Article 100 of the 2011 *National Electrical Code* (NFPA, 2011) defines these terms as follows:

- Grounded: Connected to ground or to a conducting body that extends the ground connection.
- Bonded: Connected to establish electrical continuity and conductivity.

The scope of the study focuses on the bonding of frames to other parts or conductors that are then grounded. This report uses the more general "grounding" term to describe both bonding and grounding unless bonding is specifically called out.

The applicable standards for evaluation and certification of module frame grounding are:

UL 1703: Flat-Plate Photovoltaic Modules and Panels
UL 1703 (UL, 2008) is the "primary" standard affecting module grounding and devices. Methods certified to UL 1703 and documented in module manufacturers' installation instructions are almost universally accepted by inspectors and authorities having jurisdiction. UL 1703 covers a range of safety and construction related requirements for modules, with a few sections dedicated to frame bonding, grounding, and continuity. It also establishes requirements for the means of grounding as well as continuity requirements subject to applied current and environmental (accelerated life) testing.

UL 2703: Rack Mounting Systems and Clamping Devices for Flat-Plate Photovoltaic Modules and Panels
UL 2703 (UL, 2011) is a new draft standard, meaning it is not yet an American National Standards Institute (ANSI) standard. It was created to address PV module mounting systems. It covers mechanical and other general issues for mounting systems, including grounding. The grounding section incorporates much of the same language used in UL 1703, applied broadly to the mounting system components. UL 2703 enables manufacturers to list individual grounding components independent of the racking certification. There is also a mechanism for establishing subsystem level testing of bonding—tests using multiple modules and components connected together, rather than single connections, for example—and impedance requirements for metal apparatus containing multiple strings of modules. The development of UL 2703 is a significant benefit to the PV industry as it provides a direct means for evaluating the use of structural hardware for grounding purposes.

MODULE GROUNDING AND CORROSION

One of the common failure modes of module grounding identified in the Lay of the Land report is corrosion of the bonds and connections. Failures from corrosion can have many causes. Galvanic corrosion resulting from the joining of dissimilar metals is probably the most common general cause. However, corrosion can also occur as a result of long-term exposure of components to cycling leakage current, which produces an electrolysis process. Failures due to corrosion can be attributed to the following general causes:

- Improper selection of materials for the bonded connection. Copper and aluminum bonds are the most common and have dramatic results, but other less obvious combinations may break down over time.
- Dissimilar metals in close proximity, which—depending on the electrolyte involved—causes corrosion when exposed to water, soil, or other conductive debris elements.
- Insufficient barriers between dissimilar metals, such as undersized or improperly installed stainless steel washers separating copper and aluminum.
- Good but inadequately protected connections after long-term exposure to leakage current, water, salt-humidity, and/or other corrosive agents. An example is a tin-coated assembly joining a copper wire and aluminum frame where the coating is inadequate to serve as a sacrificial barrier over the long term.

The following photos illustrate the destructive nature of the corrosive degradation in module grounding connections. The final photograph shows a newly installed bonding connection that appears fine at the outset but is destined to degrade due to the direct joining of copper and aluminum.

Figure 1: Corrosion between copper ground braid, stainless steel screw, and aluminum frame.

Figure 2: Corrosive degradation in a harsh environment.

Figure 3: Lost connection from corrosive bond.

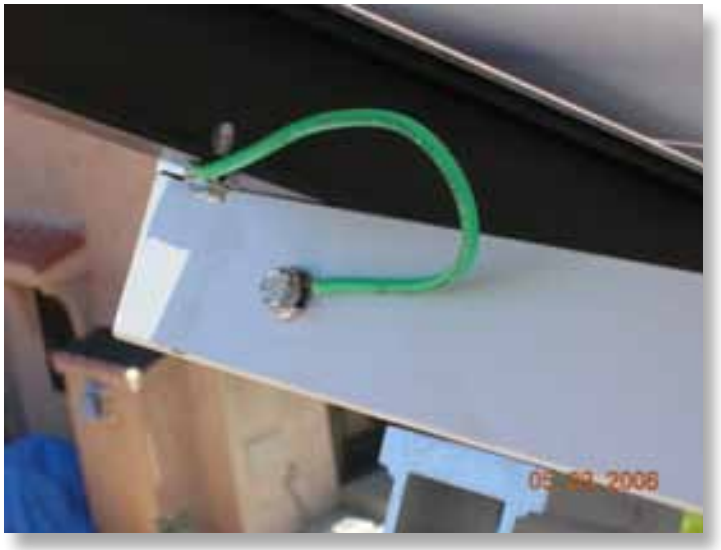

Figure 4: Connection of dissimilar (incompatible) materials, before corrosion begins.
Photo credit (Figures 1-4): John Wiles, Southwest Technology Development Institute, New Mexico State University

CORROSION DEFINED

Corrosion is the chemical reaction process that takes place in metals (or other materials), usually as a result of electrochemical oxidation, resulting in the gradual destruction of the metals. Galvanic corrosion, the type of corrosion that occurs in electrical connections, is a specific electrochemical process that occurs when two metals of different electrochemical potentials are in contact in some form of electrolyte. This combination allows current to flow from one metal (the anode), to the other (the cathode), potentially causing a destructive degradation of the anode material. The electrolyte for electrical connections of this type may be a liquid solution as in the case of batteries, but in the context of PV modules it is the environment of the installation, such as damp, humid air, possibly with salt content (such as near an ocean), dirt, or rain containing acids and alkalis.

The rate and aggressiveness of corrosion depends on many factors, but the primary issues are the electrical conductivity of the electrolyte, the difference of electrode potential between the metals, and the characteristics of the connection, such as the ratio between the cathode area and anode area. Corrosion is also more severe with direct currents than with alternating currents. Corrosion of the anode can actually reduce or prevent the corrosion process of the cathode. This is the basis for the use of sacrificial anode layers, which are material coatings or layers that allow a small area of metal to intentionally corrode and effectively halt additional corrosion of the more important materials while still maintaining the conductive function of the connection.

In electrical bonding connections such as module bonding or grounding, the primary cause of corrosion is the connection of dissimilar metals with incompatible electrochemical potential, and/or the aggressiveness of the environmental electrolyte, as discussed in the previous section.

CORROSION AND CURRENT STANDARDS

Both of the previous reports in this study discussed the numerous paths that have led to unnecessarily corroded grounding bonds. At a high level, the three contributing factors have been:

1. installation errors, which encompass incorrect use or installation of parts, improperly written instructions from manufacturers, or carelessness;
2. parts and components that have not been adequately tested to demonstrate resistance to corrosion; and
3. lack of adequate or appropriate test requirements in the module or component certification standards.

The rest of this report focuses on the 2nd and 3rd points as well as recommendations to improve the test requirements. UL 1703 (UL, 2008) (and by extension UL 2703 [UL, 2011]) currently addresses corrosion testing by giving guidance on the type of materials that can be bonded together, and by specifying tests on ground connection samples, after which the continuity tests must be repeated.

The matrix of acceptable and unacceptable metal combinations that can be used in the grounding means is shown in the figure below (published in UL's 2007 certification requirements decision for UL 1703 [UL, 2008] and included in UL 2703 [UL, 2011]). Acceptable combinations result in combined electrochemical potentials of less than 0.6V, and are shown below the stepped cutoff line in Figure 5.

Magnesium, magnesium alloys	Zinc, zinc alloys	80 tin/20 Zn on steel, Zn on iron or steel	Aluminium	Cd on steel	Al/Mg alloy	Mild steel	Duralumin	Lead	Cr on steel, soft solder	Cr on Ni on steel, tin on steel, 12 % Cr stainless steel	High Cr stainless steel	Copper, copper alloys	Silver solder, Austenitic stainless steel	Ni on steel	Silver	Rh or Ag on Cu, silver/gold alloy	Carbon	Gold, platinum	
0	0.05	0.55	0.7	0.8	0.85	0.9	1.0	1.05	1.1	1.15	1.25	1.35	1.4	1.45	1.6	1.65	1.7	1.75	Magnesium, magnesium alloys
	0	0.05	0.2	0.3	0.35	0.4	0.5	0.55	0.6	0.65	0.75	0.85	0.9	0.95	1.1	1.15	1.2	1.25	Zinc, zinc alloys
		0	0.15	0.25	0.3	0.35	0.45	0.5	0.55	0.6	0.7	0.8	0.85	0.9	1.05	1.1	1.15	1.2	80 tin/20 Zn on steel, Zn on iron or steel
			0	0.1	0.15	0.2	0.3	0.35	0.4	0.45	0.55	0.65	0.7	0.75	0.9	0.95	1.0	1.05	Aluminium
				0	0.05	0.1	0.2	0.25	0.3	0.35	0.45	0.55	0.6	0.65	0.8	0.85	0.9	0.95	Cd on steel
					0	0.05	0.15	0.2	0.25	0.3	0.4	0.5	0.55	0.6	0.75	0.8	0.85	0.9	Al/Mg alloy
						0	0.1	0.15	0.2	0.25	0.35	0.45	0.5	0.55	0.7	0.75	0.8	0.85	Mild steel
							0	0.05	0.1	0.15	0.25	0.35	0.4	0.45	0.6	0.65	0.7	0.75	Duralumin
								0	0.05	0.1	0.2	0.3	0.35	0.4	0.55	0.6	0.65	0.7	Lead
									0	0.05	0.15	0.25	0.3	0.35	0.5	0.55	0.6	0.65	Cr on steel, soft solder
										0	0.1	0.2	0.25	0.3	0.45	0.5	0.55	0.6	Cr on Ni on steel, tin on steel, 12 % Cr stainless steel
											0	0.1	0.15	0.2	0.35	0.4	0.45	0.5	High Cr stainless steel
												0	0.05	0.1	0.25	0.3	0.35	0.4	Copper, copper alloys
													0	0.05	0.2	0.25	0.3	0.35	Silver solder, Austenitic stainless steel
														0	0.15	0.2	0.25	0.3	Ni on steel
															0	0.05	0.1	0.15	Silver
																0	0.05	0.1	Rh or Ag on Cu, silver/gold alloy
																	0	0.05	Carbon
																		0	Gold, platinum

Ag Silver
Al Aluminium
Cr Chromium
Cd Cadmium
Cu Copper
Mg Magnesium
Ni Nickel
Rh Rhodium
Zn Zinc

NOTE – Corrosion due to electrochemical action between dissimilar metals which are in contact is minimized if the combined electrochemical potential is below about 0.6 V. In the table the combined electrochemical potentials are listed for a number of pairs of metals in common use; combinations above the dividing line should be avoided.

Figure 5: Electrochemical matrix of common metal combinations.

The environmental or accelerated aging tests defined in UL 1703 (UL, 2008) include:

- Section 35—Temperature Cycling Test, 200 cycles of various temperature changes from as low as minus 40 to plus 90 Celsius;
- Section 36—Humidity Test, 10 cycles of humidity-freezing; and
- Section 37—Corrosive Atmosphere testing, including salt spray test and moist carbon dioxide/sulfur dioxide test.

Some particularly poor bi-metallic connections may demonstrate problems after undergoing the humidity tests of Section 36, but most do not. The tests in Section 37 are those that are likely to lead to significant degradation of the connection, but those tests historically are only required for modules with steel frames. Because most module frames are made of aluminum, the tests are effectively optional for the broad manufacturing base.

During the past decade, a wide range of module ground connection components and methods were developed and implemented, showing mixed results in the field. To get a sense of the corrosion susceptibility of these various methods, UL performed exploratory tests during the course of the Solar ABCs study and published a paper on those findings entitled "Accelerated Aging Tests on PV Ground Connections," (Wang et al., 2011). This paper was discussed at length and included in its entirety as an appendix to the final report published in 2012.

That discussion won't be repeated in full here, but some of the major points from the study and the subsequent industry feedback include:

- The study objective was to investigate the long-term effectiveness of different PV grounding devices by measuring the contact resistance at the junction between the bonding devices and aluminum frames before and after exposure to simulated harsh environmental conditions.
- The bonding types included the three most common approaches (and listed methods) used today—copper wire connections via screw/washer/nut assemblies, lay-in lug assemblies, and grounding clips.
- Identical sample sets were installed and aged separately using:
    - Damp heat aging according to IEC 61215 (IEC, 2005), "Crystalline silicon terrestrial photovoltaic (PV) modules—Design qualification and type approval." This consisted of 85°C ambient temperature and 85% relative humidity for 1,000 hours.
    - Salt-mist aging according to IEC 60068-2-11 (IEC, 1981), "Basic Environmental Testing Procedures, Part 2: Tests-Test Ka: Salt Mist." This standard compares resistance to deterioration from salt mist between materials of similar construction, and is used to evaluate the quality and the uniformity of protective coatings. The environment consists of continuous fine mist of aerated 3% NaCl solution buffered to a pH of 5.5.
- In the damp-heat condition, the resistances for all bonding devices remained low (<0.05 ohm) and had almost no change over 20 weeks.
- In the salt mist condition, however, most samples showed visible signs of severe corrosion and failed the ground continuity test in weeks, where resistance failure was set at >10 ohms.

- Initial feedback included recommendations that there be additional review of the attachment methods by manufacturers of the grounding clips and lay-in lugs—small but meaningful differences in the use of washers, for example. One lay-in lug manufacturer's instructions recommend using a flat washer between any lock or star washer and the lug surface. This is presumably to prevent excessive penetration of the tin plating on the lug and exposure of the underlying copper to galvanic corrosion.
- Most stakeholders (manufacturers and other NRTLs) suggested that the tests were a welcome start, but also highly recommend additional tests with greater participation by industry to define the scope.

Although it is widely acknowledged that tests need to be more rigorous to help reduce corrosion issues, many in the industry have expressed concern about using a testing approach employing continuous exposure to salt mist. IEC 60068-2-11 (IEC, 1981) and ASTM International (ASTM) B117 (ASTM, 2011) have both been cited and used in component tests, and both prescribe continuous salt mist exposure. The general concern is that the corrosion mechanisms induced by the IEC or B117 tests are known to often differ from those found in the field, and therefore care must be taken to select the appropriate test methods. The ASTM standard itself cautions against the use of the method to predict corrosion performance in the field, particularly in sections 3.2, 3.2.1, and 3.2.2:

> *3. Significance and Use*
>
> *3.1 This practice provides a controlled corrosive environment, which produces relative corrosion resistance information for specimens of metals and coated metals exposed in a given test chamber.*
>
> *3.2 Prediction of performance in natural environments has seldom been correlated with salt spray results when used as standalone data.*
>
> *3.2.1 Correlation and extrapolation of corrosion performance based on exposure to the test environment provided by this practice are not always predictable.*
>
> *3.2.2 Correlation and extrapolation should be considered only in cases where appropriate corroborating long-term atmospheric exposures have been conducted.*

Section 3.1 is notable as well, however, for indicating that relative corrosion resistance information can be obtained from the test of specimens. Even if the UL exploratory testing raised more questions than it answered with respect to the components themselves, it did provide some useful (if not complex) information on relative improvements in performance. For example, samples using the antioxidant coating lasted longer than uncoated samples before failing, and connections that were significantly under-torqued failed much more quickly than those that used a torque wrench to achieve the manufacturer specifications. This result highlights the need to investigate more specific torque variability—to determine the failure rate difference if the connection is under-torqued a small but measurable amount, for example. Further study should also examine the impact on corrosion rate of connections that have come loose but have been re-torqued. It is important to note that over-torqueing a connection can also lead to premature failure.

RECOMMENDED APPROACH FOR IMPROVING PERFORMANCE AND CERTIFICATION

Based on the discussions so far, the recommendations from this study are:

1. Tests should be modified to better reflect the actual environmental processes seen by PV modules in the field. This is not to imply the tests can replicate the field corrosion process, because accelerated testing can never be an accurate substitute for the long-term degradation mechanisms.
2. Test results should be used to identify relative performance superiority or inferiority in the use of methods and materials, and not necessarily be considered a predictor of failure time or failure mode.
3. Manufacturers should stay informed about the bonding material pairings that are or are not demonstrating success in UL 1703 (UL, 2008) and 2703 (UL, 2011) certification tests. Although the electrochemical potential table in Figure 5 shows a very wide range of possible component combinations, it is lacking in some areas and not highly specific in others, and actual test results with alloy variations are equally informative.

Improved Test Procedures

A key recommendation is to propose UL 1703 Standards Technical Panel adoption of procedures from new IEC standards that specify salt fog and ammonia tests for PV modules.

The second edition of IEC 61701: "Salt mist corrosion testing of photovoltaic (PV) modules" was published in 2011 (IEC, 2011). The revision has significant differences from the first edition and is a substantive departure from the approach used in ASTM B117 (ASTM, 2011) and IEC 60068-2-11 (IEC, 1981). For one, its test basis is derived more from IEC 60068-2-52 (IEC, 1996), which is widely used in the electronic component field and thought to be better suited to PV module assemblies. The tests also better reflect field conditions. Most significantly, the modules are exposed to cycles of alternating salt fog followed by humidity storage under controlled temperature and relative humidity conditions. This sequence better reflects the module's corrosion processes in punishing marine environments than that of a continuous salt-fog test.

The standard also draws on IEC 60068-2-52 (IEC, 1996) by offering different levels of test severity, which are representative of different installation environments:

- One severity level is applicable to systems installed in a marine environment, with routine exposure to a wet atmosphere with dissolved salt.
- Four other severity levels are defined based on alternating exposure to salt- based and dry or humid atmospheres. One example is representative of normally dry environments where the use of salt is occasionally used to melt ice.

IEC 61701 (IEC, 2011) requires a series of performance related tests following the salt-fog exposure, among them a ground-continuity test according to IEC 61730-2 (IEC, 2004) (for crystalline silicon and thin film modules), and IEC 62108 (IEC, 2007) (for concentrating PV modules). For the purposes of the UL 1703 (UL, 2008) (and UL 2703 [UL, 2011]) standard revisions, we recommend no change to the continuity tests as currently written, only to the salt-fog test procedures in Section 36. Another recommendation is to have the test be applicable to all metal-framed modules (because current language only applies to steel frames, which—as mentioned earlier—are rarely used). Grounding hardware or assemblies can be tested and certified for a specific environment based on the severity level choice.

The IEC is also publishing IEC 62716, "Ammonia corrosion testing of photovoltaic (PV) modules," which follows closely the principles and approach taken in IEC 61701 (IEC, 2011). In IEC 62716, the tests are intended to address modules operating in highly corrosive wet atmospheres near agricultural or other industrial facilities involving concentrations of dissolved ammonia. Samples are subjected to cycles of exposure—eight hours of ammonia exposure in higher temperatures followed by 16 hours with no ammonia and lower temperatures. IEC 62716 is in final draft review by the technical committee. and will likely be published in 2013. It is recommended that this test or a similar one also be considered as an addition to the existing tests in UL 1703 (UL, 2008) and UL 2703 (UL, 2011). At this time there is no recommendation to change or remove the existing moist carbon dioxide/sulfur dioxide corrosive atmosphere test UL 1703 (Section 37.2). As in the case of the salt-fog tests, it is recommended that manufacturers have the option of choosing tests and severity levels, but in any case the listing should clearly document which environments the components have been certified to operate in.

Lessons From Field and Recent Testing Experience

Grounding devices and mounting means that have historically performed well in the field include combinations of:

- copper or a copper alloy containing not less than 80% copper, which may be coated or plated to avoid galvanic corrosion;
- stainless steel containing a minimum of 16% chromium (Cr) or 5000 or 6000 series aluminum alloys; or
- carbon steel, which may be coated or plated to avoid corrosion.

Connections that have to date shown galvanic compatibility in almost all service environments contain any combination of the following (with caveats related to sufficient thickness of platings or coatings):

- 5xxx or 6xxx series aluminum alloys and commercially pure aluminum,
- stainless steel containing a minimum of 16% Cr,
- nickel,
- tin,
- zinc, and
- zinc-aluminum alloys.

In 2012, UL experienced a surge of activity for UL 2703 (UL, 2011) grounding and bonding component certifications, and the findings with respect to different types of steel supplement the material recommendations above. Although there are occasional exceptions, the following generalizations can be made with respect to the success of bonding resistance and short-circuit tests performed after environmental conditioning:

- Components with 300 Series stainless steel have been passing well (incorporating minimum 16% Cr—austenitic chromium-nickel alloys).
- Components with 200 Series stainless steel have had mixed results (austenitic chromium-nickel-manganese alloys).
- Components with 400 Series stainless steel generally are not passing (ferritic and martensitic chromium alloys).
- Components with ASTM A690 or better galvanized steel have been successful (Atmospheric Corrosion Resistance for Use in Marine Environments).
- Components with A660 galvanized steel (and classes below) are not faring as well.
- Zinc thickness has been demonstrated to be more relevant in test results than the galvanization method (electroplating or hot-dipped). Having said that, hot-dipped galvanized steel generally fares better.

In the previous Solar ABCs reports from this study, we made the general recommendation to simplify the list of materials used for grounding devices and mounting means, based on field and industry experience. This was considered a practical alternative to defining acceptable combinations using the table in Figure 5, which by itself lacks specificity with certain alloys and does not provide sufficient guidance for the determination of electrochemical potentials.. However, it is not our intent to impose restrictions on the use of alternate materials in the standards. The standards should identify functional requirements but not limit creativity or innovation with respect to materials and combinations. In order to realize this, however, new requirements and tests need to be developed and proposed to revise the standard. UL is currently in the process of creating a new expanded table and procedure for determining acceptable metal combinations. This will incorporate information gained from the ongoing UL 2703 component testing described earlier, but will also document a more detailed process for measuring the electrochemical potential so that a consistent approach can be used to test metals not included in the table. The important outcome is the long-term performance and integrity of the electrical connections once subjected to the accelerated aging and corrosion tests, and their subsequent performance in the field.

CONCLUSIONS AND NEXT STEPS

This report provides a brief update on findings related to module and ground component corrosion, and presents recommendations to adopt revised accelerated aging test procedures recently published by the IEC. UL 2703 (UL, 2011) certification testing at UL and other NRTLs is providing valuable information on the performance of various steels and alloys under accelerated aging conditions. We expect that there will also be plenty of new valuable information from manufacturers and test labs during the next few years that will help set the direction for improved component designs and testing. With this in mind, important next steps for the industry include:

- The Standard Technical Panels for UL 1703 (UL, 2008) and UL 2703 (UL, 2011) should review the IEC standard procedures outlined in this report. Possible outcomes are formal adoption of the IEC standards as U.S. ANSI standards or adoption of similar test procedures in the next revision of UL 1703 and UL 2703.
- Expanded exploratory testing building on the tests performed by UL in Taiwan is encouraged to address recommendations and feedback coming from the industry.
- A forum similar to Solar ABCs should continue to help consolidate and circulate information from the field and from various stakeholders working on corrosion analysis and mitigation.

ACRONYMS

ANSI	American National Standards Institute
ASTM	Formerly American Society for Testing and Materials, now ASTM International
Cr	chromium
IEC	International Electrotechnical Commission
IECEE	IEC System of Conformity Assessment Schemes for Electrotechnical Equipment and Components
IEEE	Institute of Electrical and Electronics Engineers
NEC	*National Electrical Code*
NFPA	National Fire Protection Association
NRTL	Nationally Recognized Testing Laboratory
PV	photovoltaic
UL	Underwriters Laboratories

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The Ground-Fault Protection Blind Spot: A Safety Concern for Larger Photovoltaic Systems in the United States

A Solar ABCs White Paper

January 2012

Prepared for:
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EXECUTIVE SUMMARY

This document addresses an important safety issue in the design of many U.S. photovoltaic (PV) systems. This safety issue—undetected faults in grounded PV array conductors—came to light during investigations into two well-publicized PV system fires. The first occurred on April 5, 2008, in Bakersfield, California, and the second occurred on April 16, 2011, in Mount Holly, North Carolina.

The investigations into these fires expose a "blind spot" in ground-fault protection in larger PV systems and provide an opportunity to explore the safety implications of inadequate ground-fault protection in a public forum. As investigators develop an understanding of the root causes of the Bakersfield and Mount Holly fires, they will also develop a better understanding of the complex nature of faults and fault currents in PV arrays, which will benefit all stakeholders.

This paper provides a basic explanation of the cause of these fires, followed by an outline of a limited research plan designed to develop solutions. It also includes preliminary fire mitigation strategies and equipment retrofit recommendations to reduce fire danger in new and retrofit applications based on results of the fire investigations to date.

The preliminary mitigation strategies and equipment retrofit recommendations listed in this white paper include:

- proper installation techniques with close attention to wire management,
- annual preventative maintenance to identify and resolve progressive system damage,
- introduction to the use of data acquisition to monitor the operation of all PV systems at a level sufficient to determine if unscheduled maintenance is required, and
- additional ground-fault and PV array isolation sensing devices that can be incorporated into the data system to alert operators to potential problems so that maintenance personnel can be dispatched well in advance of damage that could lead to a fire.

The Solar America Board for Codes and Standards (Solar ABCs) is leading a broad industry- and stakeholder-based working group to research this problem and develop effective mitigation strategies. Until the working group research is completed, it is not known which inverters and which GFDI schemes are most susceptible to the blind spot phenomenon, but larger inverters with the blind spot represent a potential fire hazard that must be addressed. Early results from large PV systems retrofitted with protective devices indicate that these devices may eliminate the blind spot without requiring redesign of the system.

The types of protective devices that have currently been retrofitted to existing inverters for evaluation include:

- differential current sensors (also known as residual current detectors or RCDs) installed on feeders entering the array combiners on each system, and
- insulation resistance monitors that measure the resistance to ground on a PV array while it is not operating.

In addition, other protective equipment may help mitigate fire danger in new systems, including:

- contactor combiners, which constitute an additional safety step beyond the differential current sensors and insulation monitors included in new inverters;
- arc fault detectors, which are required by the 2011 National Electrical Code; and
- module-level controls, which can shut the power off from each module.

Based on the limited investigations to date, it is recommended that PV systems with damaged conductors be identified and repaired as soon as practical. Once the Solar ABCs research project is complete, a final report will be published to inform all potentially affected PV system owners of all findings and recommendations necessary for them to make informed decisions about whether or not to implement retrofit or other proposed modifications.

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Bill Brooks has worked with utility-interconnected photovoltaic (PV) systems since the late 1980s. He is a consultant to the PV industry on a variety of performance, troubleshooting, and training topics. During the past 11 years, his training workshops have helped thousands of local inspectors, electricians, and installers understand and properly install PV systems.

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Solar America Board for Codes and Standards

The Solar America Board for Codes and Standards (Solar ABCs) is a collaborative effort among experts to formally gather and prioritize input from the broad spectrum of solar photovoltaic stakeholders including policy makers, manufacturers, installers, and consumers resulting in coordinated recommendations to codes and standards making bodies for existing and new solar technologies. The U.S. Department of Energy funds Solar ABCs as part of its commitment to facilitate widespread adoption of safe, reliable, and cost-effective solar technologies.

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Table of Contents

1 Introduction....1

2 The Problem—Ineffective Ground-Fault Protection....2

2.1 The Bakersfield and Mount Holly Fires....2

2.2 A Common Thread....2

2.3 The Sequence of Events Leading to the Fires....3

3 Codes and Standards Requirements....7

3.1 National Electrical Code....7

3.2 Ground-Fault Protection Device Test Standard....7

3.3 The Blind Spot....7

4 The Root Cause....9

5 Solar ABCs Ground-Fault Blind Spot Research Project....10

6 Possible Mitigation Strategies to Prevent Fires in Large PV Systems....11

6.1 Installation Inspections....11

6.2 Annual Preventative Maintenance....12

6.3 PV System Monitoring....12

6.4 Possible Retrofits for Existing PV Systems....14

6.5 Equipment to Consider for New PV Systems....15

6.6 Implementation of Mitigation Strategies....16

1. Introduction

This document addresses an important safety issue in the design of many U.S. photovoltaic (PV) systems. This safety issue—undetected faults in grounded PV array conductors—came to light during investigations into two well-publicized PV system fires. The first occurred on April 5, 2008, in Bakersfield, California, and the second occurred on April 16, 2011, in Mount Holly, North Carolina.

There have been other similar fires, but they are not public knowledge and investigation results are not available for open discussion. The fires at Bakersfield and Mount Holly, therefore, provide an opportunity to explore the safety implications of suspected inadequate ground-fault protection in a public forum.

Solar America Board for Codes and Standards (Solar ABCs) has initiated a short-term research project with broad participation from PV industry, owners, and the enforcement community to better understand the blind spot problem and develop recommendations to address any safety concerns. Ultimately, however, the individual PV system owner will have to evaluate the risk and decide which recommended corrective actions to implement.

The intent of this white paper is not to blame PV component and system installers, designers, or manufacturers. As investigators develop an understanding of the root causes of these fires, they also develop a better understanding of the complex nature of faults and fault currents in PV arrays, a valuable benefit to all stakeholders.

This paper provides a basic explanation of the current understanding of the cause of these fires, followed by an outline of a limited research plan designed to propose solutions. Based on results of this research, Solar ABCs will recommend strategies for mitigating future fires in existing and new installations. Effective ground-fault detection is a high priority for ensuring the safety of PV systems in the United States.

2. The Problem—Ineffective Ground-Fault Protection

2.1 The Bakersfield and Mount Holly Fires

Pete Jackson, an electrical specialist with the city of Bakersfield, documented the Bakersfield fire (Jackson, 2009) shortly after the event. The Jackson report provides basic insight into the cause of the fire, but lacks emphasis on key factors that contributed to the fire. The author of this white paper wrote a follow-on article for SolarPro magazine (Brooks, 2011) that expands on Jackson's report and emphasizes the larger safety concerns that the Bakersfield Fire exposed. Based on an understanding of the source of the Bakersfield fire, the article predicted that similar fires would occur in the future.

The April 16, 2011, fire in Mount Holly, North Carolina, was such a recurrence. This fire was documented in a report for Duke Energy by this author, which has seen limited but open distribution within the utility community. Many of the key details of that report are presented in this white paper.

2.2 A Common Thread

Both reference fires show evidence of significant arcing at one location in the PV array, although the fire ignited in a completely different section of the array. That is, in both fires there was significant damage in a seemingly unrelated portion of the array away from the initial sources of ignition. Jackson connects the coincidence of these faults in his report, but he questions the likelihood of a repeat event. The *SolarPro* article showed that the problem was ultimately in the blind spot of ground-fault protection equipment and therefore an apparent general concern to the PV industry in the United States.

As in the Bakersfield Fire, the Mount Holly fire caused significant damage in two different locations at the same time. At Mount Holly, the faults existed inside two different combiner boxes at the same time. The likelihood of these two faults initiating simultaneously in different locations is extremely small. Thus, it is likely that one fault existed for some period of time prior to the initiation of the second one. This is the fundamental insight that led to an understanding of the root cause of the fires.

In summary, it appears that at some time before the ignition of the fires, one fault occurred that was allowed to continue undetected, apparently due to an ineffective ground-fault detection scheme.

The National Electrical Code (NEC) and Underwriters Laboratories (UL) 1741 require that a ground-fault detector and interrupter (GFDI) be part of every PV system. Traditional safety requirements are based upon a single fault scenario. However, a problem may arise with a ground fault occurring in the grounded PV array conductor (the array positive or negative conductor that is bonded to earth ground, typically in the inverter). If this fault does not trip the GFDI, a current path may be created which inhibits an inverter from interrupting future ground faults when they occur. Within this white paper, ground faults on the grounded conductor of insufficient magnitude to be detected by existing ground-fault equipment are said to fall within a detection "blind spot." The blind spot is a potential condition that can occur in any conductor of the grounded pole of an array.

Recent system reviews by the Solar ABCs team and others have found that faults on grounded conductors in a PV array can be extremely difficult to detect with methods typically used in currently available ground-fault protection equipment. This is because the conductor is already grounded, so additional grounds on the conductor have little voltage differential to drive the current necessary to blow the protective ground-fault fuse. In this undetected condition, ground faults on the grounded conductor may exist indefinitely in a PV array, establishing a new "normal" condition that renders the ground-fault protection device unable to interrupt a second ground-fault current. In this condition, the clearing of the ground-fault fuse caused by an ungrounded conductor fault may drive the fire event by applying 500 volts to the first initially grounded conductor fault location.

2.3 The Sequence of Events Leading to the Fires

Based on the author's investigation, a similar sequence of events preceded the fires in Bakersfield and Mount Holly. In both cases, the evidence suggests that an undetected fault existed in the grounded conductor of the array. The line diagram in Figure 1 shows a ground-faulted string conductor similar to the likely first fault in the Bakersfield fire. The line diagram in Figure 2 shows a ground-faulted subarray conductor similar to the likely first fault in the Mount Holly fire. How long these assumed faults existed is unknown.

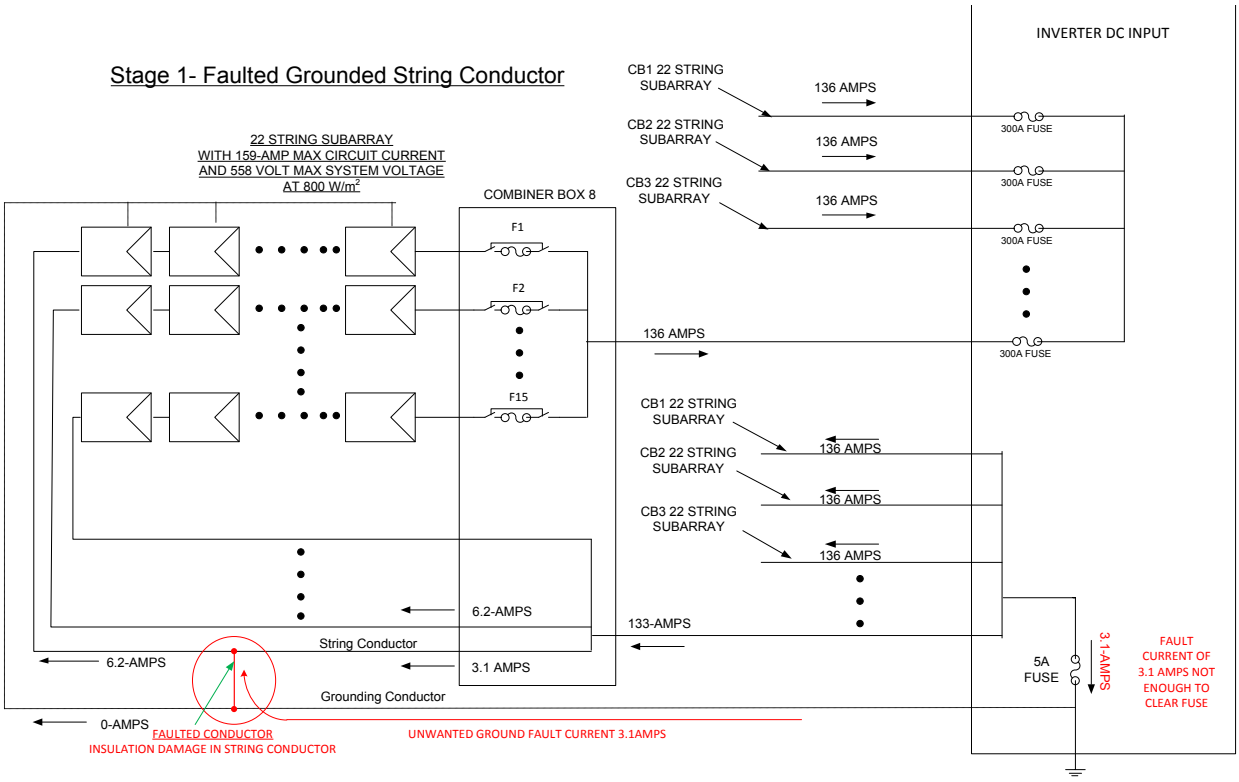

Figure 1: Ground-Faulted String Conductor, the Assumed First Fault—Bakersfield Fire

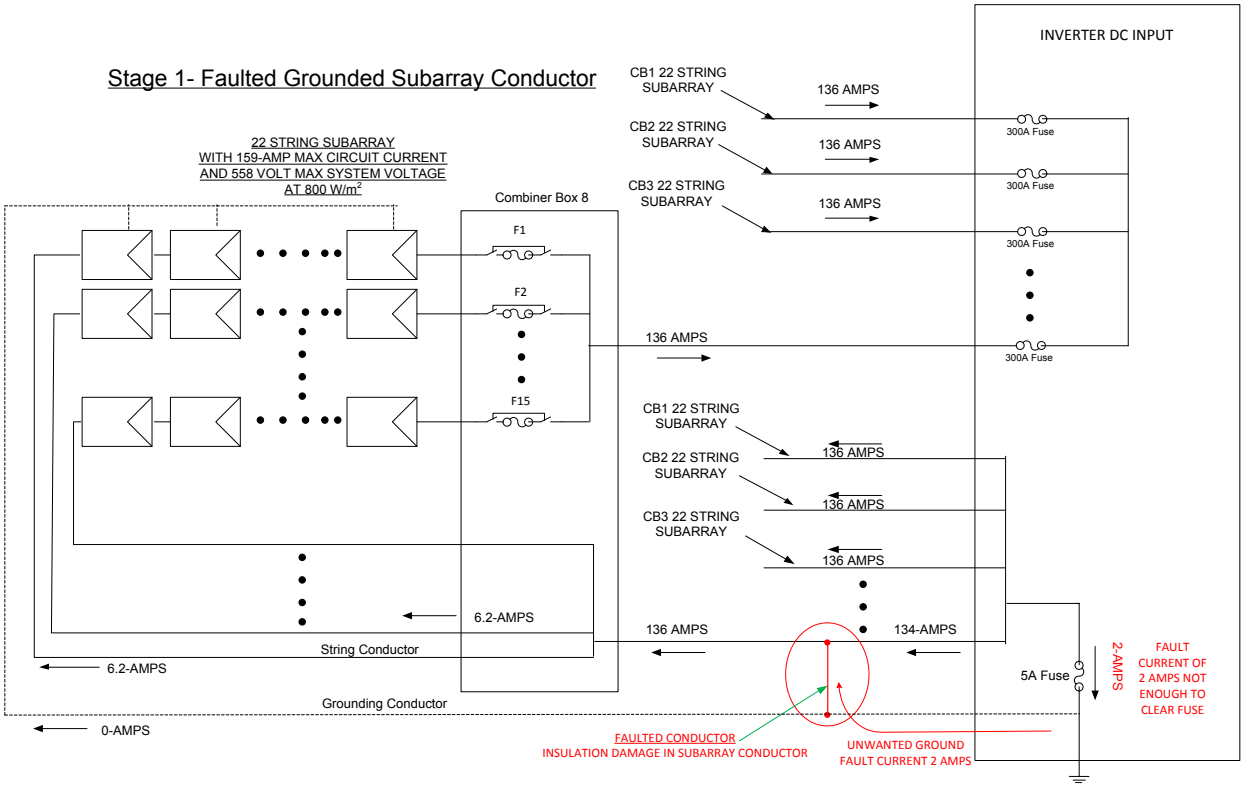

Figure 2: Ground-Faulted Subarray Conductor, the Assumed First Fault—Mount Holly Fire

The evidence suggests that sometime after the initiation of an undetected fault in the grounded conductor, a second fault occurred in the ungrounded conductor. Ordinarily, when a fault is detected on the ungrounded conductor, the ground-fault detection circuit opens the ground-fault fuse, thus opening the faulted circuit and interrupting all current flow.

As the figures illustrate, when there is an existing fault in the grounded conductor, blowing the ground-fault fuse can no longer interrupt all fault current. Because a return path has already been established in the faulted grounded conductor, the array becomes short circuited between the faulted grounded conductor and the second ungrounded conductor fault. The ground-fault protector in the inverter is not in this circuit and is unable to stop the flow of current.

Figure 3 shows the second fault in a fire similar to the Bakersfield event. In this scenario, the short circuit current is forced through the small 10 American wire gauge (AWG) grounded string conductor, causing a conductor insulation fire. Figure 4 shows the second fault in a fire similar to the Mount Holly event, in which the array short circuit current is forced through the poor inadvertent grounding connection, causing an arcing fire.

A 500-kilowatt (kW) PV array can have more than 1,300 amps of available short circuit current, which can cause enormous damage during this short circuit condition. If the two connection points were intentionally made with terminations able to handle the current, there would be little if any hazard. Unfortunately, these connections are made with only incidental contact that can evolve dramatically into intense arcs with operating temperatures of more than 2,000°C. These arcs can jump gaps between metal parts up to six inches apart.

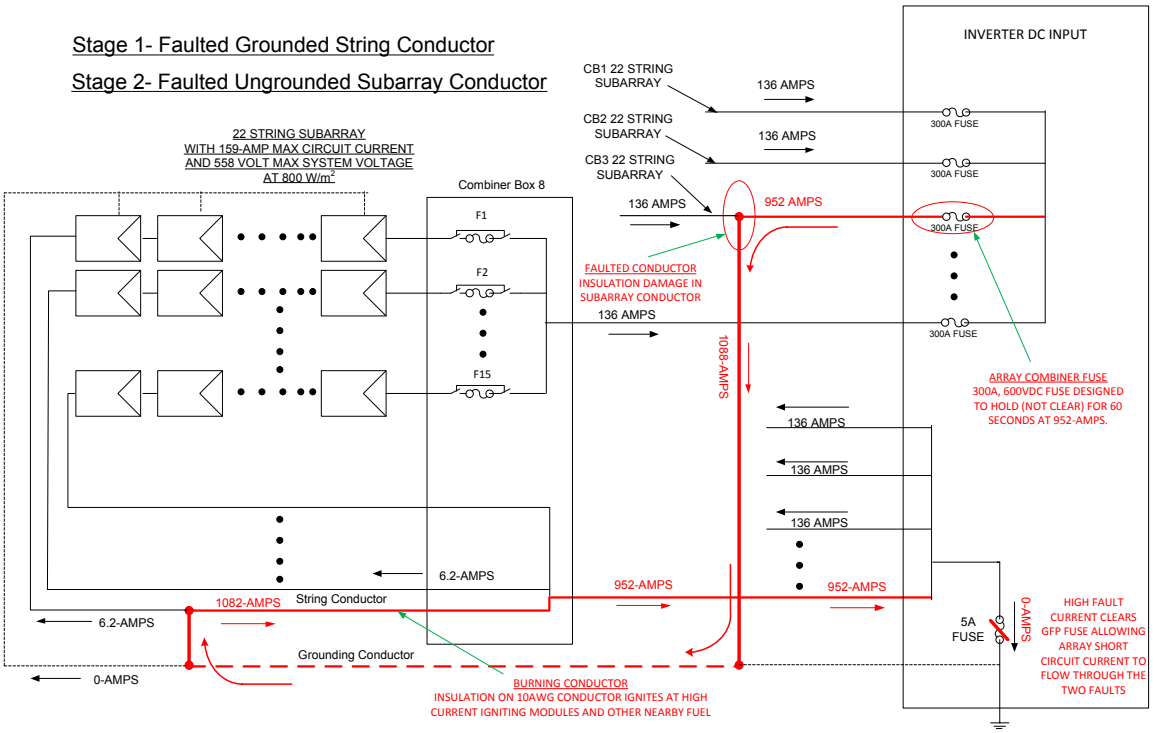

Figure 3: Second Ground-Faulted Conductor, Representative of the Bakersfield Fire

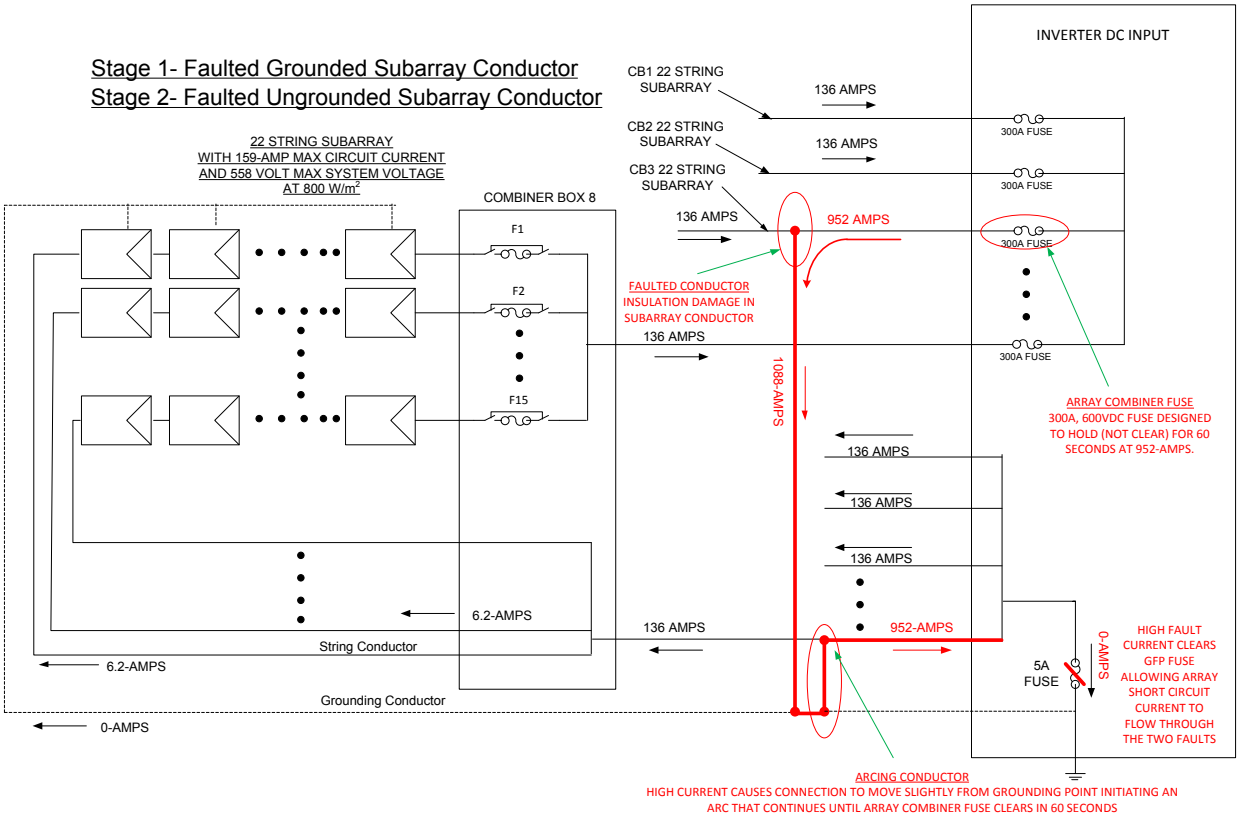

Figure 4: Second Ground-Faulted Conductor, Representative of the Mount Holly Fire

3. Codes and Standards Requirements

3.1 National Electrical Code

The NEC, in article 690.5 (A), requires the following:

> (A) Ground-Fault Detection and Interruption. The ground-fault protection device or system shall be capable of detecting a ground-fault current, interrupting the flow of fault current, and providing an indication of the fault.

The requirement in the NEC and UL 1741 standard that covers PV inverters addresses only ground-fault current in grounded PV systems. The NEC requirements do not address fault locations or fault current trip limits. Experience in the United States has found that although fault current is undesirable, all U.S. PV arrays have small current flows to ground, generally referred to as leakage current. These current flows increase in larger PV arrays and with certain PV module technologies and designs.

3.2 Ground-Fault Protection Device Test Standard

The present version of UL 1741 requires inverters to detect ground faults based on the magnitude of the fault current measured by the GFDI device. The trip limits set in the standard are based on the size of the system, and are derived by extrapolating the maximum allowable leakage current from a single PV module to the leakage from a large array field. The trip current limits are set conservatively to prevent nuisance tripping, particularly for modules that only marginally meet the leakage requirements. The allowable trip limits in UL 1741 range from 1 amp for inverters rated up to 25 kW to 5 amps for inverters greater than 250 kW.

3.3 The Blind Spot

If a ground fault occurs with current less than the trip threshold established by the UL 1741 standard, it cannot be detected or "seen" by the GFDI device. Hence, in this context, the device is said to have a blind spot (more formally known as a "lower limit of detection"). It is axiomatic that bigger PV systems, which have higher trip thresholds than smaller systems, must also have a larger blind spot than smaller systems.

This may explain why our first observations of this problem occurred in larger PV systems. With research, we may find that scenarios that lead to fires can also develop in smaller PV systems with smaller detection thresholds, possibly coupled with reduced short circuit current designs. A key area of focus for future Solar ABCs research will be understanding minimum system sizes that have a blind spot and identifying the appropriate fault current detection settings that enable the system to operate safely.

4. The Root Cause

A large fire often consumes the evidence of its origins. However, what evidence remained from the two fires under discussion here suggests similar root causes.

The evidence suggests that the ignition of the Bakersfield fire resulted from two faults occurring in two significantly different wire sizes in the PV array. The first fault was in a small grounded conductor. Failure to detect this first fault created the potential for the faulted grounded conductor to become part of a circuit for which it was not designed.

Physical evidence from the Bakersfield fire suggests that about 1,000 amps flowed through the faulted grounded conductor, a small unprotected 10 AWG wire. The wire insulation burned and ignited other fuel in the immediate vicinity. Because NEC installation requirements do not allow overcurrent protection devices in the grounded conductors of grounded PV arrays [NEC Article 690.13], full array current flowed unimpeded through the ground fault in the string-level wiring of the Bakersfield system.

The same scenario is suggested in the Mount Holly fire, but here the evidence indicates that both faults occurred in large combiner box feeder conductors. This was unexpected, because conventional wisdom assumes that a fault in a grounded large conductor would blow the ground-fault fuse and shut down the inverter. However, full

review of the Mount Holly fire suggests that even large grounded feeder conductors can be faulted and remain in the blind spot of the ground-fault protection device. Two months before the Mount Holly fire, maintenance inspection personnel photographed conductor insulation damage in two sections of the array that were later severely damaged in the fire. Although the inspectors were concerned that this damage would cause the ground-fault protection system in the inverter to shut the system down, they did not fully understand the threat of fire because so few fires have been reported.

5. Solar ABCs Ground-Fault Blind Spot Research Project

Solar ABCs has initiated a short-term research project to better understand the blind spot problem and develop recommendations to guide the PV industry as it addresses any safety concerns. Ultimately, the PV system owner must evaluate the risk and implement corrective actions. This evaluation requires a solid basis of data in order to make informed decisions.

The Solar ABCs research project has the following objectives:

- Determine the conditions uner which existing ground-fault protection is inadequate. For example, confirm the identification of "systems at risk" with field tests by metering systems with no faults, introducing a fault, and observing whether the inverter detects the fault. Factors to examine include:
    - array size, age, topology, and possibly climate (what is the minimum system size that will develop the blind spot problem, for example.);
    - different PV technologies, including crystalline and thin-film and their respective leakage characteristics; and
    - protection schemes used by inverters that are either effective or ineffective at detecting the introduced fault.
- Develop a mitigation proposal that can be implemented through changes to the *NEC* and UL standards.
    - The mitigation proposal currently under consideration is a combination of a morning check and detection of fault current by measuring differential current. The research project will determine values for insulation resistance and differential current.

The Solar ABCs will publish a final report detailing the research results and possible new system design guidelines to improve the safety of future PV systems.

6. Possible Mitigation Strategies to Prevent Fires in Large PV Systems

Owners of large PV systems should consider the following fire mitigation strategies, which, although not comprehensive, are based on an analysis of the probable causes of recent fires. As noted earlier, refinement of these and additional mitigation means may be identified when the Solar ABCs team completes its testing and analysis.

Field experience suggests several steps in the design, installation, and maintenance of a PV system that must be followed to prevent PV system fires. These steps include:

- using proper installation techniques with close attention to wire management, such as taking care to avoid abrading insulation and using correctly-sized wire;
- performing annual preventative maintenance to identify and resolve progressive system damage due to thermal cycling and mechanical vibration;
- using detailed data acquisition to monitor PV system operations and determine if unscheduled maintenance is required; and

- installing additional ground-fault and PV array isolation sensing devices that can be incorporated into the data system to alert operators about potential problems so that maintenance personnel can be dispatched in advance of a failure that could lead to a fire.

6.1 Installation Inspections

The first step in preventing or mitigating ground faults must be taken prior to energizing the array for the first time. Conduct a detailed review of all installation-related issues and develop a punch list to address concerns, including wire management, grounding, and equipment installation for the entire system. Once the punch list has been resolved, the commissioning procedure should include:

- insulation resistance tests on all field-installed conductors, including modules and module wiring;
- open-circuit voltage and polarity tests on all string and feeder circuits;
- operational current readings on all series strings and feeders; and
- thermography of all inverters, disconnects, and combiner boxes at 50 % load or higher as well as thermography of the array to scan for hot spots not caused by shading or other normal temporary conditions.

6.2 Annual Preventative Maintenance

Next, develop a maintenance schedule that establishes consistent inspection, documentation, and maintenance procedures to identify and correct problems before they result in a fire. The fact that a maintenance inspection prior to the Mount Holly fire identified conductor damage that was later recognized as a potential cause of the subsequent fire reveals the value of this type of inspection. This case also highlights the need to adequately train maintenance personnel so that they recognize the visual and testing indicators that a fire is possible.

- Maintenance procedures should include:
- visual inspection of all equipment and field connections in equipment for signs of damage or degradation;
- visual inspection of all accessible electrical junction boxes and raceways to see if conductors are damaged and in need of repair or replacement;
- visual inspection of string conductors to identify any physical damage that is in need of repair and additional protection to prevent progressive damage;
- operating voltage and current tests at defined conditions of irradiance and module temperature to compare output of strings;
- insulation resistance testing of modules, string wiring, and photovoltaic output circuits in the array (s ometimes referred to as a “megger” test); and
- thermography of all inverters, disconnects, and combiner boxes at 50 % load or higher, as well as thermography of the array to scan for hot spots not caused by shading or other normal temporary conditions.

6.3 PV System Monitoring

Another step that owners of large PV systems can take to mitigate the risk of undetected ground faults is to install and use automated performance monitoring instrumentation that recognizes ground faults and other equipment failures as soon as they occur. Performance monitoring and regular data review can be key elements in the safe operation of any power plant. Careful attention to system and subsystem data trends enables early recognition of component failures, and helps to establish effective maintenance schedules that ensure reliable long-term operation. The following is a description of a generic monitoring program based on best practices identified by the author. It is offered as a model and not a solution to all monitoring requirements.

Monitoring systems should include one-second data averaged, recorded, and accurately time-stamped at a minimum of every 15 minutes, and preferably every five minutes. With some averaged values, a minimum and maximum value for each time period can provide insight into the range of values that the average represents.

Averages and minimum/maximum values should be recorded for:

- plane of array irradiance,
- ambient temperature and wind speed,
- alternating current (AC) voltage on each inverter,
- AC power output on each inverter, and
- ground fault current on each inverter.

Items requiring averaged data include:

- direct current (DC) voltage on each inverter,
- DC current on each inverter, and
- morning array insulation resistance (recorded once a day).

Optional items include:

- string currents,
- ground fault current on each PV power source circuit,
- array temperature (back of representative module),
- global horizontal irradiance, and
- wind direction.

One important use of this data is to establish the daily performance index (PI) based on actual versus expected performance. PI is a daily value that is calculated based on irradiance, temperature, wind speed, and system configuration.

A response schedule should be established when the data shows:

- an inverter off-line,
- performance of less than 90 % of expected PI,
- differential current above the prescribed maximum threshold, or
- ground resistance less than the prescribed minimum threshold.

6.4 Possible Retrofits for Existing PV Systems

Finally, the Solar ABCs research will help identify which inverter designs have GFDI schemes susceptible to the blind spot phenomenon and suggest retrofits that may be able to eliminate the blind spot without requiring redesign of the system. Because of the larger power involved, it is expected that larger inverters with the blind spot represent a potential fire hazard that should be addressed. The following protective devices and system retrofit modifications may provide additional protection from grounded conductor ground faults and can be tailored for the leakage current of the specific PV arrays.

6.4.1.1 Differential Current Measurement

The simplest pieces of equipment to add to existing systems are differential current sensors (also known as residual current detectors or RCDs) installed on feeders entering the array combiners on each system. Array conductors can be bundled and run through the current transducers of the RCD, but to the extent possible, it is better to use individual sensors installed on the individual subarray conductors to achieve the highest resolution of differential current. Some commercial residual current monitors can monitor up to 12 current sensors. Employing multiple sensors on a large PV array increases the sensitivity of ground-fault current measurements by making measurements on smaller array segments. Breaking the array into smaller segments allows use of lower trip current levels and significantly reduces the blind spot in large arrays associated with the use of large ground-fault fuse sizes.

6.4.1.2 Insulation Resistance Monitor

A second important piece of equipment needed to eliminate the blind spot is an existing product used to measure the resistance to ground on a PV array. This measurement should be taken every morning prior to the operation of a grounded PV inverter, and should be taken while the array is in open circuit condition. Before determining array resistance to ground, the operator may need to open a contactor to isolate the "grounded" conductor from ground during this measurement. Some inverters have a grounding contactor option. Without such an option on a DC grounded PV array, a separate device that operates independently of the inverter would be necessary.

Once the test has been completed, the array insulation monitor device either will report that the system is free to start normally for the day or it will signal that the ground resistance is below the minimum allowable value and prevent the inverter from starting. In the latter case, the inverter will remain offline, providing indication of a fault and reducing the possibility of a fire.

6.5 Equipment to Consider for New PV Systems

In addition to the equipment recommended for retrofitting existing systems, new system designers should consider the following equipment to improve safety.

6.5 Ungrounded Inverters

The basis for the problem outlined in this document is the fact that the array conductors are solidly grounded, thus making it difficult to detect insulation damage in the grounded conductors. Systems in much of the world do not have conductors solidly grounded on the DC side of the inverter. These ungrounded systems employ more sensitive methods to detect ground faults. Recently, the inverter test standard, UL1741, has been updated to include requirements for transformerless and other ungrounded inverters. Until that standard was updated, few inverter manufacturers were willing to bring ungrounded inverters into the United States. With that technical issue resolved, the door is open for many ungrounded inverter designs to be certified and installed in U.S. systems. Ungrounded inverters (and systems) are not susceptible to the blind spot problem.

6.5.1.1 Contactor Combiners

Differential current sensors and insulation monitors are included in new inverters, but using contactor combiners can provide additional safety. These combiners can de-energize the feeder circuits from the combiner boxes to the array com biners when the AC power is disconnected. As noted earlier, the control circuit for the contactor combiners can be wired through a relay at the inverter controlled by the differential current sensors and the insulation monitor.

Products are also available that provide string-level differential current measurements, and individually isolate a faulted string from the rest of the array. Combined with monitoring, this can provide immediate notification that a fault exists.

6.5.1.2 Arc Fault Detectors

Although the three measures discussed above will go far to eliminate the causes of most fires, they cannot address series arc faults. Series arc faults occur when an electrical connection comes apart under load. These arc faults are particularly problematic because the arc condition is stable and remains until the conductor erodes to the point that it burns away. Unfortunately, if combustible material is present, as it was in both the Bakersfield and Mount Holly fires, the fire will continue burning after the arc extinguishes.

The probability of an arcing fault, though less likely than the faults that caused the Bakersfield and Mount Holly fires, remains high enough to justify installing arc fault detectors. The 2011 National Electrical Code requires arc fault detectors, which are expected to be available in 2012. These units may include contactor combiners or string-level control and feature ground-fault detection functions.

6.5.1.4 Module-Level Controls

Below the string level, the only way to reduce the voltage within the PV array to levels too small to initiate arcing is for electronics to be installed at the PV module. These electronics, often referred to as module-level control, or "smart modules," can be designed to shut off the power from each individual PV module, thus removing the source of fault current and the voltage that could shock a technician or firefighter. Recently introduced products claim to have these features, but testing standards are not yet available to certify that a product can perform this safety function reliably. As adequate certification test procedures are developed, these products should be considered for new installations and even for retrofitting existing systems.

6.6 Implementation of Mitigation Strategies

The Solar ABCs team is evaluating the mitigation approaches described in this report to refine its recommendations for PV system owners. Implementing these strategies will take time, and all the strategies may not be necessary for every PV system. Some of the equipment is not yet on the market, and implementation will require a phased approach.

PV systems with damaged conductors must be identified and repaired as soon as practical. Once the conductor damage is addressed, the differential current monitors can be installed and incorporated into the inverter controls. After these initial steps, owners can add the other measures over time to further enhance safety.

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Inverter Ground-Fault Detection "Blind Spot" and Mitigation Methods

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June 2013

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www.solarabcs.org/blindspot

EXECUTIVE SUMMARY

This final report in the Solar America Board for Codes and Standards (Solar ABCs) "blind spot" series concludes a research program into an important safety issue associated with the design of many U.S. photovoltaic (PV) systems. This safety issue came to light during studies of two well-publicized PV system fires—the first on April 5, 2009, in Bakersfield, California, and the second on April 16, 2011, in Mount Holly, North Carolina.

Based on evidence found at these two fires, traditional, fuse-based ground fault protection schemes do not detect certain ground faults that can occur in grounded PV systems. These undetected faults fall within a detection "blind spot" inherent in the design of most U.S. PV installations.

Over the last twelve months, Solar ABCs has led a broad industry- and stakeholder-based working group to research this problem and evaluate the effectiveness of various mitigation strategies. This research built on earlier work that provided a basic explanation of the cause of the detection blind spot. It includes results of field research conducted to characterize basic array wiring impedance properties and their effects on ground fault detection, circuit modeling, and analyses of high and low impedance faults that may occur throughout the array. It also includes a technical review of the effects of ground fault detection blind spots on different array topologies (grounded, ungrounded, and grounded through the alternating current connection).

Included in this report are recommendations for operational strategies and equipment retrofits that can increase ground fault detection sensitivity and reduce the risk of fire in new and retrofit applications. Early results from large PV systems that have been retrofitted with the recommended protective devices indicate that these devices can substantially reduce the detection blind spot without requiring redesign of the system. The major mitigation strategies and equipment retrofit options presented in this report include:

- following proper installation techniques with close attention to wire management,
- performing routine preventative maintenance to identify and resolve progressive system damage,
- introducing data acquisition and system monitoring at a level sufficient to determine if system integrity has degraded and unscheduled maintenance is required, and
- installing differential current sensors and PV array insulation monitoring devices that can be incorporated into the data system to alert operators to potential problems in advance of conditions that may lead to fire.

Based on the investigations reported here, it is recommended that PV systems with damaged conductors be identified and repaired as soon as possible. It then becomes the task of system operators to weigh the cost of increased system inspections and retrofit hardware against the potential cost and damage of a fire.

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Solar America Board for Codes and Standards

The Solar America Board for Codes and Standards (Solar ABCs) is a collaborative effort among experts to formally gather and prioritize input from the broad spectrum of solar photovoltaic stakeholders including policy makers, manufacturers, installers, and consumers resulting in coordinated recommendations to codes and standards making bodies for existing and new solar technologies. The U.S. Department of Energy funds Solar ABCs as part of its commitment to facilitate widespread adoption of safe, reliable, and cost-effective solar technologies.

Solar America Board for Codes and Standards website:
www.solarabcs.org

Acknowledgments

Solar ABCs wishes to thank the following companies and individuals for their generous support of this project and recognize them for their commitment to public safety. Each of these companies provided Solar ABCs with access to their facilities and paid for the services of both technical and engineering personnel during test and evaluation at these sites. This project would not have been possible without the contributions of:

Southern California Edison

- Darrel Holmes

Duke Energy Corporation

- Michael Butler
- William Moore

SunPower Corporation

- Brad Landers
- Cesar Cabrera II
- Robert Perales
- Wayne Webb

TABLE OF CONTENTS

DISCLAIMER 2

EXECUTIVE SUMMARY 3

AUTHOR BIOGRAPHIES 4

SOLAR AMERICA BOARD FOR CODES AND STANDARDS 6

ACKNOWLEDGMENTS 6

INTRODUCTION 8

SECTION 1—OVERVIEW OF PV SYSTEM GROUND FAULT DETECTION METHODS 10

- Grounded Isolated DC Arrays 10
- Ungrounded Isolated DC Arrays 12
- Ungrounded, Non-Isolated Systems 13
- Hybrid Designs (e.g., Grounded Non-Operating, Non-Isolated Operating) 14

SECTION 2—ARRAY AND INVERTER FIELD TEST RESULTS 16

- Instrumentation and Special Equipment 16
- Results of Field Testing 18
  - Test Results—Residential-Scale Inverters 18
  - Test Results—Commercial-Scale Inverters Operating With Partial Arrays 19
  - Test Results—Commercial-Scale Inverters Operating With Full Arrays 21
  - Test Results—Measurement of Equipment Grounding Conductor Impedance 22
  - Test Results—PV Array Leakage Current Monitoring 23
- SunPower Data 24
- Duke Energy Data 25

SECTION 3—GROUND FAULT BLIND SPOT MODELING AND SIMULATIONS 28

SECTION 4—MITIGATION METHODS AND EQUIPMENT 32

- Mitigation Method 1—Install Residual Current Detector (RCD) on Positive and Negative Array Wiring and Connect to Alarm 34
- Mitigation Method 2—Install Residual Current Detector (RCD) on Positive and Negative Array Wiring and Connect to Emergency Stop of Inverter 34
- Mitigation Method 3—Electronic Current Sensing Relay 35
- Mitigation Method 4—Isolation Monitor and Periodic Check 35
- Mitigation Method 5—Reduce the Size of the Ground Fault Fuse 36
- Mitigation Method 6—Annual Operations and Maintenance 36
- Mitigation Method 7—Use of Arc Fault Detection 38

SECTION 5—OVERVIEW OF CHANGES COMING TO CODES AND STANDARDS IMPACTING GROUND FAULT PROTECTION 39

SECTION 6—CONCLUSIONS 40

ACRONYMS 41

Introduction

This report presents results of a research program that started with the publication in January 2012 of a Solar America Board for Codes and Standards (Solar ABCs) white paper, *The Ground-Fault Protection BLIND SPOT: A Safety Concern for Larger Photovoltaic Systems in the United States.* The white paper introduced an important safety concern in the design of many U.S. photovoltaic (PV) systems, namely conditions that can lead to undetected faults in grounded PV array conductors.[1] This concern came to light during investigations into the role of ground faults in the ignition of two well-publicized PV system fires—the first on April 5, 2009. in Bakersfield, California, and the second on April 16, 2011, in Mount Holly, North Carolina.

PV inverter ground fault protection requirements, methods, and limits have been a significant point of discussion nationally and internationally for some time, and 97 are presently under revision. Under requirements of the *National Electrical Code®* (*NEC*), ground fault protection is required of most PV installations in the United States. The 2014 *NEC* revision cycle is being finalized and Solar ABCs members were instrumental in developing and building consensus for updating PV ground fault protection requirements in the latest code.

Under requirements of the Underwriters Laboratories (UL) 1741 standard, inverters with ground fault detection are evaluated for compliance with specific ground fault detection and interruption tests unless they are marked to indicate that separate ground fault protection must be installed. When investigations uncovered evidence for persistent but undetected ground faults as a condition leading to some PV fires, concern grew about whether the maximum fault current allowed for grounded PV systems during fault conditions is sufficient to protect PV systems from ground faults. Solar ABCs convened a broad industry- and stakeholder-based working group to investigate this concern and to develop a ranked list for effective mitigation methods where needed. The working group developed a research program to:

- investigate—through data sharing with major utilities and PV operating companies—the likelihood of undetected "blind spot" faults occurring in the field;
- demonstrate and characterize the fault current detection "blind spot" in several large, fielded PV inverters;
- measure the impedance of array wiring and equipment grounding conductors in large, fielded PV systems to support modeling and analysis tasks;
- develop accurate simulation models of arrays and systems with high and low impedance faults occurring throughout the array and assess their effects on fault current magnitude and detectability;
- analyze the ground fault detection capabilities of three different PV system types installed in U.S. residential, commercial, and utility-scale PV installations—array ungrounded, array directly grounded (one pole connected to earth), and array (one pole) referenced to ground through a (resistive) connection to the alternating current (AC) ground; and
- provide a list of operational procedures that can reduce the risk of fire as well as a list of retrofit actions that can be taken to increase the sensitivity of electronic ground fault detection.

[1] Technically, the ground fault detector/interrupter is blind to other faults too, e.g., high impedance faults. For details, see Sandia National Laboratories technical report, "Photovoltaic Ground Fault and Blind Spot Electrical Simulations," Sandia National Laboratories Technical Report, 2013, http://energy.sandia.gov/wp/wp-content/gallery/uploads/SAND2013-3459-Photovoltaic-Ground-Fault-and-Blind-Spot-Electrical-Simulations.pdf

Based on the results presented in this report, PV system owners will have to evaluate both the benefits of system retrofits and the risks associated with not implementing various mitigation strategies. Equipped with this understanding, owners will be able to decide which, if any, corrective actions they will implement.

This report is presented in six sections:

- Section 1 is a high-level discussion of the different ground fault detection methods used in different PV array topologies today.
- Section 2 presents a summary of the field test evaluation program performed by Solar ABCs to document and characterize ground fault detection limitations in fielded inverters. Included in this section are additional results of long-term (months, years) monitoring of leakage currents in PV systems in California and North Carolina that reflect the effects of weather conditions (humidity and lightning) on leakage current magnitude.
- Section 3 presents modeling used to examine the effects of reducing the amperage of the ground fault fuse on ground fault detection sensitivity.
- Section 4 presents a matrix of mitigation methods and equipment that can reduce or eliminate the ground fault detection blind spot.
- Section 5 presents an overview of the ongoing revisions to the major codes and standards affecting PV inverters and PV ground fault protection products.
- Section 6 presents conclusions.

[1]Technically, the ground fault detector/interrupter is blind to other faults too, e.g., high impedance faults. For details, see Sandia National Laboratories technical report, "Photovoltaic Ground Fault and Blind Spot Electrical Simulations," Sandia National Laboratories Technical Report, 2013, http://energy.sandia.gov/wp/wp-content/gallery/uploads/SAND2013-3459-Photovoltaic-Ground-Fault-and-Blind-Spot-Electrical-Simulations.pdf

SECTION 1—OVERVIEW OF PV SYSTEM GROUND FAULT DETECTION METHODS

PV systems may be wired in several different configurations with respect to system grounding. The direct current (DC) side of the system may be directly grounded (e.g., one pole connected to earth) or ungrounded, or the array may be grounded through a connection to the AC side ground. Systems also may or may not have galvanic isolation between the DC and AC sides. These design factors influence a system's fault tolerance and response to ground faults, and add complexity to properly implementing ground fault protection. This section addresses the various PV system types seen in U.S. residential, commercial, and power plant PV installations, and their ground fault detection techniques and capabilities.

Grounded Isolated DC Arrays

The most common configuration seen in U.S. residential and commercial PV systems today is the grounded DC array with galvanic isolation from the AC interconnection. This configuration is determined by the inverter, which in most cases grounds the DC side by connecting one pole of the array to ground through a fuse or other overcurrent protection (OCP) device. Under certain conditions, the *NEC* also allows grounded systems in which the array is connected directly to ground without an OCP device, but these are far less common in practice. Galvanic isolation is typically achieved through the use of an isolation transformer interface between the inverter's electronic AC output and the utility connected AC terminals of the unit. Some smaller inverters achieve galvanic isolation using a high-frequency transformer in the DC switching circuit rather than at the utility interface.

The UL 1741 standard specifies the maximum OCP requirements for ground fault detection and interruption in PV inverters. As shown in Table 1, these specifications are dependent on the size of the inverter.

Table 1

UL 1741 Ground Fault Detection Specifications vs. Inverter DC Rating

Inverter DC Rating (kW)	Maximum Ground Fault Current (Amps)
0-25	1
25-50	2
50-100	3
100-250	4
>250	5

Note: kW = kilowatts

Prior to the creation of this table, the standard had no ground fault interruption requirements at all. This change was adopted following instances in which single ground faults on ungrounded array conductors resulted in arcing between cables and metallic conduit. This arcing can result in fire. The OCP settings in the table generally protect well against such faults, but are also rated conservatively to avoid nuisance trips from array leakage current. However, field incidents suggest that additional technical review of these ratings may be useful to most effectively detect or interrupt high impedance faults or faults occurring on the grounded conductor.

A fault between a grounded conductor and ground creates a parallel path for current in that circuit. As shown in Figure 1, some portion of the string current flows in the intended circuit conductors, and some portion flows in the parallel ground circuit between the array and the pole-ground connection in the inverter. Often, the combined impedance of the fault and the ground path is greater than that of the circuit conductors, in which case the ground fault current will be low. In the Figure 1 example, a string current (e.g., 6 amps [A] nominal) divides such that less than half (< 3A) is flowing in the ground circuit back from the inverter. In this example, with a large inverter and a 5A ground fault interrupt fuse, the fault can exist indefinitely without blowing the fuse. The presence of this undetected fault can result in arcing and fire if a second, subsequent ground fault occurs on the ungrounded conductor.

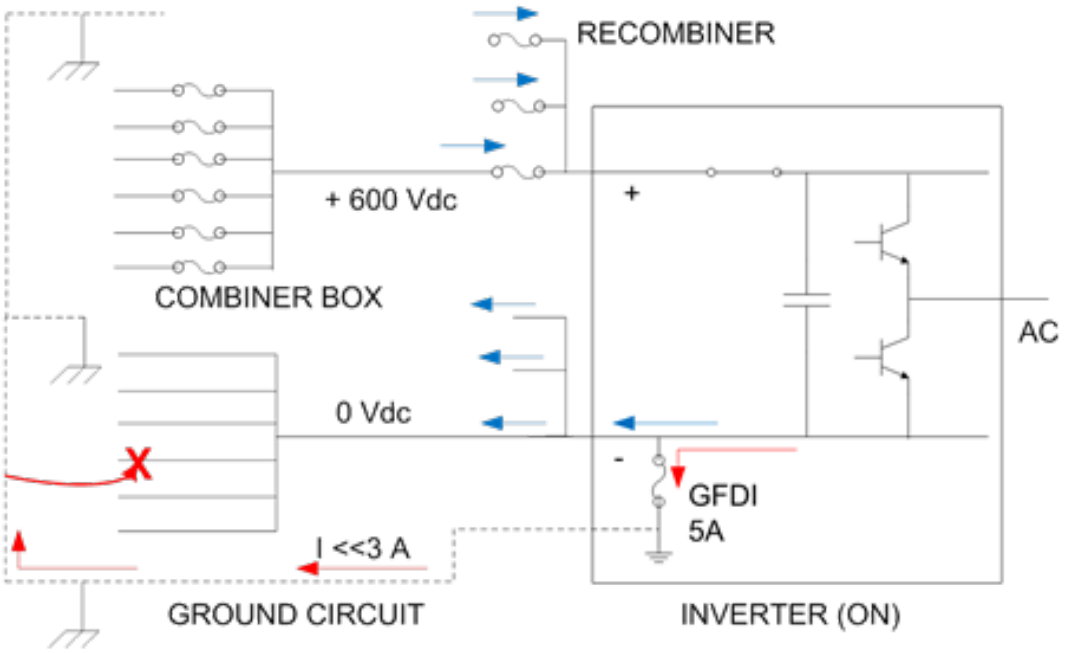

Figure 1. Grounded conductor fault occurring on a PV string or source circuit conductor. Note that Vdc = voltage direct current, AC = alternating current, GFDI = ground fault detector/interrupter, and A = amperes.

Grounded conductor faults on the larger PV output cables (between the combiner box and recombiner or inverter) have a better chance of creating high enough currents to trip a ground fault detector/interrupter (GFDI) fuse, but in some cases, fault impedance may still be sufficient to keep the fault current below the trip rating.

This blind spot problem is not an inherent limitation in the grounded/isolated system configuration, but rather an unintended consequence of the prevailing GFDI method used to deal with multiple faults. The solutions identified later in this report can provide increased sensitivity for detection/interruption capabilities similar to those found in systems using other grounding configuration.

Ungrounded Isolated Systems

The most common array configuration installed outside the United States is ungrounded. That is, neither the positive nor negative DC pole is directly bonded to ground. An ungrounded DC system may have galvanic isolation between the DC and AC side or it may be non-isolated. Large three-phase systems more commonly have galvanic isolation, either with a built-in low voltage transformer or an external medium voltage transformer. The latter approach with medium voltage transformers is also becoming common in U.S. power plants.

As we have discussed, the ground fault detection blind spot is much less applicable in ungrounded systems that incorporate isolation monitoring and lower ground fault thresholds. Without an intentionally grounded array conductor, ground faults on either conductor are easy to identify with appropriately chosen and properly adjusted isolation measurement devices. However, an ungrounded array with inadequate attention paid to ground faults is susceptible to dramatic failures the same way a grounded system is under the blind spot scenario. Figure 2 shows the schematic for an ungrounded array with an isolated inverter. The poles are not explicitly referenced to ground, but if measured with a voltmeter, a healthy array will tend to have a balanced positive and negative voltage around zero potential.

Ground fault detection in ungrounded arrays is typically achieved by measuring the insulation resistance of each pole relative to ground (commonly referred to as Iso measurements). In a healthy, moderate sized array, the Iso resistance should be in the hundreds or thousands of kilo-ohms (kohm). A ground fault is detected when the impedance to ground of either pole drops to a low level. There are different trip thresholds depending on the inverter and size of the array, but faults of one kohm or less are unambiguously detected and flagged as faults. This is one of the more sensitive and robust methods of ground fault detection.

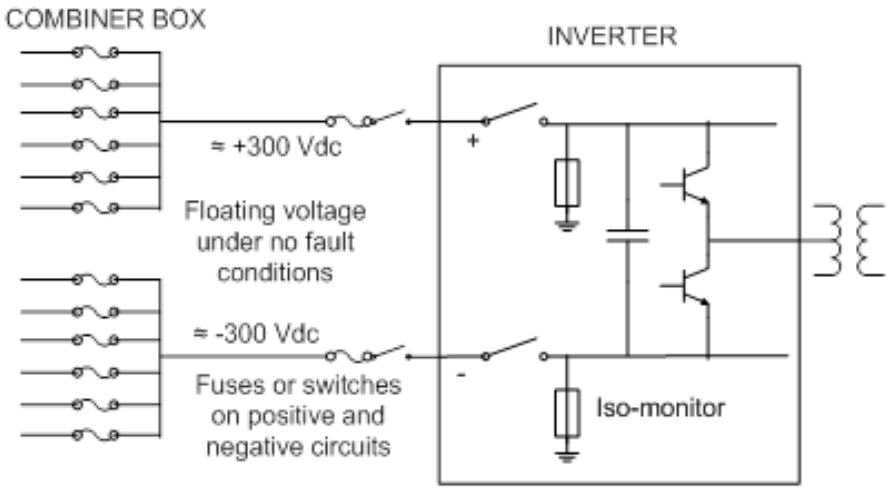

Figure 2. Ungrounded array with AC isolation. Note that Vdc = voltage direct current.

The action taken following fault detection is important. The first fault will not cause any fault current to flow. This is only true with isolated inverters. Non-isolated inverters will cause large fault currents from the utility. Effectively, the ground fault has turned an ungrounded system into a grounded system. But,

as with the blind spot fault, if a subsequent fault occurs on the opposite pole, a short circuit is created that may not be readily interrupted by the array OCP devices. Therefore, it is essential to respond to a first fault in an ungrounded system as one would in a grounded system by either shutting the inverter down or isolating the portion of the array that has the fault.

UL issued a Certification Requirement Decision (CRD), on July 29, 2012, that includes requirements for *Isolated Inverters Intended for Use with Ungrounded PV Arrays.*[2] This CRD includes PV array isolation measurement requirements prior to inverter operation and also includes low level ground fault current trip limits based upon the kilovolt-amps (kVA) size of the inverter. This CRD results in a significant increase in ground fault detection sensitivity and improvement in response time. Multiple inverters from several manufacturers have already been listed for compliance with this CRD.

Ungrounded, Non-Isolated Systems

As mentioned above, ungrounded DC arrays may also be operated without galvanic isolation from the AC wiring. These are known as non-isolated systems. The circuit configuration for non-isolated systems is similar to the one shown in Figure 2, but without the AC transformer. The impact is that during operation, the DC pole voltages relative to ground vary in response to inverter switching devices connecting and disconnecting the DC bus to the AC poles. So, while the PV array/DC input is not directly bonded to ground, its voltage relative to ground fluctuates at the inverter switching frequency. A grounded DC system cannot use a non-isolated inverter because the PV ground bond connection would cause a short circuit for the ground-referenced AC utility connection through the inverter as soon as the inverter began operating.

As with ungrounded isolated systems, the blind spot phenomenon (ground fault in the grounded conductor) is not applicable, because there is no grounded conductor. Ground fault detection is achieved differently than with the isolated systems. When the inverter is first turned on, or in the mornings before the inverter begins operation, an isolation measurement is performed on both the PV array positive and negative poles. If a low impedance to ground is detected (as defined in the ungrounded isolated case), the inverter will stop operating and indicate a ground fault. The fault must be located and cleared before the inverter can operate.

When the inverter is operating, Iso measurements cannot be taken because of the continually changing voltage reference on each pole to ground. Therefore, a residual current measurement is made, generally on the AC side, to look for any imbalance in current going in versus current going out. This will detect faults within the inverter as well as ground faults in the DC system. Because the fault current is sourced on the AC side, the residual current detection can be highly sensitive to ground faults. This two-pronged approach to identifying faults both before and during operation is one of the more robust GFDI detection methods available for any system topology.

[2]UL 1741. (2010, January 28). Edition 2. New sections 109 to 112.

UL issued a CRD on April 26, 2010, that includes requirements for *Non-Isolated EPS Interactive PV Inverters Rated Less Than 30kVA*.[3] These requirements were written to be consistent with European requirements for non-isolated PV inverters and an early draft of the International Electrotechnical Commission (IEC) 62109-2. The requirements include PV array isolation measurements requirements prior to inverter operation. They also include multiple low milliamp (mA) level ground fault current trip limits and trip times. These requirements are similar to the protection methodologies used by IEC-compliant residual current detector (RCD) products such as those provided by the Bender protection relay. Multiple inverters from several manufacturers have already been listed for compliance with this CRD. Non-Isolated inverter requirements for systems larger than 30 kilovolt-amps (kVA) are included in IEC 62109, which is in the process of being adopted in the United States as UL 62109 to replace UL 1741 for PV inverters and other PV power electronics.

Hybrid Designs (e.g., Grounded Non-Operating, Non-Isolated Operating)

At least one major inverter manufacturer employs a hybrid grounding approach. This manufacturer's bipolar inverter operates with half of the PV array connected as a negative-grounded system, and the other half connected as a positive-grounded system. When the inverter is not operating (not sourcing AC power to the grid), the positive and negative array neutrals are isolated from each other and functionally grounded using GFDI fuses as described in the section on grounded isolated systems. When the inverter is operating and producing power, the neutrals of the positive and negative arrays are referenced to the AC neutral/ground of the utility interface (see Figure 3). The AC ground referencing is not a hard connection, but is achieved through the switching circuitry in the power conversion stage of the inverter. This method ensures that the neutral circuits are effectively held to low and safe potential levels relative to ground.

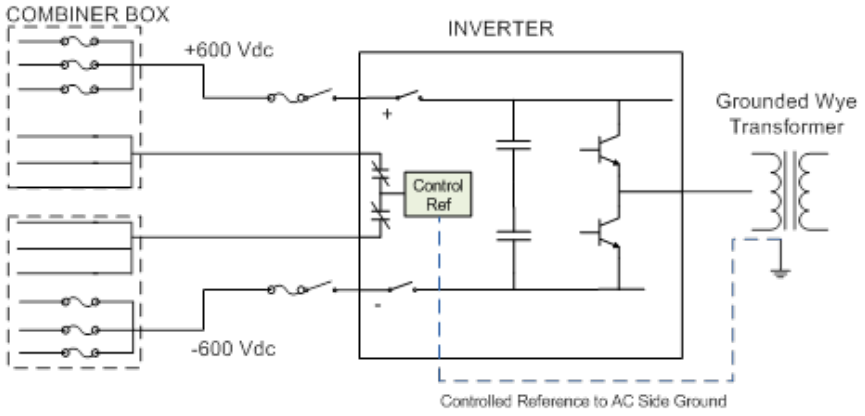

Figure 3. Grounding approach in hybrid bipolar inverter during operation (offline grounding not shown). Note that Vdc = voltage direct current and AC = alternating current.

[3]UL 1741. (2010, January 28). Edition 2. New proposed sections 87 to 100.

A low AC voltage is superimposed on the neutral to ground circuit, which enables fairly sensitive ground fault detection. A ground fault on a grounded string conductor causes fault current to flow from the AC side (a much greater source of current than the PV array) and this can be significant enough to be detected in the inverter either as a DC ground fault or a zero-sequence AC fault. The hybrid bipolar inverter has demonstrated this sensitivity, notably in project startup situations where string conductor faults cause trips and must be identified and cleared before the system can be put into operation.

During field tests at a site with a hybrid inverter, the inverter tripped in response to grounded string conductor faults with zero impedance, but was inconsistent with a fault impedance setting of one ohm or greater. There are many factors that drive the level of sensitivity within a given array, but field results indicate that, although not as sensitive as some of the other methods recommended in this report, the hybrid inverter can provide greater sensitivity in ground fault detection than the standard grounded-isolated inverter configuration.

SECTION 2—ARRAY AND INVERTER FIELD TEST RESULTS

The overarching goals of the field test program were to demonstrate and characterize the ground fault detection blind spot. A formal test plan was drafted and reviewed by Solar ABCs members and the GFDI working group. The major objectives of field testing were:

- Use megger testing to determine the presence of ground faults in any existing array positive and negative conductor (array floating) and measure the impedance of the equipment grounding conductor.
- Use an RCD to measure the normal operational differences in current (i.e., the presence of leakage current) flowing in positive and negative array conductors (array operating).
- Use an oscilloscope to measure magnitude of AC waveforms on the ground fault fuse during normal system operation (array operating).
- Introduce an intentional, "controlled" ground fault into the grounded conductor of an array (or string). Verify that the inverter does not detect the fault and continues to operate. Measure the fault current directly at the site of the fault and through the ground fault fuse (array operating). Use an oscilloscope to measure and record AC waveforms on the ground fault fuse circuit during this test.

Throughout the testing phase, an effort was made to test a wide variety of inverters to demonstrate either the universality of the detection blind spot or to identify inverters with advanced ground fault detection circuitry that were resistant to the blind spot phenomenon.

Instrumentation and Special Equipment

Creating an intentional fault within a large PV array is dangerous and has the potential to ignite a fire. For safety and repeatability, a dedicated piece of equipment was designed for creating faults between the array's grounded conductor and equipment ground. This device, referred to as a ground fault appliance (GFA) is shown in Figure 4. The GFA includes a fused disconnect switch and can connect to array wiring through an inline T-cable (with either MC3 or MC4 connectors). It was used to sequentially introduce any of four preset values of resistance (short circuit, 1 ohm, 5 ohms, 10 ohms) between an array conductor and ground. The schematic for the GFA in its installed condition is shown in Figure 5.

Figure 4. Ground fault appliance with T-cables and meter used to introduce ground faults within an array.

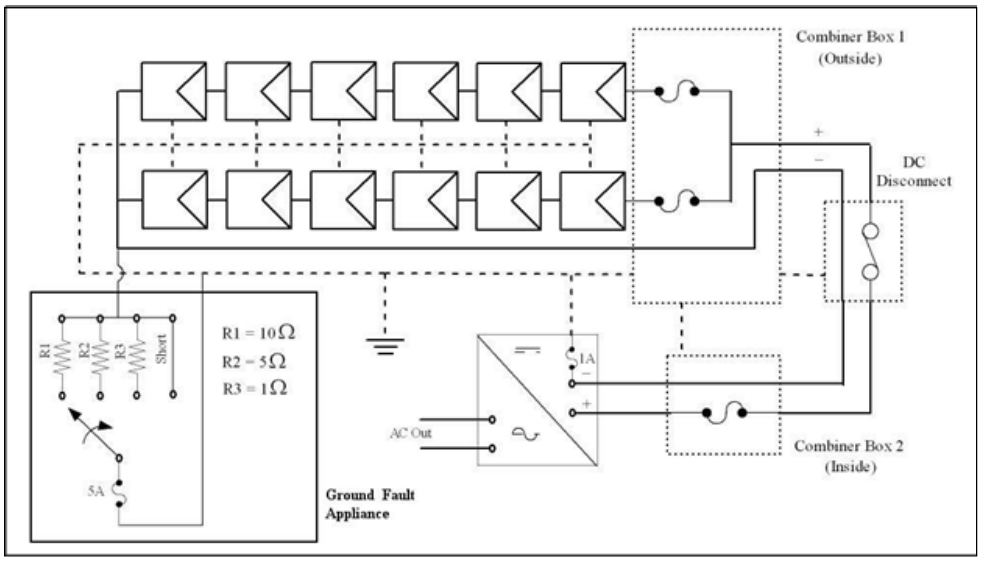

Figure 5. Schematic diagram of the ground fault appliance installed for testing. Note that DC = direct current, AC = alternating current, and Ω = ohm.

The GFA includes a built-in 5A:50 millivolt (mV) precision current shunt for measuring fault current at the array. The 5A:50mV precision current shunt will effectively change the fault resistance from 0, 1, 5, and 10 ohms to a slightly larger value (0.01, 1.01, 5.01, 10.01 ohms) based on the shunt resistance (0.01 ohm for the 5A:50mV). The switches and other components in the GFA will also have some internal resistance. In all the cases, this value falls into the noise of the resistance of the equipment grounding conductor (EGC) path.

For measuring fault currents at the inverter, an RCD (Bender RCMS460-D-2) was used. Before testing, both the positive and negative conductors from selected strings were routed through the RCD's current transducer. During normal operation, the current in both conductors of a string will be equal. The RCD measures and reports any difference between the two currents. A measured difference represents current flowing outside one of the conductors (e.g., through module frames, the EGC, etc.). Current outside the conductor can be the result of either normal module leakage current or fault current from any source such as modules, wiring, combiners, etc.

Results of Field Testing

Field tests were conducted on PV systems at the following sites:

- Sandia National Laboratories, Albuquerque, New Mexico (March 2012);
- Fontana, California (May 2012);
- Union City, California, and Fresno, California (June 2012); and
- San Leandro, California, and Davis, California (August 2012).

Twelve inverters from eight different manufacturers were tested during this program. In every case, the test involved introducing a ground fault into one of the grounded conductors of the array through four steps of decreasing resistance, from 10 ohms to short circuit. Most of the inverters tested continued to operate normally in the presence of all of the introduced faults. In two cases, the inverter under test operated normally with the higher resistance faults, then tripped offline once fault resistance decreased and fault current rose beyond its detectability threshold.

Test Results—Residential-Scale Inverters

The first tests were conducted on residential-scale inverters at Sandia National Laboratories (Sandia). Sandia engineers provided access to the Distributed Energy Technologies Laboratory (DETL). Design of the DETL is unique and allowed a single array to be used for testing a selection of four different inverters. Table 2 shows results of testing one of the inverters (identified only as Inverter C in this report), a 5 kilowatt (kW) single phase unit. During testing, fault current was measured both at the array with a shunt in the faulted circuit and at the inverter with an RCD around array positive and negative conductors.

All four residential-scale inverters continued normal operation in the presence of a ground fault between a grounded circuit conductor and the grounding system with current at or below their ground fault fuse values (1A in all cases). One inverter continued operation until fault current reached approximately 850 mA when it tripped offline without blowing the 1A ground fault fuse. This inverter uses a current transducer on the ground fault circuit in addition to the inline 1A fuse.

Table 2

Ground Fault Current Measurements, Residential-Scale Inverter C (Sandia)

Ground Fault Resistance Value	Fault Current at the Array (Fluke meter)	Residual Current at the Inverter (Bender Device)	Inverter Operating (Y/N)
10 Ω	51 mA	47 mA	Y
5 Ω	96 mA	91 mA	Y
1 Ω	40 mA	342 mA	Y
0 Ω (short)	850 mA	>600 mA	Y

Note: Ω = ohm, mA = milliampere

Test Results—Commercial-Scale Inverters Operating With Partial Arrays

Several rounds of tests were conducted on large PV systems and inverters. These tests were made possible by the generous partnership of two companies, Southern California Edison (SCE) and SunPower Corporation. SCE provided the support of an SCE electrician and access to several PV systems that the utility owns and operates. SunPower provided similar access and service to several systems that the company has installed and operates for others. SunPower engineers also conducted supplemental tests in support of this project and shared test results with Solar ABCs.

Between one and three strings were used to energize the inverter during most tests. As before, ground fault current was measured at the site of the fault (in the array) and at the inverter (via the RCD). Figure 6 shows the RCD (Bender) current transducer installed around a single string during testing. Figure 7 shows the installation of the GFA within a string combiner box on the roof. In this case, the GFA was used to introduce controlled ground faults within the combiner box.

Figure 6. Bender current transducer installed around positive and negative string conductors

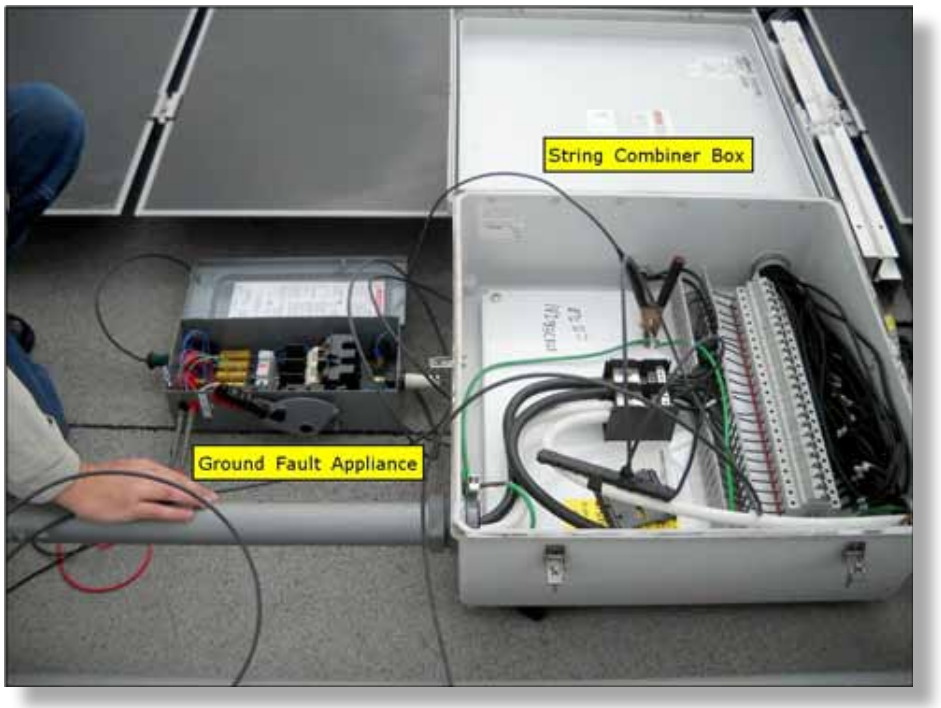

Figure 7. Ground fault appliance installed in string combiner box during testing.

Ground fault testing was conducted on 500 kW, 225 kW, and 200 kW inverters from four manufacturers. In all cases, inverters continued normal operation in the presence of introduced ground fault between a grounded conductor and the grounding system with current at or below their ground fault fuse values (5A in all cases). Table 3 presents results of the ground fault testing on one 500 kW inverter. These results are typical of most of the tests performed.

Table 3

Ground Fault Current Measurements, Industrial-Scale Inverter 2 (SCE)

Ground Fault Resistance Value	Fault Current at the Array (Fluke meter)	Residual Current at the Inverter (Bender)	Fault Current Through the Inverter Ground Fault Fuse Shunt (Fluke meter)	Inverter Operating (Y/N)
10 Ω	97 mA	98 mA	93 mA	Y
5 Ω	159 mA	167 mA	157 mA	Y
1 Ω	660 mA	>600 mA	689 mA	Y
0 Ω (short)	3,880 mA	>600 mA	3,910 mA	Y

Note: Ω = ohm, mA = milliampere

Test Results—Commercial-Scale Inverters Operating With Full Arrays

Although testing with a reduced number of strings was desirable for safety reasons, engineers from SunPower used a full array to retest one of the systems that had been tested earlier using only a few strings. This system was chosen for retest specifically because its inverter incorporates electronic ground fault detection circuitry in addition to the ground fault fuse. The retest was performed to investigate whether, in a real-world situation with full array current available, the ground fault detection threshold will be reached quickly and sustained operation in the presence of the fault will be as likely to occur. Table 4 presents results of testing Industrial-scale Inverter 1 in August when only three strings of the array were used to energize the inverter. Table 5 presents results of retesting this inverter in November with the full 500 kW array enabled.

Table 4

Ground Fault Current, Three Strings Enabled, Industrial-Scale Inverter 1 (SunPower)

Ground Fault Resistance Value	Fault Current at the Array (Fluke meter)	Inverter Operating (Y/N)
10 Ω	50 mA	Y
5 Ω	60 mA	Y
1 Ω	160 mA	Y
0 Ω (short)	1.02A	Y

Note: Ω = ohm, mA = milliampere, A = ampere

Table 5

Ground Fault Current, Full Array Enabled, Industrial-Scale Inverter 1 (SunPower)

Ground Fault Resistance Value	Fault Current at the Array (Fluke meter)	Inverter Operating (Y/N)
10 Ω	520 mA	Y
5 Ω	1.14A	Y
1 Ω	2.90A	Y
0 Ω (short)	-	Inverter Tripped

Note: Ω = ohm, mA = milliampere, A = ampere

Testing demonstrated that ground fault currents are larger when the full array is enabled. Ground fault simulation program with integrated circuit emphasis (SPICE) modeling by Sandia scientists also shows that the likelihood of a ground fault being detected improves with an increasing number of strings in the circuit. The indication is that for inverters, which sense ground faults through electronic circuitry (and not simply a fuse), testing with the full array is necessary to obtain valid results for the sensitivity of the inverter's ground fault detection. Even under full array conditions, sustained operation in the presence of a non-zero ohm ground fault was still observed.

Test Results—Measurement of Equipment Grounding Conductor Impedance

The EGC for a PV array connects all exposed metal of the array to a copper conductor that is bonded to earth ground at the inverter. Therefore, current flowing in the EGC can follow the copper conductor or any of the parallel paths represented by array frames, racks, or metal conduit. During field testing, measurements were made to determine the impedance of the EGC in a given PV system.

This system uses a positive grounded array. During testing, one string of the array was opened at the positive end. The first measurement taken was of the impedance through the positive home run wiring of this string, to the inverter, and back via the return through the EGC. Figure 8 shows the schematic for this circuit.

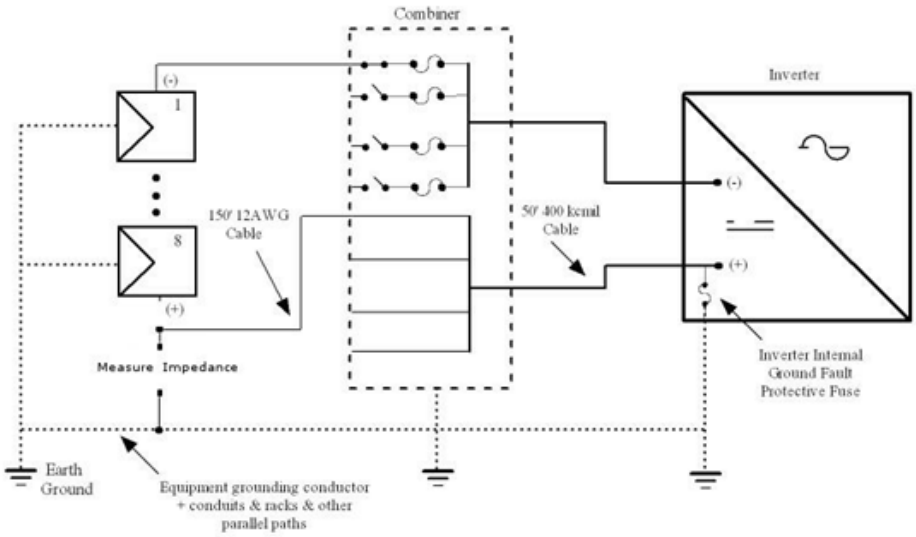

Figure 8. Impedance measurement of array positive home run wiring through inverter and EGC return. Note that AWG = American wire gauge and kcmil = thousand circular mils.

The home run wiring consisted of approximately 150 feet of 12 American wire gauge (AWG) cable to a combiner box followed by approximately 50 feet of 400 thousand circular mils (kcmil) cable from this box to the inverter. The return path was through the equipment grounding conductor and any grounded components of the system. The impedance measured for this circuit was 0.34 ohm. The resistance of the two cables (the positive conductors) was then calculated based on data sheet values of ohms/ft times the estimated length of each cable. Figure 9 shows the calculated resistances of the cables in this circuit and the resulting calculated resistance of the return path from the inverter through the EGC. Resistance of the return path (EGC) is estimated to be 0.041 ohm.

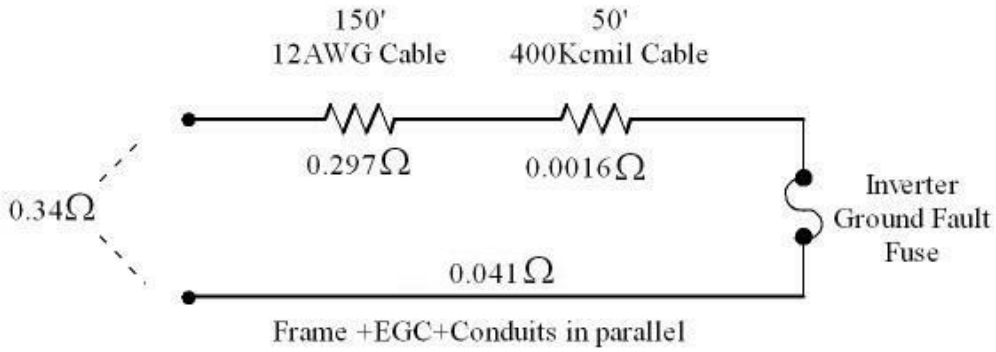

Figure 9. Derived impedance values for positive home run cabling and EGC return. Note that Ω = ohm, AWG = American wire gauge, kcmil = thousand circular mils, and EGC = equipment grounding conductor.

Test Results—PV Array Leakage Current Monitoring

A PV array may introduce current into the EGC as a result of a fault (an unintended connection between conductor and ground) or from the unavoidable flow of current through non-ideal insulating materials of the cables, PV modules, and other array components. This current is referred to as leakage current. One challenge for every inverter is that it must reliably disconnect under true fault conditions without incurring "nuisance" trips from leakage currents. Studies of module leakage current[4] show that it is small relative to the array output current and is a function of moisture, array voltage, and temperature. We can estimate an expected maximum value for typical array-level leakage currents if we assume the modules have met the standard UL 1703, IEC 61646, or IEC 61215. Modules that meet these standards must demonstrate least 40 megaohms per square meter isolation to their grounded frame. For a typical module of approximately 1.2 square meters operating at 600 volts (V), the module would yield approximately 11 microamperes per kW. Therefore, we would expect a 500 kW array (of new modules) to experience a maximum of approximately 56 mA of leakage current.

Few studies have been performed in the United States to record leakage currents occurring under normal conditions in grounded PV systems. However, two U.S. companies that responded to early concerns regarding blind spot detection by installing RCDs on selected PV systems were able to supply leakage current data for this report.

In response to the Mount Holly fire in April 2010, Duke Energy elected to install RCDs on all of Duke's roof-mounted and several ground-mounted PV systems in North Carolina. Solar ABCs is grateful to Duke Energy for making data available from these sites, which include 14 inverters with a total of 45 array segments representing about 3.5 megawatts of PV. The circuit sizes for the Duke systems ranged from 50 kW to 161 kW. All monitored systems were crystalline silicon technology that included both standard and back-contact cell constructions.

[4] del Cueto and McMahon, *Analysis of Leakage Currents in Photovoltaic Modules under High-Voltage Bias in the Field,* Prog. Photovolt: Res. Appl. 2002; 10:15-28

SunPower Corporation also elected to install RCDs on several PV systems that it has installed and continues to operate. For this report, SunPower generously made available data and analyses of the data for four inverters monitored at two different sites.

Before discussing the results of leakage current monitoring by RCDs, it deserves note that in August 2011, one of the RCDs installed by Duke Energy tripped its inverter offline as a result of a fault that was subsequently found to have occurred on a grounded conductor. That fault was immediately repaired. One week later the system tripped on a second fault. This one was identified as having occurred on a non-grounded conductor. This sequence of events is identical to those that initiated the Mount Holly fire. In this case, detection and repair of the first fault on the grounded conductor likely prevented another fire.

SunPower Data

SunPower Corporation provided data from two different sites in California. Site One operates at 1,000 V maximum and uses two 750 kW inverters. Site Two operates at 600 V maximum and uses two 500 kW inverters from a different manufacturer than Site One. Analysis of these data is ongoing, but some results can be reported here.

Figure 10 shows the data recorded by the RCD at Site One on a typical high irradiance day. Figure 11 shows the data recorded on a low irradiance day. The ground current presented in these figures was filtered with a moving average window to remove noise introduced by the RCD installed at this site.

Recorded data from this site show that ground current ramps up initially with PV system voltage to approximately 7 to 10 mA, but it does not stop once system voltage stabilizes. Ground current continues to increase to 15 mA as system current increases with irradiance. Experiments in which the inverter transitioned from offline to inverting showed this 5 mA increase as a step function, indicating it is directly related to inverter current magnitude as opposed to module temperature (which does not change in a similar stepwise pattern).

Ground current data for Site One show infrequent, short duration spikes of 30 to 45 mA. These spikes appear in the records as single data points. SunPower programmed the RCDs to sample data once every 15 seconds. Single point spikes in ground current, therefore, indicate a transient with a duration less than 15 seconds. These transients appear to be most prevalent at the beginning and end of the day. The source of these spikes in the recorded ground current is not yet known, but is believed to be caused by the inverter turning on and off.

The SunPower data show little or no increase in ground current with moisture. Ground current recorded during rainfall showed no difference from data recorded on dry days.

Data analysis continues for Site Two. Similar trends have been observed, although the magnitude of ground current at Site Two is roughly three times that of Site One when the inverter is operating.

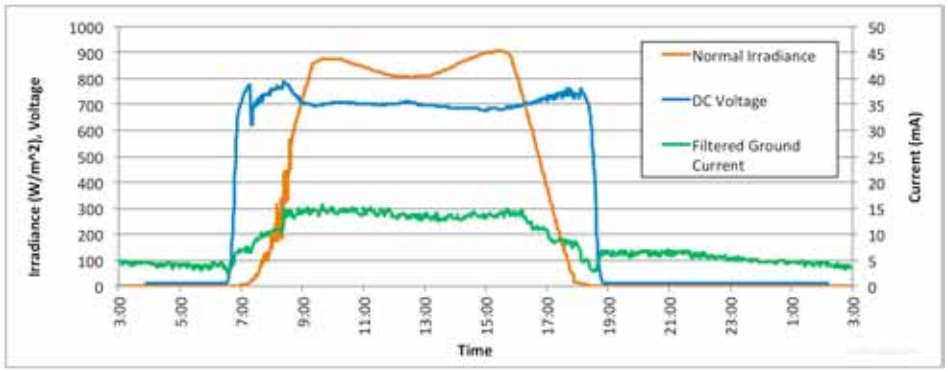

Figure 10. Ground current for typical high irradiance Day—approximately 15 mA.

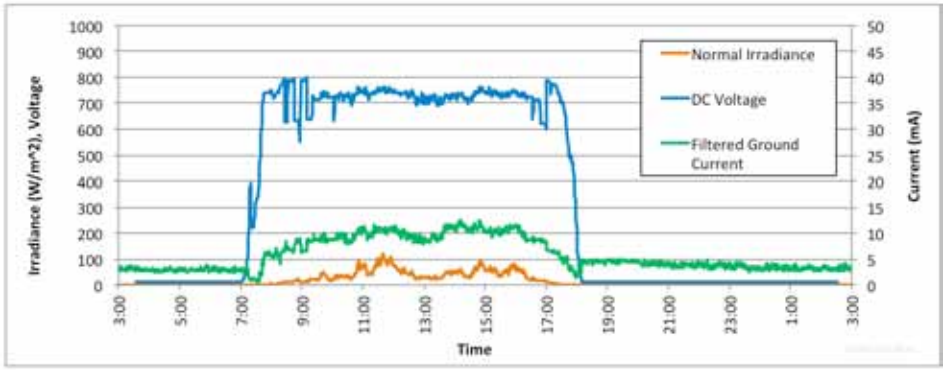

Figure 11. Ground current for typical low irradiance day—approximately 10 mA.

Duke Energy Data

Among the 45 PV array segments from which data were gathered by Duke Energy, the various RCDs were programmed to make logger recordings at 10%, 35%, 70%, and 75% change between each ground current reading and the previous one. The reason for the different settings was related to the monitoring requirements associated with each site. A setting of 35% change was found to be a value that is sensitive enough for short-term data monitoring while taking between one and three months to fill the logger buffer (300 data points before overwriting the oldest records with new ones).

The RCDs on the Duke Energy-owned systems default trip setpoint was 300 mA, but after extensive testing, most RCDs were set to trip the inverter offline when ground current exceeded 60 mA. Among the many sites, the ground current records from the RCDs typically recorded ground current readings in the 20 to 50 mA range. However, some elevated readings were also recorded at times at some sites. Because many of these high current readings were recorded at night, it was hypothesized that they were associated with lightning and electrical storm activity in the area of the PV system. To confirm this hypothesis, Duke Energy cross-referenced the periods of high ground current against a storm activity database in which time, location, and current levels of lightning strikes are recorded. This analysis showed that many periods of elevated ground current readings were positively correlated with recorded activity of storms and lightning in the affected area. However, because the clocks in the RCDs were not set to the atomic clock time standard, the RCD data cannot be positively correlated to known lightning strikes.

Current sensors for the different Duke Energy RCDs were installed around varying numbers of array string conductors (i.e, they were monitoring array segments of different sizes). Figure 12 shows the highest RCD ground current readings normalized to present mA per kilowatt of monitored array.

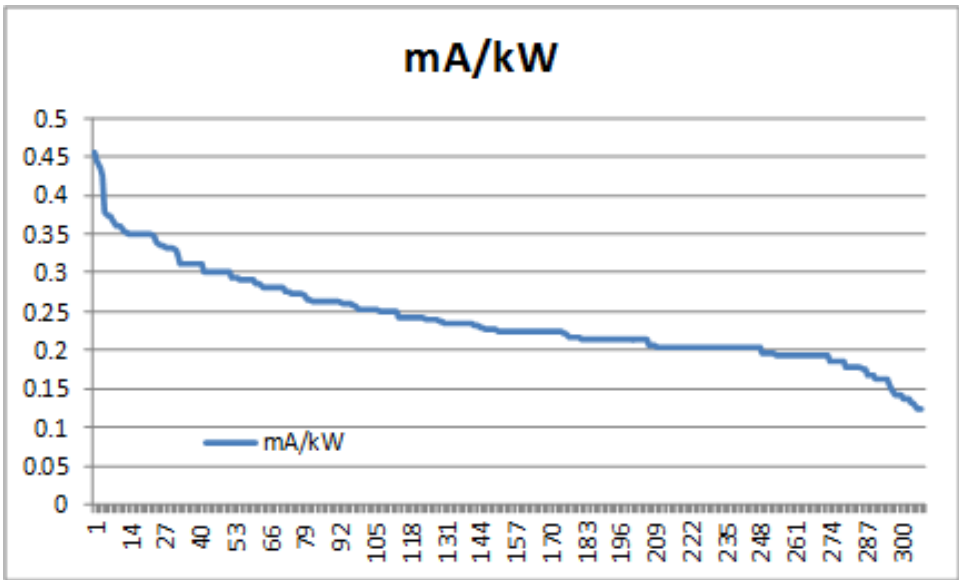

Figure 12. Highest recorded ground current—Data normalized to show current per kilowatt of array. Note: mA/kW = milliamp per kilowatt.

Based on the calculated values of ground current per kilowatt of array segment, the array segment size needed to cause a 300 mA trip was calculated, shown in Figure 13. This calculation assumes that all of the data recorded during a storm event causes a simultaneous flow of current and results in a conservative assumption.

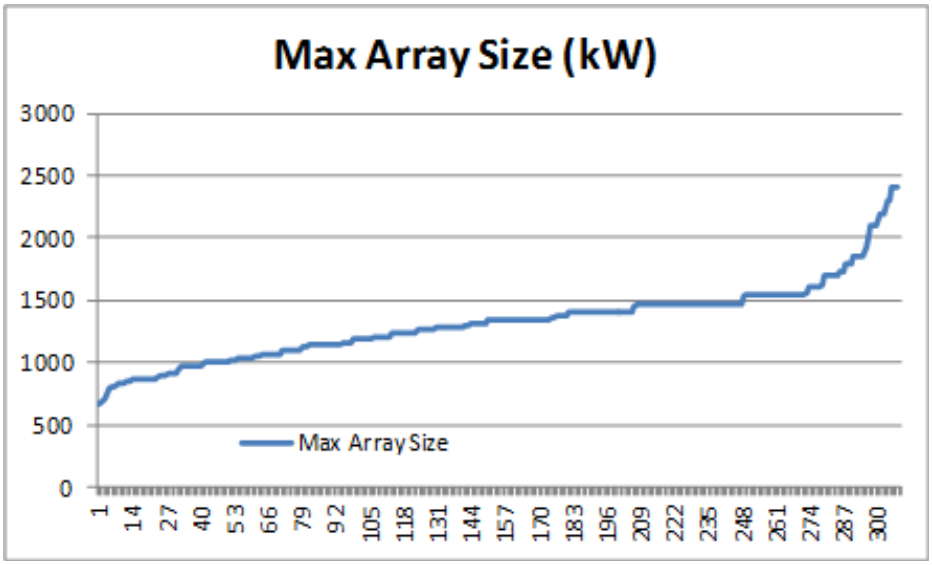

Figure 13. Array size required to produce a 300 mA ground current. Note that kW = kilowatt.

When establishing fault current trip limits, the effects of lightning on ground current must also be considered. Figure 14 shows an inverter (designated CK2) that had elevated ground current readings during major storm activity. The plot shows the magnitude and polarity of the lightning current based on lightning strike data recorded in the immediate vicinity. Ground currents increase before lightning activity initiates and may be due to current dissipation from the array prior to local lightning strikes. Alternatively, the more distant lightning strikes near large transmission lines adjacent to the facility may induce the observed current. Regardless, it is clear from the examination of the data that lightning has a direct impact on the ground current readings.

Because lightning and its impacts are very short in duration, its effects can be filtered out by extending the measurement duration. SunPower programmed their measurement devices to record 10 second moving averages before determining a trip had occurred. A moving average such as this effectively eliminates false trips due to short duration lightning transients. Additional research in lightning prone areas is needed to bear out this assumption.

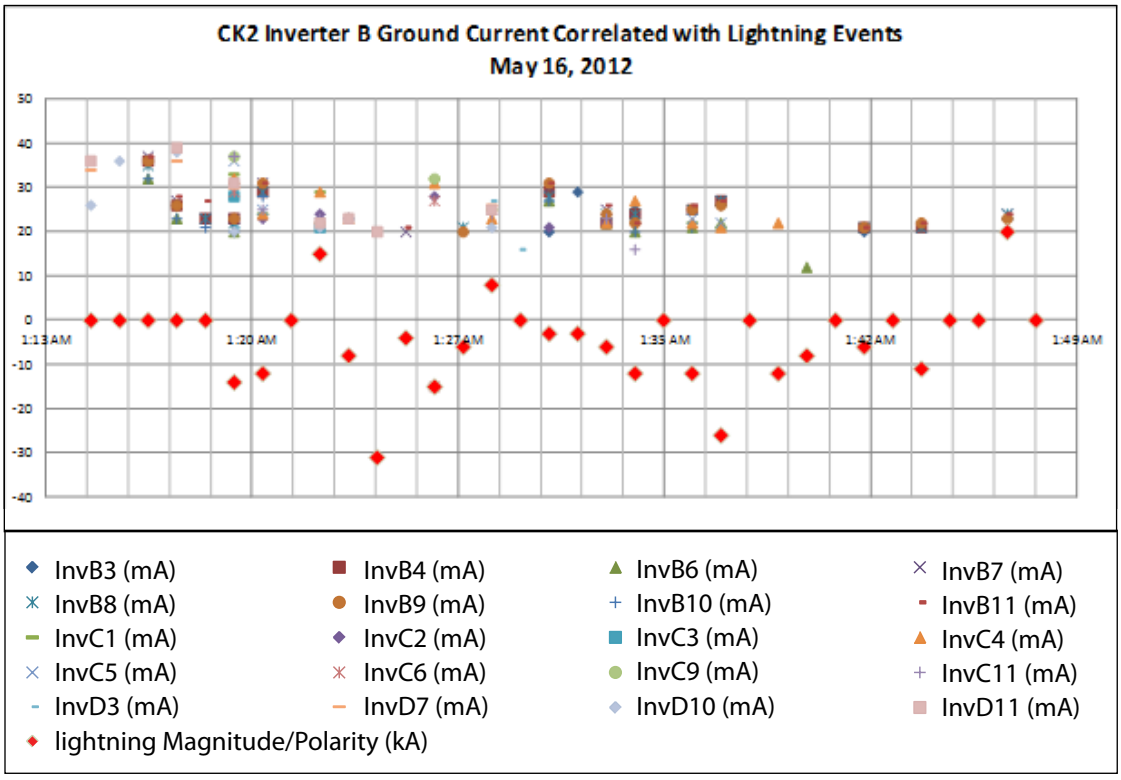

Figure 14. Effects of lightning on ground current for Duke Energy system CK2.

SECTION 3—GROUND FAULT BLIND SPOT MODELING AND SIMULATIONS

Theoretical treatment of blind spot faults and their effect on ground fault current has been explored at Sandia using both analytical and simulation methods. This section of the report draws from two recent publications by Sandia scientists. The first, a Sandia technical report,[5] introduces the array model in detail and explores the effects of both ground faults and blind spot faults on module and array operation. The second, a Solar ABCs Report,[6] focuses solely on blind spot faults and the inherent limitations of traditional fuse-based GFDIs.

In both of these works, circuit analysis was used to verify an analytical equation for the GFDI current in the grounded conductor fault scenario. This analytical solution shows that GFDI current is a function of array size, parasitic cabling impedances, module leakage current, and GFDI resistance. The analytical solution was corroborated with circuit simulations using SPICE. Figure 15 shows an example of current flow from a SPICE simulation for a 101-string array with a 1 ohm blind spot fault and a 1A GFDI fuse. For this array state, the GFDI current is below the 1A fuse threshold, indicating an undetected blind spot fault.

[5]Flicker, J. & Johnson, J. (2013). *Photovoltaic Ground Fault and Blind Spot Electrical Simulations.* Sandia National Laboratories Technical Report. http://energy.sandia.gov/wp/wp-content/gallery/uploads/SAND2013-3459-Photovoltaic-Ground-Fault-and-Blind-Spot-Electrical-Simulations.pdf

[6]Flicker, J. & Johnson, J. (2013). *Analysis of Fuses for "Blind Spot" Ground Fault Detection in Photovoltaic Power Systems.* Solar ABCs. www.solarabcs.org/blindspot

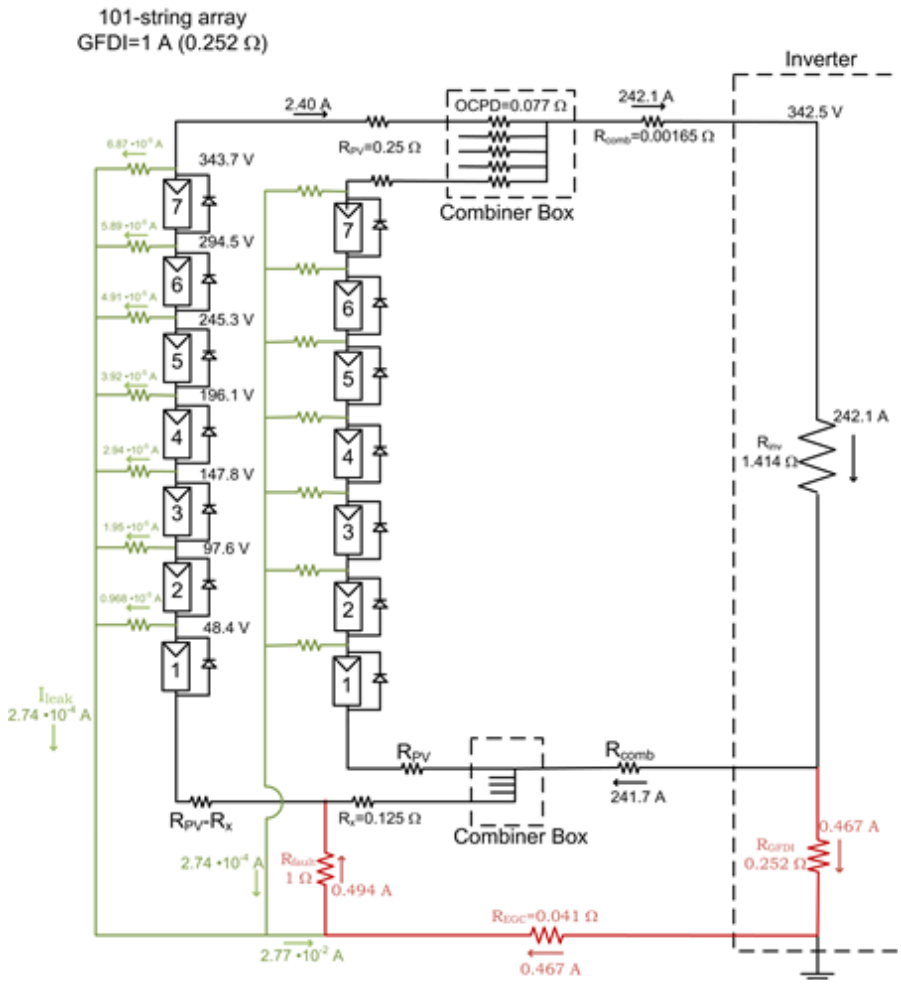

Figure 15. State of a 101-string array composed of strings of seven 200 W modules in series during a 1 ohm blind spot fault as determined by SPICE simulation. Note that array elements are colored black, including parasitic cabling resistances from the PV cabling (R_{PV}), combiner cabling (R_{comb}), overcurrent protection device (OCPD), and ground fault detector and interrupter (GFDI). Leakage current path is green and fault path is red.

The analytical solution to the GFDI current indicates that in order to minimize the ground fault blind spot, the resistance of the GFDI must be considered in addition to the trip point. Unfortunately, as the fuse trip point decreases, the fuse resistance increases dramatically (Figure 16). Therefore, there is a critical limit in fuse size, below which a smaller fuse leads to less fault current passing through the GFDI and a larger ground fault blind spot.

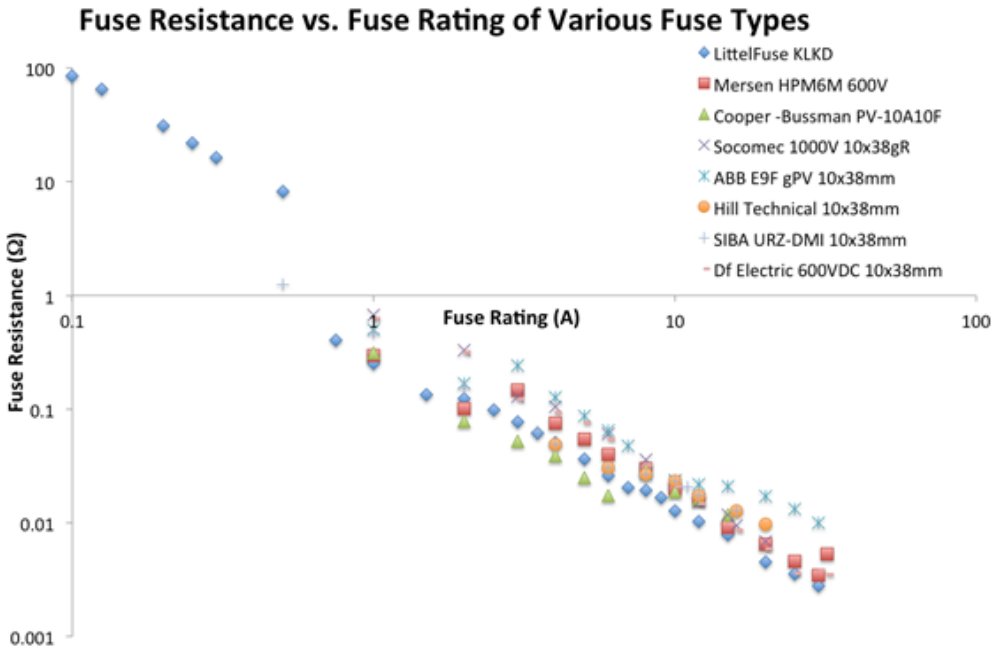

Figure 16. GFDI resistance vs. rating for a variety of 10x38 mm ("midget") fuses by various PV fuse manufacturers. Note that Ω = ohm, A = amperes, and V = volts.

Theoretical results indicate that the decreased GFDI trip point is more than offset by the increase in GFDI resistances. Figure 16 shows a graph of GFDI current vs. array size for GFDI ratings of 0.5A (8.16 ohms), 1A (0.252 ohm), 2A (0.124 ohm), and 5A (0.0363 ohm) and fault resistances of 0.1 and 1 ohm for both theoretical calculations (dashed lines) and SPICE simulations (points). Only the 1A (red) and 2A (purple) GFDIs are able to detect the blind spot (denoted by the grey triangles) for a 0.1 ohm fault due to a balance between GFDI rating and resistance. The 5A GFDI (orange) has a low resistance, but the trip point is high. The 0.5A GFDI (blue) has a low trip point, but the resistance is too high and prevents sufficient fault current flow through the GFDI to trip it. The Sandia modeling results suggest that, to decrease the ground fault blind spot, the optimal value for a fuse-based GFDI would be maximum 1A fuse for all array sizes.

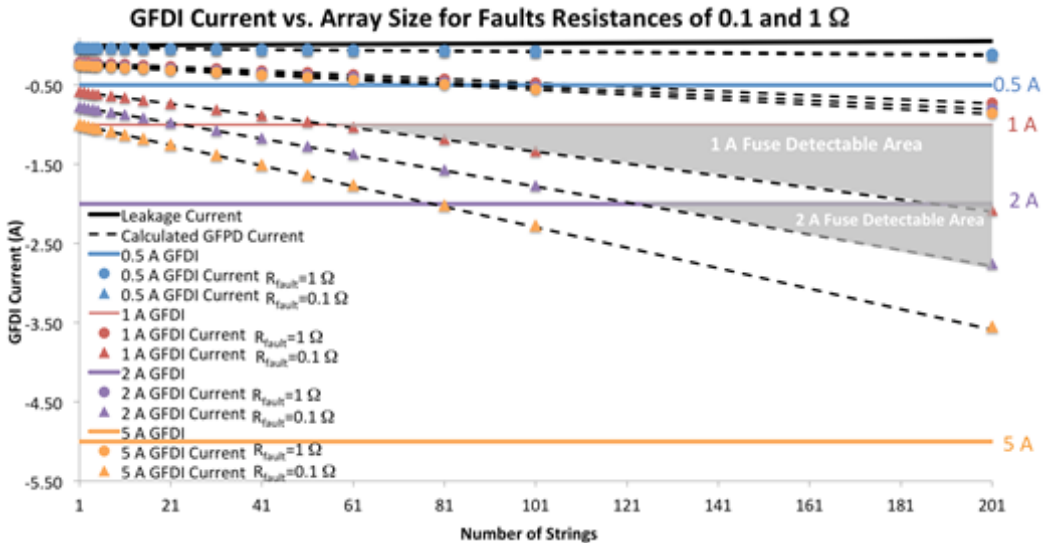

Figure 17. Graph of GFDI current vs. array size for various GFDI and fault resistances. Note that the color of the line indicates GFDI resistance. Blue traces denote 0.5A (8.16 ohms), red traces denote 1A (0.252 ohm), purple traces denote 2A (0.124 ohm), and the orange traces denote 5A (0.0363 ohm). Only the 1A and 2A fuses have both a low enough sensitivity and resistance to trip due to the blind spot fault. The region where I_{GFDI} is larger than the trip point is gray.

The modeling presented here does not include effects from any other sources of current that may flow through the GFDI such as leakage from cables, AC noise, or radio frequency (RF) noise from the array. These sources are not well characterized, but are believed to have contributed to the original field ground circuit measurements that were the basis for the existing UL 1741 fuse rating limits. A thorough characterization of these sources will be an important step in determining the nuisance trip potential of reduced fuse ratings.

SECTION 4—MITIGATION METHODS AND EQUIPMENT

This section presents a list of mitigation methods and associated equipment that are available to PV system owners to reduce system susceptibility to the ground fault blind spot. Some choices are inexpensive while others can require thousands of dollars per inverter to implement. Pros and cons of each option are included in the matrix of mitigation methods (Table 6). The options in the matrix are shown in preferential order according to the authors' consensus understanding of effectiveness and value.

The authors of this report stress two important warnings that must be observed before any mitigation methods are attempted. The first is that only trained and qualified personnel should ever work on PV systems and inverters. Hazardous voltage and current can exist at any time in PV systems and untrained personnel must never be allowed to inspect, test, or modify any system components or wiring.

The second warning concerns mitigation methods involving inverters. Only items that are specifically detailed in the installation instructions of an inverter can be installed without first contacting the manufacturer. Modifications to any certified product may affect its certification and warranty. As there is no one single answer or solution to address this, it is always best to contact the inverter manufacturer before attempting any modifications to a certified product. Moreover, the manufacturer may be aware of the ground fault issue and may have already developed a retrofit option. In any case, no site owner should ever attempt to modify, update, or install any equipment inside an inverter without contacting the inverter manufacturer first and receiving approval. Consideration should be given to the impact on product warranty and safety certification before modifications are implemented. Modified equipment may be subjected to a field evaluation to determine compliance with product safety standards.

Table 6

Matrix of Blind Spot Mitigation Methods

Mitigation Method	Effect	Cost	Pros	Cons	Additional Notes
1. Install residual current detector (RCD) on positive and negative array wiring and connect to alarm	Major increase in the sensitivity and flexibility of ground fault detection	Moderate to High	Use of RCDs has already been shown to detect and prevent blind spot conditions Allows operator to decide if alarm requires immediate action and reduces impact of false trips	Requires rewiring of array conductors through current sense doughnuts and interfacing with some type of monitoring Does not interrupt the fault current May require installation of a new enclosure to access existing conductors	Alarm signals a fault; It takes no other action
2. Install residual current detector (RCD) on positive and negative array wiring and connect to inverter emergency stop input (if available) or shunt trip breaker	Major increase in the sensitivity and flexibility of ground fault detection	Moderate to High	Use of RCDs has already been shown to detect and prevent blind spot conditions Interrupts fault current for grounded conductor faults Could be used to shut down contact combiners (if used) to make array safe	Requires rewiring of array conductors through current sense doughnuts False trips could shut down inverter causing loss of system availability Wiring the RCD trip signal into the inverter may impact inverter certification	Inverter manufacturer must approve this modification if field wiring to emergency stop not accommodated in listing and instructions
3. Install electronic current sense relay in ground fault fuse circuit	Major increase in the sensitivity and flexibility of ground fault detection	Moderate	Relays can be programmed to trigger on current and duration levels	Requires rewiring of ground fault fuse circuit False trips could shut down inverter causing loss of system availability Wiring the RCD trip signal into the inverter may impact inverter certification	Inverter manufacturer must approve this modification
4. Install isolation monitor, implement periodic checks	Capable of detecting low insulation conditions and ground faults	High	Prevents inverter start up until faults are corrected	Coordination with inverter logic needed to implement ground bond disconnect prior to test	Due to complexities with this process, inverter manufacturers have been reluctant to retrofit this function into existing systems
5. Reduce the ground fault fuse size	Minor increase in the sensitivity of ground fault detection	Low	Easy, inexpensive retrofit	Not as sensitive as electronic ground current monitoring May conflict with other inverter functionality May impact inverter certification	Contact the inverter manufacturer to confirm if or what lower current values of fuse can be used with a specific inverter
6. Annual operations and maintenance practices (including string and megger testing)	Capable of identifying blind spot faults	Moderate (but recurring)	Annual operation and maintenance (O&M) inspections are necessary for many reasons beyond the blind spot O&M can find undetected faults and degraded insulation	Requires routine visit by technicians to perform tests Faults that occur between inspections may still go undetected	IEC 62109, the UL 1741 CRD for non-isolated arrays, and the UL 1741 CRD for isolated ungrounded inverters all require that these inverters perform an array isolation check prior to operation; this is done before the inverter exports power and at least one time per day
7. Implement arc-fault current interruption (AFCI)	AFCI installed in array or string combiner boxes can isolate circuits when arc is detected	High (expected)	Isolating strings when arc is detected may lessen fault severity	AFCI may not be able to detect blind spot faults and series AFCIs are not evaluated for response to arcing faults to ground	Implementation is increasing slowly because of the limited commercial availability of AFCI products

Mitigation Method 1—Install Residual Current Detector (RCD) on Positive and Negative Array Wiring and Connect to Alarm

Differential current sensors, also known as residual current detectors or RCDs, are a commonly installed piece of equipment used to retrofit existing inverters and systems. RCDs used for this purpose need to be rated for use with AC and DC currents, and they need to be rated or set to an appropriate trip current level. A common way to deploy RCDs is to place the sensing transducer around both positive and negative conductors entering the inverter. Transducer sizes are available for monitoring cables as small as two 10 AWG conductors up to four 500 kcmil conductors. Multiple transducers can also be used on larger systems. Although the highest resolution of differential current is possible when individual sensors monitor single subarray conductor pairs, multiple circuits from the array can be bundled and run through a single current transducer of the RCD. Cost and desired sensitivity must be considered to determine the monitoring solution for a given system.

The setting of an RCD requires an understanding of typical ground current under normal conditions. Because many plant owners and operators are concerned about system operation and availability, one option is to respond to a detected fault by triggering an alarm rather than stopping the inverter. By using an alarm, a low threshold can be chosen for the RCD ground fault detection without incurring lost production from false detections. When the alarm is set, the output of the RCD can be monitored to see if the reading was a legitimate fault or if there was a false alarm. When a plant is getting false alarms, the alarm threshold can be raised to reduce this.

Based on study of the storm data from North Carolina, sufficiently long data averaging should be employed to disregard storm-related, transient currents while still capturing persistent ground fault currents. Most important, the baseline ground current of the system needs to be assessed and used for establishing the appropriate trip setting for this method. The baseline data presented in this paper illustrates that normal ground current values are system dependent and can vary with the inverter type and climate.

Mitigation Method 2—Install Residual Current Detector (RCD) on Positive and Negative Array Wiring and Connect to Emergency Stop of Inverter

A variation of the previous mitigation method is to wire the trigger of the RCD into the emergency stop function of an inverter. This method creates concern about false trips by the RCD, because it directly controls inverter shutdown. With each inverter trip, field technicians must be dispatched to confirm whether there is a fault, to repair the fault if it exists, and to return the system to operation. This method requires a good understanding of normally occurring ground currents so that the trip current setting of the RCD can be sufficiently high to prevent false alarms. As was discussed in the section on lightning effects, one method to prevent short-term transient current effects on an RCD is to set the RCD to average readings over 10 seconds before initiating a shutdown. For an RCD that has this averaging feature, short-term transients can be effectively differentiated from longer-term ground faults.

Mitigation Method 3—Electronic Current Sensing Relay

As noted above, it is not necessary to measure differential current in the array conductors in order to achieve increased ground current detection sensitivity. An electronic current sensor-controlled relay can be installed in the circuit between earth ground and the grounded conductor (in series with the ground fault fuse). This method is feasible for larger inverters, which often use a separate wire to perform this ground bonding function. (Smaller inverters, on the other hand, make these connections through circuit boards and cannot be monitored in this way.) Such devices are available with detection sensitivities down to 5 mA and with programmable delay settings. This method requires the sensor output to control a relay connected to the inverter's emergency stop input or a shunt trip relay in the system. As with all inverter modifications or upgrades mentioned in this report, the inverter manufacturer must be consulted prior to implementing this mitigation solution as it may affect the inverter or its certification.

Similar to methods 1 and 2, the trip setting for this method needs to be informed by the baseline ground currents observed with the system. It is also beneficial to have the ground current values logged in a data acquisition system

Mitigation Method 4—Isolation Monitor and Periodic Check

An isolation monitor is a device that measures the resistance of a circuit to earth. Incorporating and using an isolation monitor with ungrounded, isolated PV arrays is becoming a common safety practice. In the United States, where most PV systems have a ground bond connection on either the positive or negative conductor, this practice is more difficult. The connection to earth is often made through an OCP device used to sense ground current and limit this current by isolating circuits that exceed specified ground current limits. To use an isolation monitor in a grounded system like those prevalent in the United States, the grounding connection must be opened before the isolation monitor can take the PV array isolation reading. After this, if the array isolation resistance measurement exceeds a minimum acceptable threshold (indicating no fault has been detected), the array is allowed to reconnect the ground bond and the inverter can start AC power export.

The ground bond disconnect function, array isolation test, and array ground bond reconnect process requires coordination with inverter logic for a DC-grounded inverter. Due to complexities with this implementation and concerns about possible certification impact, some inverter manufacturers have been reluctant to retrofit this function into existing systems.

For future grounded system designs, one option recommended by Solar ABCs is that inverters employ an isolation check before operation as specified in IEC 62109 and UL 1741 CRDs. The existing standard (IEC 62109) for non-isolated arrays requires that an array isolation check be made prior to operation of PV arrays. During inverter operation, residual current detection is required. The combined effect of these two requirements substantially reduces the probability of two ground faults existing simultaneously in the array.

IEC 62109-2 is currently being revised to address this issue and prevent duplication and/or continuation of this blind spot susceptibility. It is expected that IEC 62109-2 will be revised to either require grounded isolated inverters to perform a PV array isolation measurement prior to AC power export (similar to non-isolated inverters) or to perform some other function consistent with mitigation methods 1, 2, or 3. Several Solar ABCs members participate in groups that maintain both UL 1741 as well as the IEC 62109-1 and -2 standards, and are working to address these ground fault monitoring and response concerns in upcoming revisions to these standards.

Mitigation Method 5—Reduce the Size of the Ground Fault Fuse

A simple and inexpensive solution to improving fault detection is to reduce the fuse current rating on ground fault protection devices that use a fuse in their detection scheme. Fuses can cost as little as a few dollars up to $150, but do not require any field rewiring to implement. Such fuses must be rated for DC circuit interruption. Fuses rated for AC voltage only will not be sufficient.

Modeling by Sandia (presented in Section 3) shows that reducing the ground fault fuse size for large inverters from 5A to 1A provides a marked increase in the sensitivity of the circuit to detect blind spot faults. However, while reducing fuse size from 5A to 1A can provide up to five times better blind spot protection, this is still roughly ten times less sensitive than the electronic fault current sensing methods discussed in Mitigation Methods 1-3

The inverter manufacturer must approve the replacement of a 5A fuse with a smaller one. This approval can either be in the form of a statement included in the manufacturer's documentation (allowing for a range of fuse sizes), or a letter from the manufacturer stating that a smaller fuse of the same voltage rating is permitted. As stated earlier, the modeling conducted to date does not attempt to address effects from other sources of current that may flow through the GFDI, such as leakage from cables, AC side noise, or RF noise from the array. The potential remains that, for some inverters, reducing fuse size may result in unanticipated nuisance trips.

Mitigation Method 6—Regular Operations and Maintenance

The methods above focused on various options for directly detecting or mitigating blind spot faults. This section discusses indirect measures that can improve system safety and reduce the potential for fires resulting from blind spots or other faults.

It is difficult to understate the importance of regular operations and maintenance (O&M) of a PV system when it comes to enhancing safety. Even if advanced detection and mitigation techniques are not implemented by system owners, O&M measures are the best way of identifying wiring problems early before they evolve into dangerous situations. Visual inspection of a PV array and its associated wiring is the first step in identifying potential failures like those that result from sharp edges in contact with conductors or stresses created by thermal expansion and contraction of conduit and conductors on rooftops. Preventive maintenance procedures that require annual inspections for these types of problems can effectively prevent many wear conditions in field wiring from degrading into ground faults.

When a system is first installed, best practice dictates that insulation testing (megger testing) be carried out on all DC and AC conductors prior to energizing the system. This is a simple test using a handheld device that imposes a short-term voltage on an open circuit and measures its resistance to ground. When all cable insulation is intact, a very high resistance reading is recorded (high megaohms to gigaohms). However, partial or complete cable insulation failure results in increased current to ground through the failure point and the megger resistance reading is lowered. "Low" for 600 V and 1,000 V cables without PV modules in the circuit is typically anything below 100 megaohms, according to the National Electrical Testing Association. As such, this is a good method for finding high-resistance ground faults that would not be detected by an inverter's existing ground fault protection.

Megger testing effectiveness in non-shielded cables is limited and will only detect faults with a conduction path. Also, if a damaged cable is dry with an air gap separating it from grounded metal, megger testing will not detect the insulation damage. It is recommended that a conductive medium (e.g., surfactant solution) be introduced prior to megger testing to improve its detection capabilities. Introducing a conductive medium can be challenging for some arrays, but experience has shown that it provides a marked increase in the ability to find intermittent faults.

Given the limitations of insulation testing, it is important to caution system owners and operators that annual testing is not sufficient to mitigate the blind spot issue. Field experience shows that insulation testing can and does find certain ground faults not identified by existing inverter GFDIs. Also, newer insulation testing devices with lower voltage settings (e.g., 50 V) can be used to find leaking surge arrestors, which is a common cause of power loss in aging PV systems.

Another important annual O&M procedure is string voltage and current testing. This standard test is usually performed at commissioning to ensure that each PV module string is producing proper voltage and current relative to other strings. Open circuit voltage is tested with the inverter off by isolating each string. String current can either be tested short-circuit, or the maximum operating current can be measured with the inverter operating. Series measurements of current using the current setting of a multi-meter can be used and are generally more accurate, but small current clamps with low-current ratings can also be used.

String open circuit voltage measurements lower than normal can be indicative of ground faults in ungrounded conductors, failed bypass diodes, or shorted cells. Low current measurements can be an indication of soiled modules, blown fuses, or poor (high-resistance) electrical connections. The latter, if left to persist and worsen, can result in overheating and burning at the failing connection. Any abnormal measurement should be followed up with closer inspection of the modules and connections in the affected string.

Other routine O&M steps that can help reduce the incidence or impact of blind spot ground faults include:

- visual and manual inspection of combiner box interiors, looking for signs of water or debris buildup; heat damage on insulation; staining of connectors, baseplates, and enclosures; and loosened string conductor connections;
- visual and manual inspection of the string wiring, looking for pinch-points, sections tightly pulled against racking or wireway equipment, or buildup of debris around the wiring;
- checking the torque on field connections in string and array combiner boxes to verify proper connections;
- inspection of modules for discoloration from overheating or burn marks;
- thermal imaging of module and, if accessible, the intermodule wiring (this can be particularly effective at catching weakened, high resistance connections between pigtail connectors or at the junction box); and
- thermal imaging of field and manufacturer terminations in combiners and inverter while operating to identify any high operating temperatures resulting from poor connections.

Solar ABCs will be publishing a full report on O&M recommendations later in 2013.

Mitigation Method 7—Use of Arc-Fault Detection

DC arc-fault detection is a protection measure on its way to becoming a standard feature in PV systems. Series DC arc-fault protection (arc-fault current interruption or AFCI) was introduced as a requirement in the 2011 NEC for rooftop systems and will be required for all systems (with limited exceptions) in the 2014 version. At this time, there is at least one inverter manufacturer selling products with AFCI functionality listed, five standalone PV AFCI devices listed for compliance with UL Outline 1699B, and more are on the way. Although PV AFCI product availability and installations are increasing, there are still relatively few products commercially available. At this time, there is at least one inverter manufacturer selling products with AFCI functionality listed, five standalone PV AFCI devices listed for compliance with UL Outline 1699B, and more are on the way.

The PV AVCI standalone devices can be located at various points throughout the array and they can be added to the designs of PV combiner boxes. Series AFCI addresses series-arcs or arcing current that is flowing in the normal current path of the PV circuit. For example, a poor pigtail connection between modules can worsen to the point where there is no longer physical contact between the connectors but current arcs across the air gap. This type of fault is neither a ground fault nor a line-to-line fault and therefore is not detected by any of the ground fault measures discussed in this report. (Arcs that occur to ground or line-to-line are called parallel arcs.) Apart from ground faults, series arcs are probably the next largest cause of fires in PV systems in the United States, which is why codes and standards have moved towards AFCI requirements.

Systems incorporating combiner box level AFCI are not protected against blind spot ground faults but they may reduce the impact of the second fault and possibly even prevent fire. Combiner box AFCI could possibly have minimized the impact of the Bakersfield fire, for example. In that system, a blind spot fault occurred on a grounded string conductor in the array that went undetected. The subsequent ungrounded conductor fault occurred on a large feeder circuit cable, shorting and arcing to a conduit. Fault current flowed from each array combiner box to the conduit fault to ground, through the ground circuit, and back through the faulted grounded conductor circuit to the modules.

Figure 18 shows a system schematic depicting this scenario. If series AFCI with automatic disconnecting capability had been present in each of the combiner boxes, they should have all detected the arcing in what had become a closed series circuit through the ground path. With the inverter faulted offline and ground fault interrupt fuse blown, there is no parallel path outside of the fault loop. As such, if all combiner box circuits opened on AFCI detection, there would be no more source of current to the ungrounded conductor fault, and arcing would have ceased.

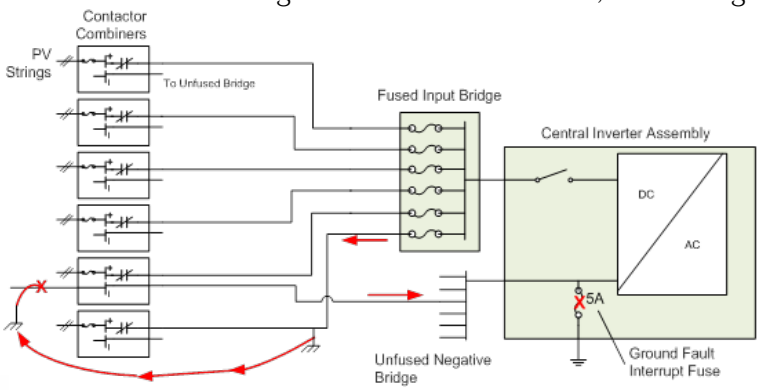

Figure 18. Example of blind spot fault scenario mitigated by combiner box level arc-fault protection.

This illustrates an example in which AFCI contactors are in the current path of the fault. If the ground current loop is outside the AFCI path, the interruption is not effective. This is the case, for example, if the grounded conductor and ungrounded conductor fault both occur on strings connected to the same combiner box. Fault current would continue to circulate in the strings even if the combiner box contactor opens.

SECTION 5—OVERVIEW OF CHANGES COMING TO CODES AND STANDARDS IMPACTING GROUND FAULT PROTECTION

What follows are brief discussions of ongoing revisions to the major codes and standards affecting PV inverters and PV ground fault protection products.

The **2014 *NEC*** process is near completion. Several items were introduced during this code cycle to address issues related to the ground fault blind spot. Of particular interest are the changes in 690.5, 690.35, and 690.41. The new requirements for PV GFDI eliminate the improper reference for ground fault protection to respond to ground fault current. They also require that a ground fault protection system be capable of detecting a ground fault throughout the PV array, system components, and DC current-carrying conductors, including any intentionally grounded conductors. It is also required a ground fault protection system to be specifically listed for providing PV ground fault protection. The system grounding section has been reorganized to clarify the various types of system grounding arrangements that exist in PV system designs. Each different type of system requires different approaches for detecting ground faults and preventing the damaging effects of ground faults.

IEC 62109-1 is the international equivalent of UL 1741, and covers the general requirements for PV power conversion and electronic equipment. IEC 62109-2 is a secondary document that addresses PV inverter specific requirements and is to be used in conjunction with IEC 62109-1. IEC 62109-2 includes the ground fault protection requirements for PV circuits. These standards are being adopted internationally for PV inverters, converters, and other PV electronic equipment. Based in part on the preliminary findings of Solar ABCs ground fault investigations, the ground fault protection requirements in IEC 62109-2 are being revised.

At the last UL 1741 Standards Technical Panel (STP) meeting, the STP agreed to develop and adopt a **United States-based version of IEC 62109.** A UL 62109 International Harmonization Committee was established and tasked with developing the U.S. national difference intended to address critical issues related to United States-specific installation codes as well as U.S. equipment and component standards. UL 62109-1 was sent out for comment, and UL is addressing the STP comments they received in preparation for the upcoming ballot draft, which will be sent out in the summer of 2013. The UL 62109-2 draft will incorporate the U.S. national differences that include revised requirements for additional protection of grounded isolated applications to address this blind spot condition—for example, regular array isolation measurements.

The previously mentioned CRDs provide methodologies for manufacturers to build and certify PV inverter products that include PV array isolation measurement methodologies, more sensitive ground fault detection schemes, and faster clearing/response times to ground faults. As the STP intent is to adopt UL 62109 to replace UL 1741 for PV product safety certifications, the new/updated ground fault protection requirements will be in UL 62109-2. If there are delays in the adoption of the UL 62109-2, a proposal to revise UL 1741 may be needed to incorporate the new/updated ground fault protection requirements.

Section 6—Conclusions

PV system owners must weigh the costs and benefits of any additional protection. Ultimately, the decision to employ any safety measure is a function of the potential consequences of doing nothing. Although losses from fires caused by PV systems have been historically quite low relative to the number of systems in the field, this field experience is not necessarily indicative of future losses. As systems age, ground faults and arc-faults can be expected to increase in number and potentially in consequences. Equipped with the knowledge in this report, PV system owners, designers, and installers will be able to more effectively make correct decisions about what measures to employ and when those measures are cost-effective.

ACRONYMS

AC	alternating current
AFCI	arc-fault current interruption
AWG	American wire gauge
DC	direct current
DETL	Distributed Energy Technologies Laboratory
DOE	U.S. Department of Energy
EGC	equipment grounding conductor
GFA	ground fault appliance
GFDI	ground fault detector/interrupter
IEC	International Electrotechnical Commission
kcmil	thousand circular mils
kohm	kilo-ohm
kVA	kilovolt-amps
kW	kilowatt
mA	milliamp
mV	millivolt
NEC	*National Electrical Code®*
OCP	overcurrent protection
PV	photovoltaic
RCD	residual current detector
RF	radio frequency
SCE	Southern California Edison
Solar ABCs	Solar America Board for Codes and Standards
SPICE	simulation program with integrated circuit emphasis
STP	Standards Technical Panel
UL	Underwriters Laboratories
V	volt

Solar America Board for Codes and Standards

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Analysis of Fuses for "Blind Spot" Ground Fault Detection in Photovoltaic Power Systems

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June 2013

Solar America Board for Codes and Standards
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EXECUTIVE SUMMARY

A 2012 Solar America Board for Codes and Standards (Solar ABCs) publication, *The Ground-Fault Protection Blind Spot: Safety Concern for Larger PV Systems in the U.S.* (Brooks, 2012), revealed that undetected faults on grounded PV array conductors were an initial step in a sequence leading to two well-publicized rooftop fires. In that paper, the theoretical detection limits of traditional ground fault protection systems were discussed but not explored in depth.

To further the analysis of ground fault protection in photovoltaic (PV) systems, scientists from Sandia National Laboratories developed a functional circuit model of the PV system including modules, wiring, switchgear, grounded or ungrounded components, and the inverter. This model was implemented using the Simulation Program with Integrated Circuit Emphasis (SPICE) modeling language. The Sandia Technical Report, *Photovoltaic Ground Fault and Blind Spot Electrical Stimulations* (Flicker & Johnson, 2013), presents the complete derivation of the Sandia PV System SPICE model and the results of parametric fault current studies with varying array topologies, fuse sizes, and fault impedances.

This Solar ABCs report contains the subsection of the Sandia technical report that focuses on blind spot ground faults to the grounded current-carrying conductor. The behavior of the array during these faults is studied for a range of ground fault fuse sizes to determine if reducing the size of the fuse improves ground fault detection sensitivity. Results of simulation studies show that reducing the amperage rating of the protective fuse does increase fault current detection sensitivity without increasing the likelihood of nuisance trips. However, this effect reaches a limit as fuses become smaller and their internal resistance increases to the point of becoming a major element in the fault current circuit.

TABLE OF CONTENTS

DISCLAIMER 2

EXECUTIVE SUMMARY 3

AUTHOR BIOGRAPHIES 5

SOLAR AMERICA BOARD FOR CODES AND STANDARDS 5

ACKNOWLEDGMENT 5

INTRODUCTION 6

ANALYTICAL ANALYSIS OF GROUND FAULT DETECTION LIMITS 7

- Effects of Parasitic Cable and Fuse Impedances in PV Arrays 7
- Leakage Currents 8
- Detection of Blind Spot Fault With GFPDs 10

NUMERICAL SIMULATIONS OF BLIND SPOT FAULTS 15

- PV Array Simulation Setup 15
- Simulation Results 16
- GFPD Current During High-Impedance Blind Spot Ground Faults 18
- Parametric Study of GFPD Current 21

SUMMARY AND CONCLUSIONS 26

ACRONYMS 27

REFERENCES 28

AUTHOR BIOGRAPHIES

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Solar America Board for Codes and Standards

The Solar America Board for Codes and Standards (Solar ABCs) provides an effective venue for all solar stakeholders. A collaboration of experts formally gathers and prioritizes input from groups such as policy makers, manufacturers, installers, and large- and small-scale consumers to make balanced recommendations to codes and standards organizations for existing and new solar technologies. The U.S. Department of Energy funds Solar ABCs as part of its commitment to facilitate widespread adoption of safe, reliable, and cost-effective solar technologies.

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Acknowledgment

This material is based upon work supported by the U.S. Department of Energy under Award Number DE-FC36-07GO17034. This work was funded by the DOE Office of Energy Efficiency and Renewable Energy. Sandia National Laboratories is a multi-program laboratory managed and operated by Sandia Corporation, a wholly owned subsidiary of Lockheed Martin Corporation, for the U.S. Department of Energy's National Nuclear Security Administration under contract DE-AC04-94AL85000.

Introduction

A PV array ground fault is an electrical short circuit between one or more of the array's conductors and earth ground. Such faults are usually the result of mechanical, electrical, or chemical degradation of photovoltaic (PV) components or mistakes made during installation. In order to protect the array against continued operation during a ground fault event, a ground fault protection device (GFPD) or ground fault detector/interrupter (GFDI) is used to detect ground fault currents (Wiles, 2012).

Recently, a detection limit, or "blind spot," in traditional ground fault protection systems has been identified for the direct current- (DC-) grounded, alternating current- (AC-) isolated PV systems, most common in the United States (Wiles, 2012). This blind spot occurs when the grounded current-carrying conductor (CCC) is faulted to the equipment grounding conductor (EGC) as shown in *Figure 1*.

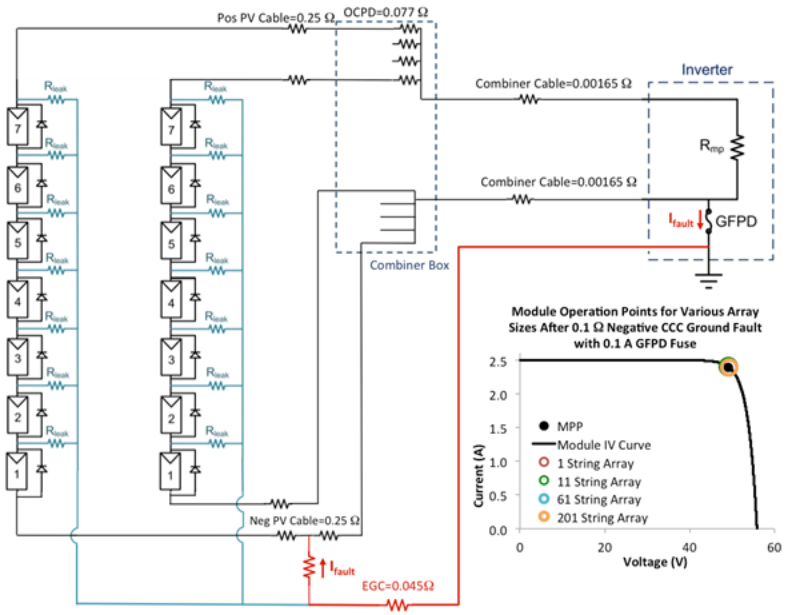


Figure 1. Schematic for an array with parasitic impedances measured from a fielded system and non-zero GFPD impedance. The teal line denotes the leakage current path. The path of the ground fault on the negative CCC is denoted in red.

These faults may produce small fault currents that can go undetected by GFPDs. The danger of undetected ground faults in the EGC is twofold:

1. an energized EGC can be a shock hazard, resulting in severe injury; and
2. if there is a second ground fault in parallel, the array can be shorted though the EGC, bypassing the GFPD and allowing fault current to flow through the system undetected and with no means of interruption.

The fires presented in (Brooks, 2011) and (Brooks, 2012) have highlighted the incomplete protection provided by ground fault fuses in grounded arrays in the United States. Field experiments have confirmed the existence of the ground fault blind spot in grounded systems (Ball et al., 2013 [in press]). However in ungrounded, non-isolated, and hybrid systems the ground fault blind spot does not exist.

In this study, we develop an analytical and numerical Simulation Program with Integrated Circuit Emphasis (SPICE) model for PV systems that have a ground fault between the grounded CCC to the EGC. These models are used to perform electrical simulations of faults occurring on arrays of various sizes (representing residential, commercial, and utility scale systems) with different fault, cabling, and GFPD impedances.

ANALYTICAL ANALYSIS OF GROUND FAULT DETECTION LIMITS

Circuit analyses were performed to determine the magnitude of fault currents that can remain undetected in several generic array topologies. As will be shown in Numerical Simulations of Blind Spot Faults, the analytical solutions are valid only if the modules remain close to their maximum power point (MPP) during the fault, such as in the 0.1 ohm (Ω) fault in *Figure 1*. If there is a significant change in the operating point of the modules, the expressions for fault current become less accurate. However, for the majority of PV configurations, the analytical expressions derived in this section will closely predict fault currents and are provided to (a) allow independent analysis of blind spot vulnerabilities in specific PV systems, (b) show trends in different array parameters, and (c) provide a more thorough understanding of fault detection and the blind spot problem.

Effects of Parasitic Cable and Fuse Impedances in PV Arrays

To model current flow during a ground fault, the internal resistances of the conductors and the GFPD must be included because the current division between the fault path and the intended conduction path is heavily dependent on small internal resistances. In the ideal case, fuse ratings could be decreased freely without affecting the GFPD current. However, in reality, fuse impedance changes with fuse ampere rating. *Figure 2* shows a graph of fuse resistance vs. fuse rating for a number of 10x38mm style fuses from a variety of manufacturers. UL 1741 (UL, 2001) mandates the maximum sizing of these protection devices based on the array size, as shown in *Figure 3*. The resistance of the fuse is inversely related to the fuse rating. Fuses with low trip ratings can have significant resistances. For example, the 0.1 ampere (A) Littelfuse KLKD fuse has a resistance of 85.5 **Ω.** Such large resistances have significant effects on the GFPD current and fuse resistance must be balanced with fuse trip point in order to maximize GFPD fault detection capabilities.

This GFPD impedance means that the grounded CCC (typically the negative conductor) is no longer at ground potential, but instead *functionally* grounded by the fuse. When a fuse with internal resistance is included in the model of a PV system, the conductor is at a voltage above ground potential, which introduces the possibility of ground faults from the grounded CCC through the EGC.

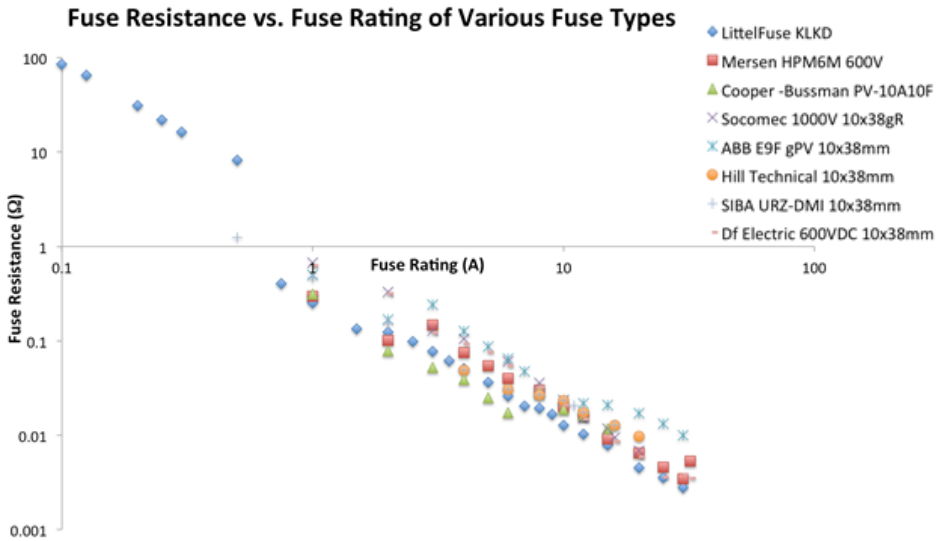
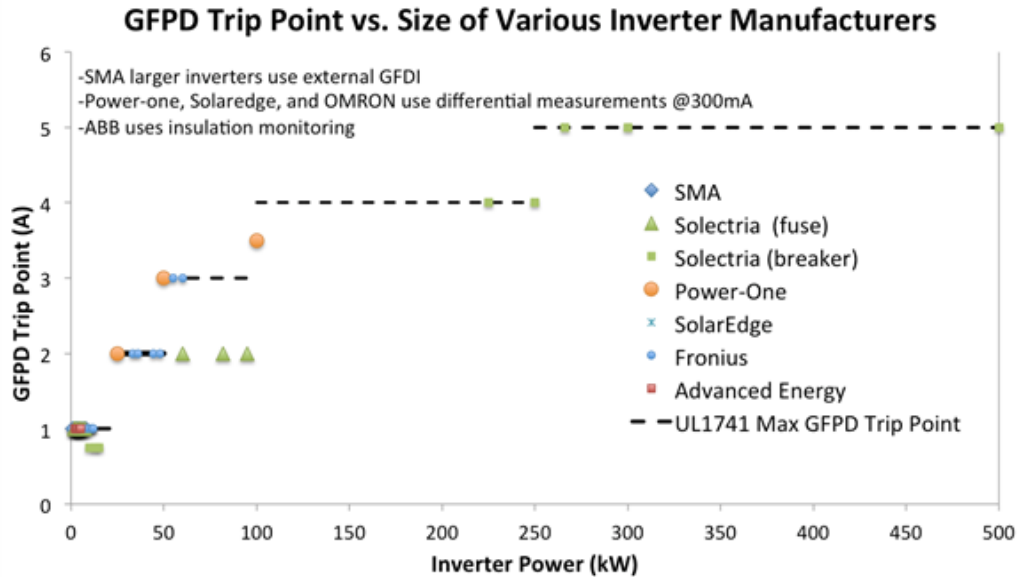


Figure 2. GFPD resistance vs. rating for a variety of 10x38 mm ("midget") fuses by various PV fuse manufacturers. In general, the more sensitive the fuse, the higher the intrinsic resistance (ABB Group, 2010; Cooper-Bussmann, 2009; DF Electric, 2012; Hill Technical Sales Group, 2012; Littelfuse. 2011; Mersen [formerly Ferraz Shawmut], 2010; SIBA Fuses, 2006; Socomec, 2011-2012).



Device DC Rating (kW)	Max. Ground-Fault Current Detecting Setting (A)
0-25	1
25-50	2
50-100	3
100-250	4
>250	5

Figure 3. (top) Plot of GFPD trip point vs. rated inverter power for a number of commercially available inverters. As the inverter power increases, the GFPD trip point also increases. (bottom) UL 1741 maximum allowable ground fault trip ranges are also displayed as a function of inverter DC power rating (UL, 2001).

Leakage Currents

Each module has a leakage current to ground controlled by a resistor (R_{leak}). For the purposes of simulation, R_{leak} was conservatively estimated to be 5 megaohm (MΩ), which would give a "nominal" leakage (as measured by the procedure presented in International Electrotechnical Commission [IEC] 61215) of 100 microampere (μA)/module at 500 volts (V) above ground. In the topology used in the simulation, the leakage current is approximately 275 μA/string. IEC 61215 mandates a minimum module-to-frame isolation of 40 MΩ·m^2). For the topology used in these simulations, a 1.5 m^2 module would have a maximum allowable IEC leakage of 18.75 μA/module (IEC, 2005). Therefore, the module leakage used here will likely over predict the leakage of a pristine array by ~430%, though leakage current has been shown to increase with both array age, electrical stress, and various environmental conditions (del Cueto & McMahon, 2002). Even with the increased module leakage, the total leakage for a 500 kW array would only be 0.14 A. So fuse sizes as low as 0.25 A could be used on large arrays without expected nuisance tripping from module leakage, as Figure 4 shows (Flicker & Johnson, 2013 [in press]).

The modeling in this work does not attempt to address other sources of current that may flow through the GFPD device, such as leakage from cables and inverter, noise from the AC side, or radio frequency noise within the array. These sources are not well characterized, but are generally believed to have contributed to field ground circuit measurements that were the basis for the original UL 1741 fuse rating limits. Further characterization of these sources is an important step in determining the nuisance trip potential of reduced fuse ratings.

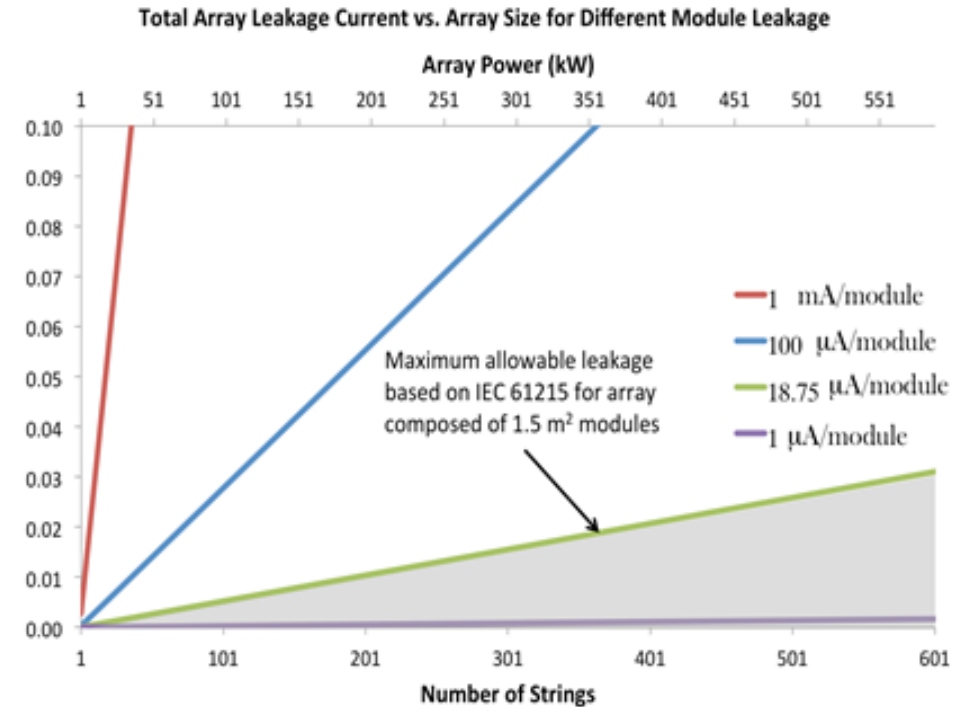


Figure 4. Total array leakage current vs. array size for a given leakage rate per module (measured at 500 V applied bias) ranging from 1 µA to 200 µA. Even for large arrays and module leakage well above the maximum mandated by IEC 61215, the total module leakage current is small, so 0.25 A fuses could be used without nuisance tripping.

It should be noted that the fault current is in the opposite direction of the leakage current, as shown in *Figure 5.* This indicates that in arrays with large leakage currents, it is more difficult for the GFPD to detect a blind spot ground fault because the fault current must first reverse the leakage current. Note that for these simulations, the current sign convention is current through the GFPD from EGC to negative CCC is positive.

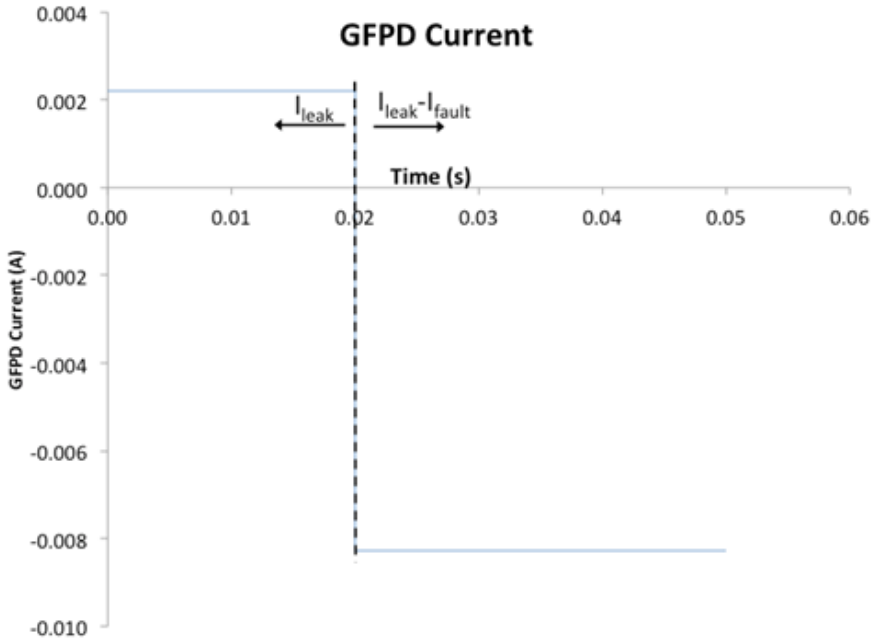


Figure 5. Graph of GFPD current vs. time for a SPICE simulation of a fault from the negative CCC to ground. The array is faulted at 0.02 seconds. Before the fault, leakage current flows from ground to the negative CCC through the GFPD. After the fault, current flows through the GFPD in the opposite direction.

Detection of Blind Spot Fault With GFPDs

Through circuit analysis, the GFPD current can be shown to be a function of the module maximum power current (I_{mp}), number of strings (C), wiring resistance (R_{comb}, R_{EGC}, etc), resistance of the faulted portion of the PV cabling (R_x), fault resistance (R_{fault}), GFPD resistance (R_{GFPD}), and the array leakage current (I_{leak}).

The circuit diagram in *Figure 6* shows the current paths for a single string that has a fault in the grounded negative CCC at some point in the PV cabling. The fault bisects the PV cable at some arbitrary point and acts as voltage divisor. R_x denotes the resistance of the PV cabling included in the fault loop, while R_y denotes the portion of PV cabling resistance that is not included in the fault loop. The sum of R_x and R_y is equal to R_{PV} and the ratio of the two resistances is equal to the percentage of PV cabling that is faulted.

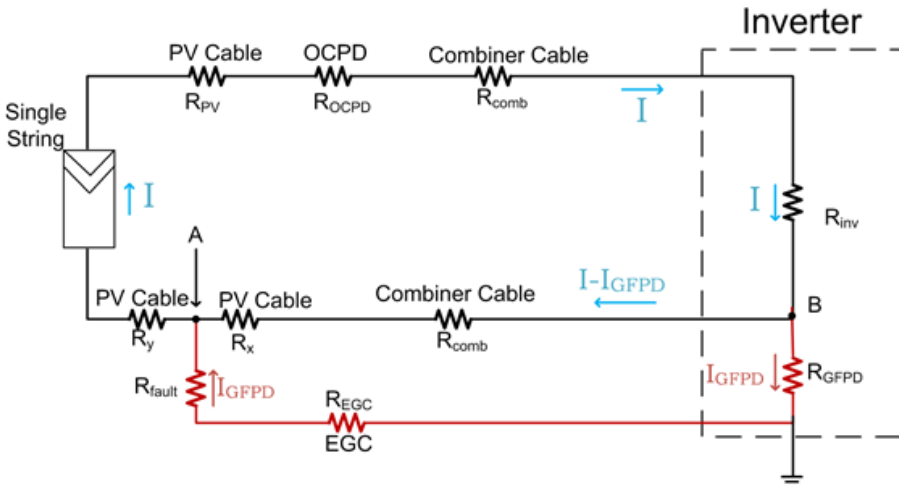


Figure 6. Circuit diagram of negative CCC fault with a single string at an arbitrary point in the negative PV cabling. The ratio of R_x and R_y indicates the percentage of PV cabling faulted. Resistances and currents used in Kirchoff's Voltage Law equations are shown.

The inset graph in *Figure 1* shows the module operating point for various array sizes after the fault. The location of the PV modules on their IV curve is nearly unchanged due to the blind spot fault, so the string current is treated as constant in the following analytical analysis. By Kirchoff's Current Law (KCL), current is conserved at circuit junctions. Also, by Kirchoff's Voltage Law (KVL), the sum of voltages in a closed loop is always equal to zero:

$$\sum_{k=1}^{n} V_k = 0 \tag{1}$$

This implies that the voltage drop between points A and B is equivalent regardless of the current path. By Ohm's Law, the voltage drop between A and B can be written as:

$$\Delta V_{A,B} = I_{GFPD} \cdot \left(R_{GFPD} + R_{EGC} + R_{fault}\right) = \left(I - I_{GFPD}\right) \cdot \left(R_{comb} + R_x\right) \tag{2}$$

By distributing and refactoring in terms of I and I_{GFPD} and solving for I_{GFPD}, Equation (2) can be written as:

$$I_{GFPD} = \frac{I \cdot \left(R_{comb} + R_x\right)}{R_{GFPD} + R_{EGC} + R_{comb} + R_x} \tag{3}$$

As shown in the simulations previously, the operating point of the modules on the IV curve are nearly unaltered during a negative CCC ground fault. Therefore:

$$I = I_{mp} \tag{4}$$

and,

$$I_{GFPD} = \frac{I_{mp} \cdot (R_{comb} + R_x)}{(R_{GFPD} + R_{EGC} + R_{fault} + R_{comb} + R_x)} \tag{5}$$

Next, consider the case of a negative CCC fault with multiple strings. *Figure 7* shows a circuit schematic for an array composed of multiple strings with a negative CCC fault at a single string. The module symbol on the left indicates a single string while the module symbol on the right is a stand-in for (C-1) parallel strings. This is a slightly more complicated problem because this fault diverts current away from the negative CCC path (I_1) through the unfaulted strings (I_2).

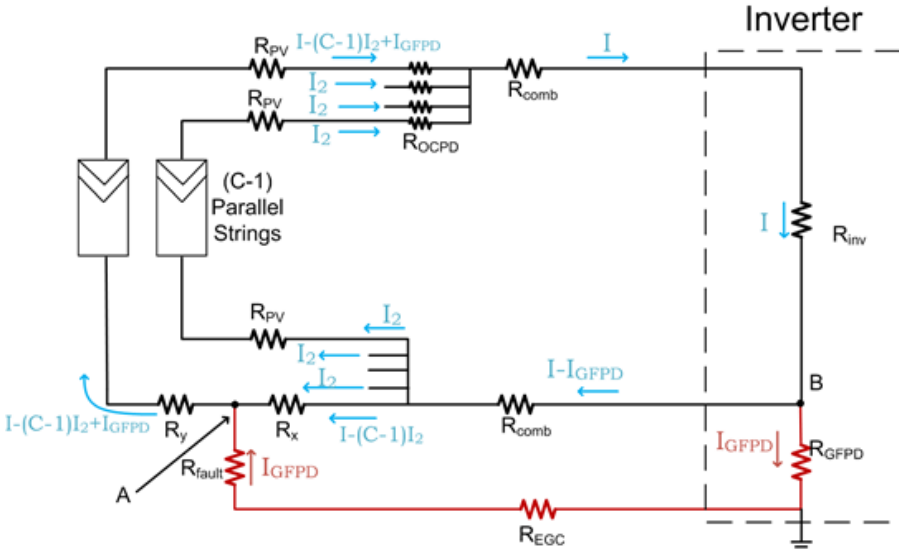


Figure 7. Circuit diagram of negative CCC fault of an array with a number (C) of parallel strings and a fault at some arbitrary point in the negative PV cabling. The ratio of R_x and R_y indicates the percentage of PV cabling faulted. Resistances and currents used in KVL equations are shown.

The results of KVL circuit analysis on this circuit are similar to Equation (3) and the GFPD current can be described by:

$$(I - I_{GFPD}) \cdot R_{comb} + I_1 \cdot R_x = I_{GFPD} \cdot (R_{GFPD} + R_{EGC} + R_{fault}) \tag{6}$$

As in the previous derivations, it is fortuitous that the module operating points do not change due to the negative CCC fault. Because of this, the current through the strings is the same before and after the fault and I, I_1, and I_2 can be described by:

$$I = C \cdot I_{mp} \tag{7}$$

$$I_1 + I_{GFPD} = I_{mp} \tag{8}$$

This allows Equation (6) to be rewritten as:

$$(C \cdot I_{mp} - I_{GFPD}) \cdot R_{comb} + (I_{mp} - I_{GFPD}) \cdot R_x = I_{GFPD} \cdot (R_{GFPD} + R_{EGC} + R_{fault}) \tag{9}$$

Finally, by regrouping terms and solving for I_{GFPD}, Equation (9) can be reduced to:

$$I_{GFPD} = \frac{I_{mp} \cdot (C \cdot R_{comb} + R_x)}{(R_{GFPD} + R_{EGC} + R_{comb} + R_x)} \tag{10}$$

The circuit schematic depicted in *Figure 7* is the type of circuit used in the simulations. However, it is usually only representative for ≤ 50 string arrays because larger arrays often contain recombiners, shown in *Figure 8*. Groups of strings are wired together into a combiner box and then recombined before being connected to the inverter.

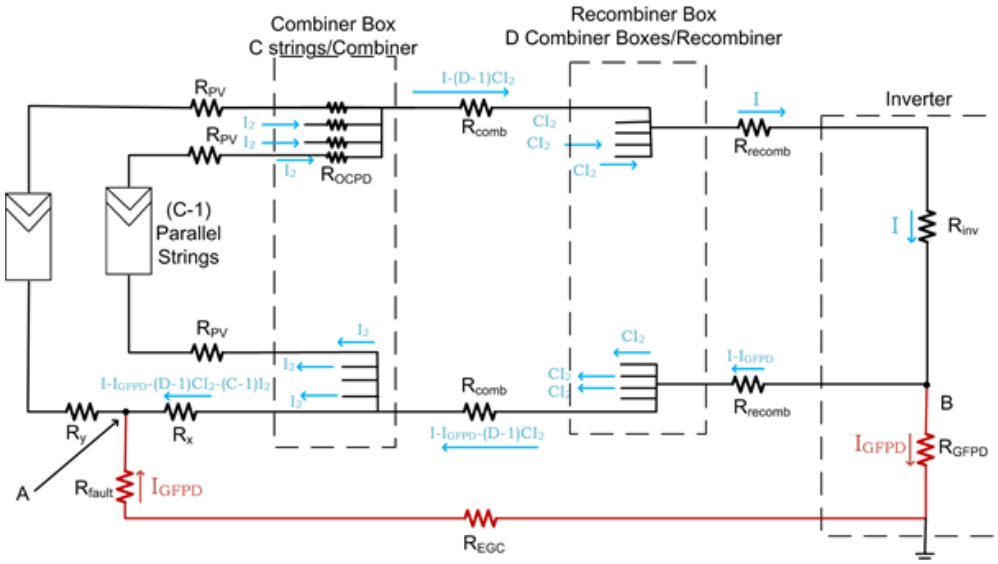


Figure 8. Circuit diagram of negative CCC fault of an array with a number (C) of multiple parallel strings, which are wired into a combiner box. D combiner boxes outputs are then wired into a recombiner box. A fault occurs at some arbitrary point in the negative PV cabling of a string. The ratio of R_x and R_y indicates the percentage of PV cabling faulted. Resistances and currents used in KVL equations are shown.

In this case, the KVL can be described by:

$$I_{GFPD} \cdot R_{GFPD} + I_{GFPD} \cdot R_{EGC} + I_{GFPD} \cdot R_{Fault} = \\ (I - I_{GFPD}) \cdot R_{recomb} + [I - I_{GFPD} - (D-1) \cdot C \cdot I_2] \cdot R_{comb} + [I - I_{GFPD} - (D-1) \cdot C \cdot I_2 - (C-1) \cdot I_2] \cdot R_x \quad (11)$$

This equation can be simplified because the strings remain at their maximum power by:

$$I = D \cdot C \cdot I_{mp} \\ I_2 = I_{mp} \quad (12)$$

So that Equation (11) can be simplified to:

$$I_{GFPD}(R_{GFPD} + R_{EGC} + R_{Fault}) = (D \cdot C \cdot I_{mp} - I_{GFPD}) \cdot R_{recomb} + [C \cdot I_{mp} - I_{GFPD}] \cdot R_{comb} + (I_{mp} - I_{GFPD}) \cdot R_x \quad (13)$$

Finally, the GFPD current can be found by simplifying and grouping to be:

$$I_{GFPD} = \frac{I_{mp}[D \cdot C \cdot R_{recomb} + C \cdot R_{comb} + R_x]}{R_{GFPD} + R_{EGC} + R_{Fault} + R_{recomb} + R_{comb} + R_x} \quad (14)$$

A simple check shows that if the number of combiner boxes per recombiner box is chosen as one or the recombiner resistance is set to zero, Equation (14) reduces to Equation (10).

For the more complicated array shown in *Figure 8,* there are three possible positions for a fault. The equation for a fault at some point in a string is shown in Equation (14). A fault at the combiner cable means that R_x becomes zero and R_{comb} is redefined as R_x and R_y to give a GFPD current of:

$$I_{GFPD} = \frac{I_{mp}\left(D \cdot C \cdot R_{recomb} + C \cdot R_x\right)}{R_{GFPD} + R_{EGC} + R_{fault} + R_{recomb} + R_x} \tag{15}$$

This equation is further simplified for the case of a fault at the recombiner cabling. In this case, R_x and R_{comb} are both zero in Equation (14) and R_{recomb} is redefined as R_x and R_y to give a GFPD current equivalent to:

$$I_{GFPD} = \frac{D \cdot C \cdot I_{mp} \cdot R_x}{R_{GFPD} + R_{EGC} + R_{fault} + R_x} \tag{16}$$

The previous circuit analyses have all been carried out for perfect arrays. However, PV arrays have leakage currents. In the case of ground faults at the negative CCC, the leakage current flows in the opposition direction of the fault current (see, for example, *Figure 9*).

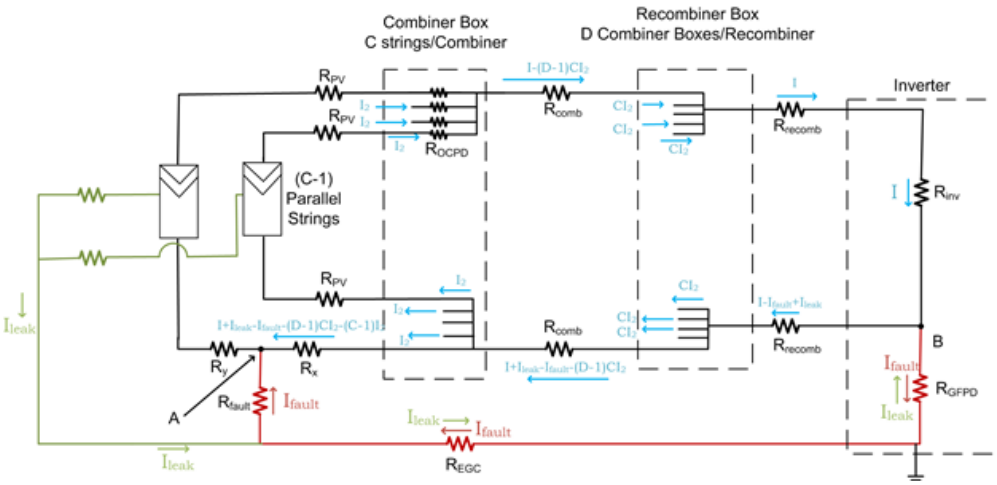


Figure 9. Circuit diagram of negative CCC fault of an array with leakage current. Resistances and currents used in KVL equations are shown.equations are shown.

The KVL analysis of the circuit between points A and B can be described by:

$$\begin{aligned}&\left(I + I_{leak} - I_{fault}\right) \cdot R_{recomb} + \left(I + I_{leak} - I_{fault} - (D-1)CI_2\right) \cdot R_{comb} + \left(I + I_{leak} - I_{fault} - (D-1) \cdot C \cdot I_2 - (C-1) \cdot I_2\right) \cdot R_x \\ &= \left(I_{fault} - I_{leak}\right) \cdot R_{GFPD} + \left(I_{fault} - I_{leak}\right) \cdot R_{EGC} + I_{fault} \cdot R_{fault}\end{aligned} \tag{17}$$

Again, the modules are at maximum power so they can be described by:

$$\begin{aligned}I &= D \cdot C \cdot I_{mp} \\ I_2 &= I_{mp}\end{aligned} \tag{18}$$

So Equation (18) can be inserted into Equation (17):

$$\left(D\cdot C\cdot I_{mp}+I_{leak}-I_{fault}\right)\cdot R_{recomb}+\left(D\cdot C\cdot I_{mp}+I_{leak}-I_{fault}-D\cdot C\cdot I_{mp}+C\cdot I_{mp}\right)\cdot R_{comb}+\left(I_{mp}-I_{fault}+I_{leak}\right)\cdot R_{x}$$
$$=I_{fault}\cdot\left(R_{GFPD}+R_{EGC}+R_{fault}\right)-I_{leak}\cdot\left(R_{GFPD}+R_{EGC}\right) \quad (19)$$

And solving for I_{fault}:

$$I_{fault}=\frac{I_{mp}\cdot\left(D\cdot C\cdot R_{recomb}+C\cdot R_{comb}+R_{x}\right)+I_{leak}\cdot\left(R_{recomb}+R_{comb}+R_{x}+R_{GFPD}+R_{EGC}\right)}{\left(R_{GFPD}+R_{EGC}+R_{fault}+R_{recomb}+R_{comb}+R_{x}\right)} \quad (20)$$

The GFPD current is the difference in the fault and leakage currents (and, by convention in these simulations, I_{fault} is taken to be negative), so I_{fault} can be transformed into I_{GFPD} by:

$$I_{GFPD}=I_{leak}-I_{fault} \quad (21)$$

Finally, Equation (20) can be solved in terms of I_{GFPD} by substituting Equation (21) into Equation (20):

$$I_{fault}=I_{leak}-\frac{I_{mp}\cdot\left(D\cdot C\cdot R_{recomb}+C\cdot R_{comb}+R_{x}\right)+I_{leak}\cdot\left(R_{recomb}+R_{comb}+R_{x}+R_{GFPD}+R_{EGC}\right)}{\left(R_{GFPD}+R_{EGC}+R_{fault}+R_{recomb}+R_{comb}+R_{x}\right)} \quad (22)$$

In the simulations, the recombiner topology is not used ($D = 1$, $R_{recomb} = 0\ \Omega$), so the equation for I_{GFPD} shown as Equation (22) becomes:

$$I_{GFPD}=I_{leak}-\frac{I_{mp}\cdot\left(C\cdot R_{comb}+R_{x}\right)+I_{leak}\cdot\left(R_{comb}+R_{x}+R_{GFPD}+R_{EGC}\right)}{\left(R_{GFPD}+R_{EGC}+R_{fault}+R_{comb}+R_{x}\right)} \quad (23)$$

NUMERICAL SIMULATIONS OF BLIND SPOT FAULTS

As stated before, the analytical solutions assume that the PV modules continue to operate at MPP during the fault. In some situations, (for example, high cable impedance or lengths), some error is introduced. For this reason, computer circuit simulations were used to describe the behavior of PV systems for a wide variety of fault conditions. In the simulations, the PV modules are modeled as non-linear circuits, which are difficult to describe analytically (Zhao, Lehman, de Palma, Mosesian, & Lyons, 2011; Castaner & Silvestre, 2002).

A common method of circuit simulation is SPICE, originally developed at the University of California, Berkeley Electronics Research Laboratory in 1973 (Nagel & Pederson, 1973). SPICE is a general-purpose, open source, analog circuit simulator used to predict circuit behavior. In this work, the program MacSPICE, a derivative of SPICE3f4, was used to analyze the behavior of PV systems in various array configurations and ground fault conditions.

PV Array Simulation Setup

For the purposes of this work, the one-diode model is constructed to approximate a nearly perfect photovoltaic module. The current source is set to supply 2.5 A at short circuit, the diode has an ideality factor of N = 80, the shunt resistance is set $1 \cdot 10^{20} \Omega$, and the series resistance is set to 10 m Ω. This module gives an IV curve with I_{sc} of 2.5 A, V_{oc} of 56 V, and P_{mp} of 118 W. The MPP has a current of $I_{mp} = 2.4$ A and a voltage of $V_{mp} = 49.2$ V. These values were chosen to approximate the operation of modules in a 600 V array at Sandia's Distributed Energy Testing Laboratory on a summer day.

The model of a PV array is composed of a number of strings in parallel (as many as 201). Each string is composed of seven modules in series. Each module is connected to a bypass diode ($I_{sat} = 4.7 \cdot 10^{-12}$ A, N = 1). The array is wired to a resistor, as a basic approximation of the real input impedance of an inverter. The resistance connected to the array in all the simulations is set at the resistance required to generate maximum PV power, R_{mp}, of the unfaulted array.

The SPICE model was created with the internal resistance of the conductors and GFPD fusing, as shown in *Figure 1* in order to investigate ground faults involving the negative CCC. Arrays were simulated with each DC home run cable from the PV to the combiner box totaling 0.25 Ω (~80 feet of coated copper 12 American wire gauge [AWG] cabling at 3.125 m Ω/ft). Prior to each string being combined, the positive DC cable is connected to an overcurrent protection device with 0.077 Ω resistance (4 A KLKD Littelfuse [Littelfuse, 2011] rated for $1.56 \cdot I_{sc}$). The combiner box is connected to the inverter through cabling with an impedance of 0.00165 Ω (~50 feet of coated copper 400 circular mil [kcmil] cabling at 0.033 mΩ/foot). The ground fault is modeled by a resistor connected from the negative CCC to ground through the 0.041 Ω EGC (determined from field measurements [Ball et al., 2013, in press]). On the faulted string in *Figure 3,* the PV cabling resistance is split by the fault. This was done so that, by altering the resistance before and after the fault, the position of the fault in the PV cabling could be varied. The value of the inverter resistor is set to the MPP of the unfaulted array. The negative inverter connection is connected to ground through the GFPD.

Simulation Results

To investigate the effect of GFPD resistance on fault current, simulations were carried out for GFPD resistances of 85.5, 22, 8.16, 0.252, 0.124, and 0.0363 Ω (LittelFuse KLKD resistances for 0.1, 0.25, 0.5, 1, 2, and 5 A fuses [Littelfuse, 2011], respectively) with fault resistances of 0.1, 1, and 25 Ω. *Figure 10* shows the results of the simulations for 1, 2, and 5 A GFPD fuses and fault resistances of 0.1 and 1 Ω. Simulations with a 1 A (0.252 Ω), 2 A (0.125 Ω), and 5 A (0.0363 Ω) are shown as red, purple, and orange points, respectively. Triangles indicate a fault resistance of 0.1 Ω while circles represent a 1 Ω resistance. Solid lines at 1, 2, and 5 A denote the fuse ratings with color corresponding to the fuse trip point. The GFPD current calculated by Equation (18) is denoted by a dashed line for each set of fuse and fault resistances.

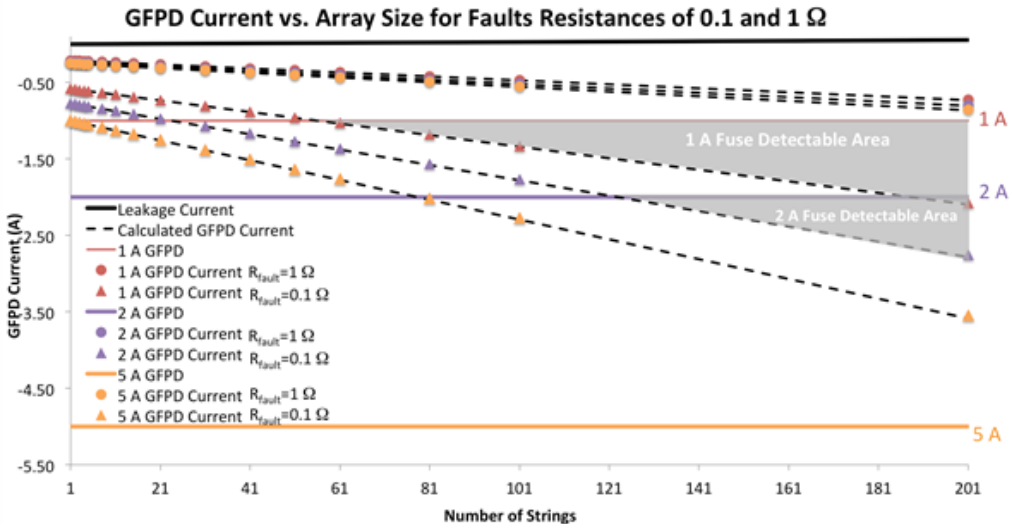


Figure 10. Graph of GFPD current vs. array size for various GFPD and fault resistances. The color of the line indicates GFPD resistance. Red traces denote 1 A (0.252 Ω), while purple and orange traces denote 2 A (0.124 Ω), and 5 A (0.0363 Ω), respectively. Only the 1 A and 2 A fuses are sensitive enough to trip due to the blind spot fault. The range in which I_{GFPD} is larger than the trip point is colored in gray.

The GFPD current is linear with the number of strings for all GFPD fuse ratings and fault resistances. Also, for all arrays up to 201 strings, only the 1 A and 2 A GFPDs (at fault resistance of 0.1 Ω) provide enough GFPD current to trip the fuse (colored regions denote where $I_{fault} > I_{GFPD}$). The 1 A GFPD only detects the ground fault in arrays larger than 56 strings while the 2 A GFPD detects faults in arrays larger than 124 strings. The orange traces do not reach 5 A even for 201 strings, so a 5 A GFPD would not trip for a blind spot ground fault of 0.1 or 1 Ω.

It is tempting to believe that decreasing the fuse rating will increase the number of detectable blind spot faults. However, the decrease in trip point is more than offset by the increased GFPD resistance, so fuses with low ratings will detect fewer blind spots. *Figure 11* shows the simulation results for 0.1 (green), 0.25 (purple), and 0.5 A (blue) GFPD fuse ratings at R_{fault} of 0.1 and 1 Ω. In each case, due to the increase fuse resistance, the GFPD current is far too small to trip the fuses.

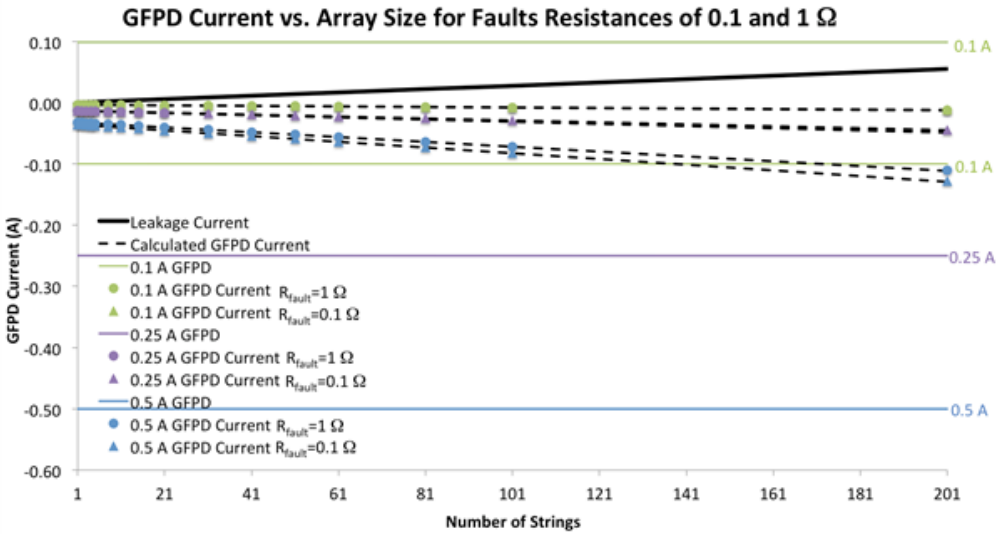


Figure 11. Graph of GFPD current vs. array size for various GFPD and fault resistances. The color of the line indicates GFPD resistance. Green traces denote 0.1 A (85.5 Ω), while purple and blue traces denote 0.25 A (22 Ω), and 0.5 A (8.16 Ω), respectively. Even though the fuses have low trip points, due to the increased fuse resistance, the GFPD current is below the fuse trip point and the blind spot window is increased.

Table 1 summarizes the simulation results for GFPD current at different fault resistance and fuse ratings. The color of the cell denotes whether it is possible to detect a blind spot fault. Only the 1 A and 2 A fuses at $R_{fault} = 0.1\ \Omega$ have the combination of low trip point and low fuse resistance needed to detect the blind spot fault for large array sizes (more than 56 and 124 strings, respectively). Thus, to limit the size of the blind spot, fuse rating and fuse resistance must both be considered and optimized.

Table 1.
GFPD Current for Various Fault Resistances and Fuse Ratings

Fuse (A)	Rfault (Ω)	I_{GFPD} (A)	Minimum Number of Strings to Detect Fault (0.98 kW/string)
0.1	0.1	0.0126 A @ 201-string	>201
	1	0.019 A @ 201-string	>201
	25	0.00259 A @ 201-string	>201
0.25	0.1	0.0486 A @ 201-string	>201
	1	0.0446 A @ 201-string	>201
	25	00608 A @ 201-string	>201
0.5	0.1	0.0128 A @ 201-string	>201
	1	0.0111 A @ 201-string	>201
	25	0.00862 A @ 201-string	>201
1	0.1	1.00 A @ 56-string	56
	1	0.727 A @ 201-string	>201
	25	0.0113 A @ 201-string	>201
2	0.1	2.004 A @ 124-string	124
	1	0.801 A @ 201-string	>201
	25	0.0111 A @ 201-string	>201
5	0.1	3.56 A @ 201-string	>201
	1	0.856 A @ 201-string	>201
	25	0.0113 A @ 201-string	>201

Note. The color of the cell indicates if a blind spot fault is detectable. Only the 1 A and 2 A fuses (at $R_{fault} = 0.1\ \Omega$) have both a low enough trip point and a low enough resistance to detect the blind spot fault for array sizes larger than 56 and 124 strings, respectively.

GFPD Current During High-Impedance Blind Spot Ground Faults

Based on the previous results, one may expect that the direction of the GFPD current could indicate blind spot ground faults, but this is not failsafe. *Figure 12* shows the GFPD current for 0.1, 0.25, and 0.5 A GFPD fuses for $R_{fault} = 25\ \Omega$. In these simulations, there are two opposing currents through the GFPD: (1) the positive current from the array leakage, and (2) the negative current from the fault. For larger fault resistances, the current through the GFPD *does not* switch direction for larger arrays because the backfed fault current is smaller than the leakage current for large arrays. In other words, the leakage current per additional string is larger than the fault current per additional string. *Figure 12* shows this current contribution per string for module leakage and fault current as a function of fault resistance. For a 1 A GFPD with a 15 Ω or larger fault, the module leakage increases faster than fault current, so, for larger arrays, the GFPD current will not reverse direction.

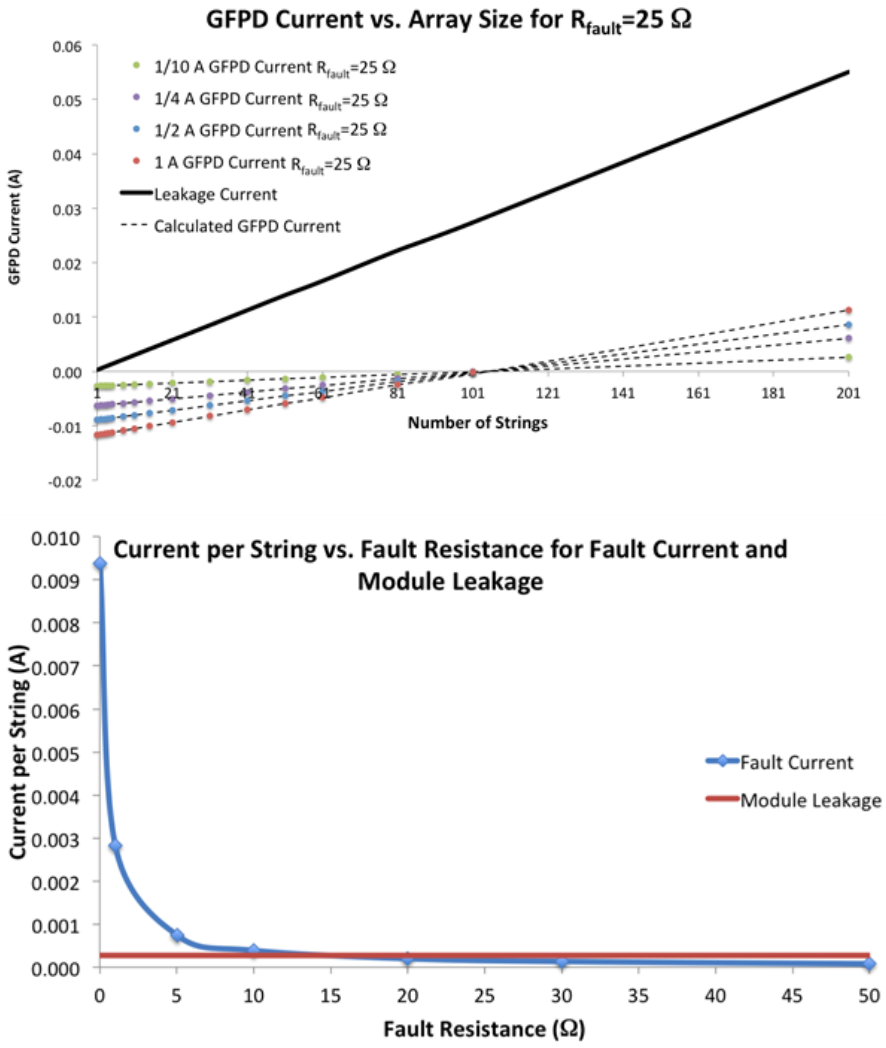
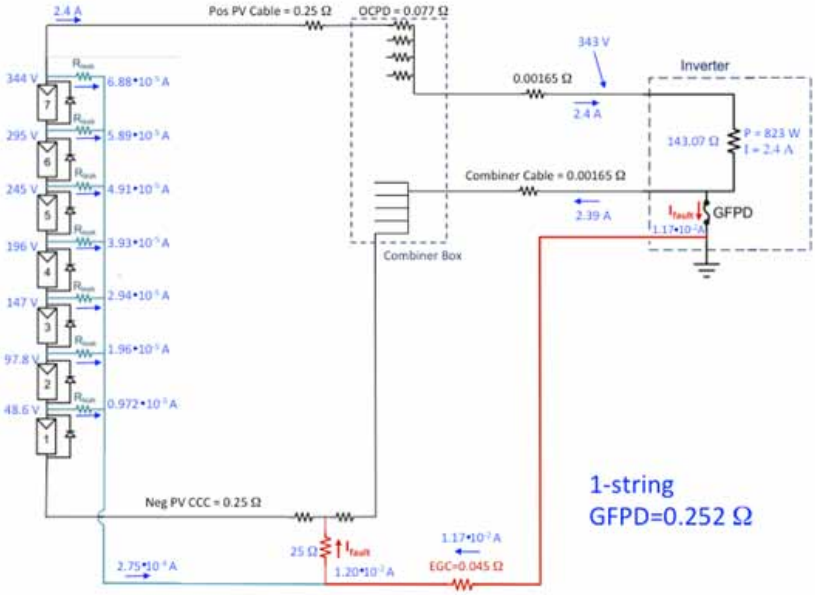
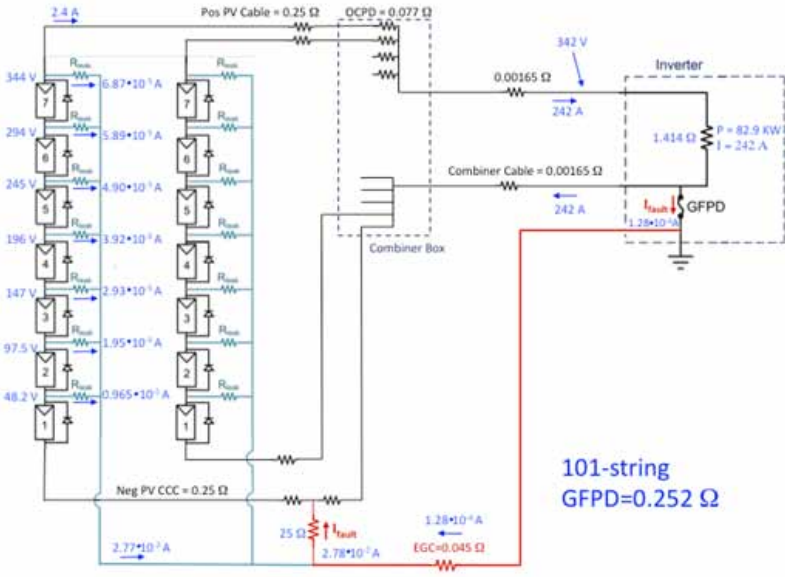


Figure 12. (top) Graph of GFPD current vs. array size for fault resistance of 25 Ω. The direction of the GFPD current will not change at an array size of 105 strings, because for large R_{fault} values and large array sizes, the leakage current is larger than the fault current. (bottom) Graph of current per string as a function of fault resistance with $I_{leak} = 100$ μA/module and $R_{GFPD} = 0.252\ \Omega$. For fault resistances of more than 15 Ω, the module leakage is larger than fault current, indicating that, as array size increases, the GFPD current will not reverse.

Figure 13 shows the circuit schematic for a 25 Ω fault resistance for array sizes of one, 101, and 201 strings. For a one-string array, the fault current is a hundred times larger than the leakage current. For a 101-string array, the leakage current and fault currents are approximately equal, so the GFPD current is nearly zero. For a 201-string array, the leakage current is larger than the fault current, and the GFPD current does not reverse direction.

These results indicate that for residential and smaller commercial-scale arrays, it would be possible to detect a blind spot fault by monitoring the direction of GFPD current. To determine the range of fault resistances that could be detected using this technique, simulations were performed for different array sizes varying R_{fault}. As fault resistance increases, the array size decreases for which there is a GFPD current reversal. *Figure 14* shows the value of GFPD current vs. fault resistance for array sizes of eight, 21, 51, 101, and 201 strings with a 0.252 Ω (1 A) GFPD. The inset shows the crossover points. The fault resistance crossover point for larger array sizes is at a smaller R_{fault} due to the large amount of leakage current. For example, for an eight-string array, due to the smaller array size, the crossover would be at more than R_{fault} = 110 Ω, but the 201-string array could only detect the blind spot using a change in GFPD current if the fault is less than about 20 Ω.





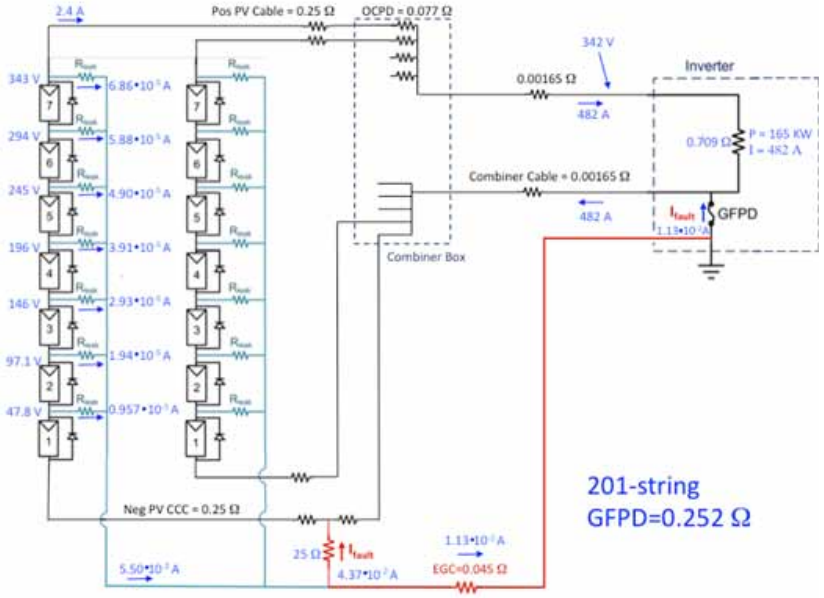


Figure 13. Three circuit schematics illustrating the reversal of GFPD current as array size increases (top). Circuit schematic of a one-string array with $I_{leak} < I_{fault}$ (middle), 101-string array with $I_{leak} \approx I_{fault}$ (bottom), and 201-string array with $I_{leak} > I_{fault}$.

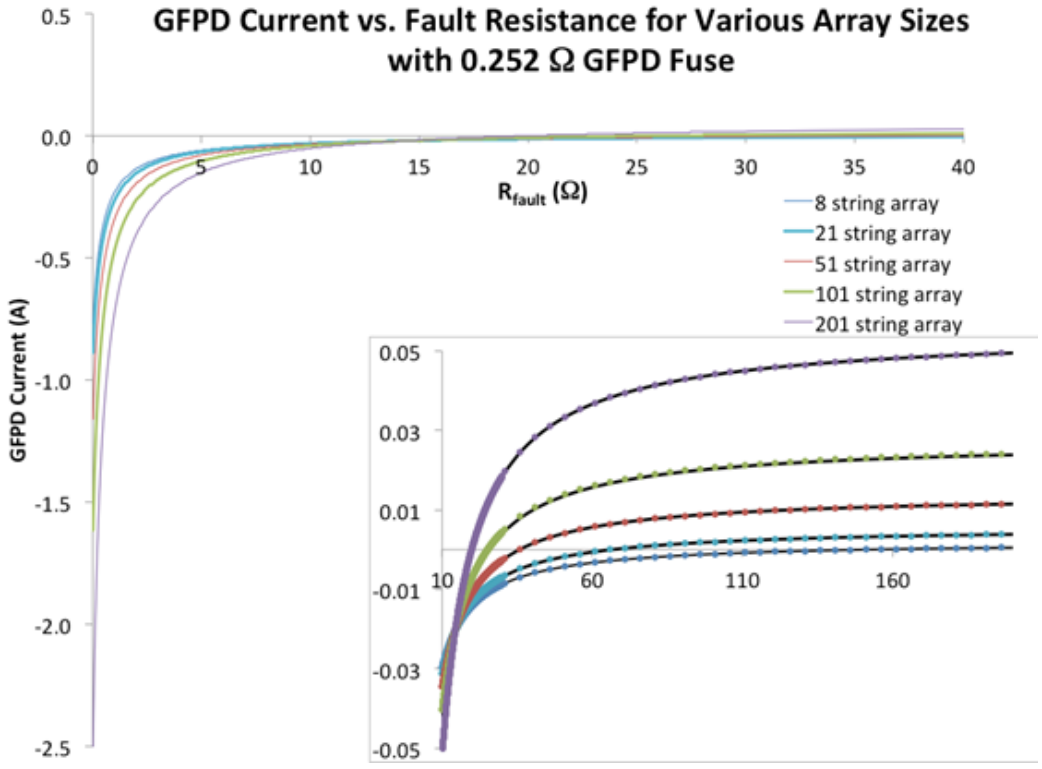


Figure 14. GFPD current as a function of fault resistance for various array sizes. The inset shows the crossover points for each array size.

Parametric Study of GFPD Current

As is apparent from Equation (22), the value of GFPD current is dependent on a number of parameters including number of strings (C), combiner cabling resistance (R_{comb}), resistance of the faulted section of PV cabling (R_x), GFPD resistance (R_{GFPD}), EGC resistance (R_{EGC}), and fault resistance (R_{fault}). In this section, a study of GFPD current is carried out by varying these system resistances across ranges denoted by *Table 2*. By determining how GFPD current varies with other parameters, it may be possible for system designers to decrease the blind spot window by maximizing GFPD current.

Table 2.
Nominal and High Values of the Parametric Resistances

Parameter	Nominal Value (Ω)	Low Value (Ω)	% Nominal	High Value (Ω)	% Nominal
R_{fault}	--	0	--	10	--
R_{GFPD}	0.252	0.01	3.97	100	39,682
R_{EGC}	0.041	0.001	2.44	10	24,390
R_x	0.125 (40 ft)	0.002 (0.64 ft)	1.60	10 (3,200 ft)	8,000
R_{comb}	0.00165 (50 ft)	$1 \cdot 10^{-5}$ (0.30 ft)	0.61	0.3 (9,090 ft)	18,182

Note. A parametric analysis was completed for each parameter for the range of resistances listed above.

Figure 15 shows the results of the parametric analysis for GFPD current as a function of string number (top), and fault resistance (bottom). *Figure 16* shows the results of the parametric analysis for GFPD current as a function of EGC resistance (top), and GFPD resistance (bottom) for a 101-string array. The blue line indicates the analytical solution presented in Equation (22) while the black dots indicate the results of the SPICE simulation. The variables used in the simulation are listed in the corresponding graph. There is excellent correlation between the analytical equation and the SPICE simulations for this set of parametric analyses.

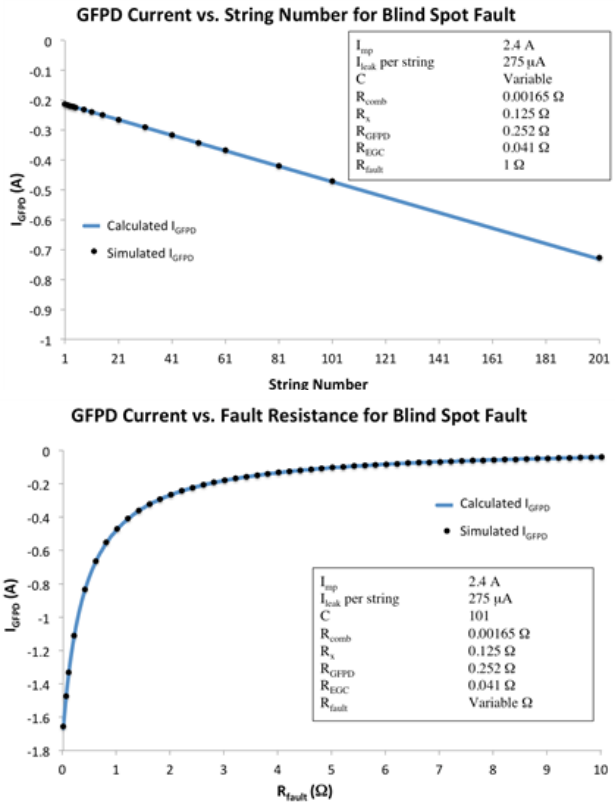


Figure 15. Comparison of analytical equation (blue trace) and SPICE simulations (black dots) for GFPD current as a function of other parasitic resistances (top) and GFPD current vs. number of strings in array (bottom). The variables used in the SPICE simulations are listed on each graph. In each set of simulations, the simulation results match the expected analytical solution.

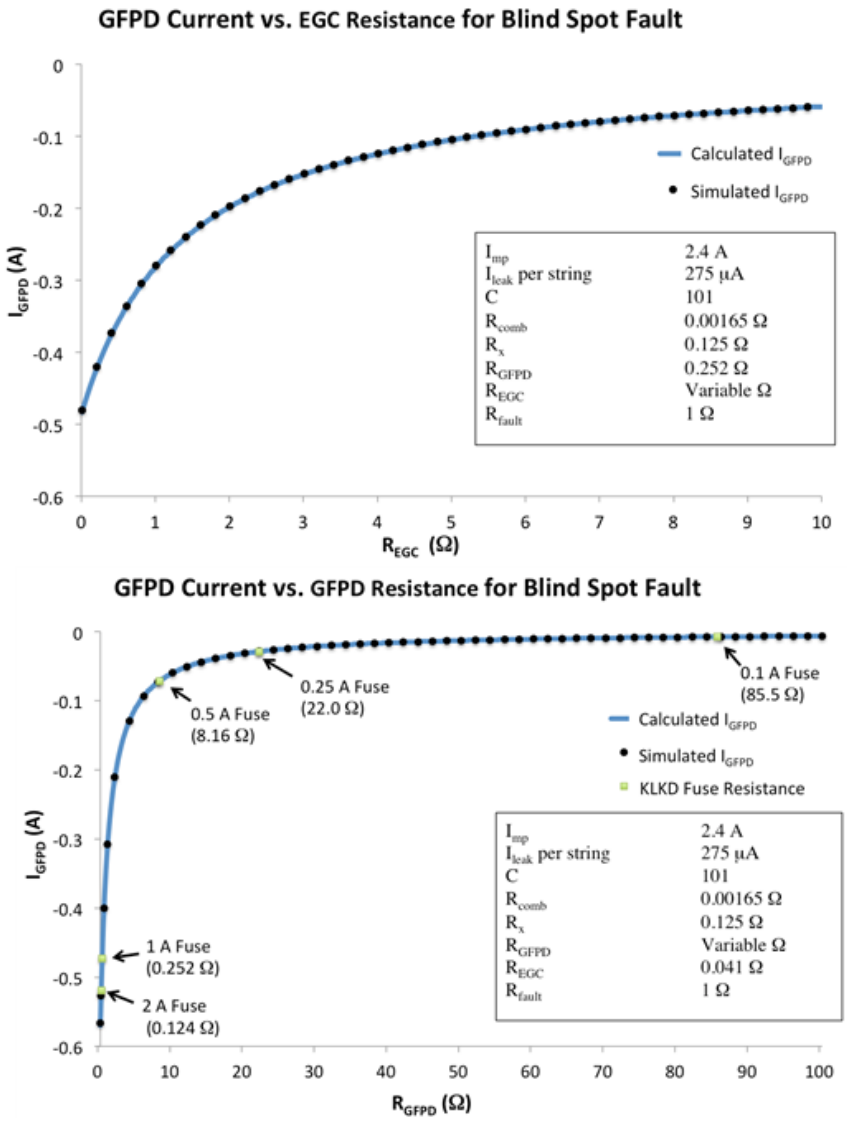


Figure 16: GFPD current vs. EGC resistance (top), and GFPD current as a function of GFPD after resistance (bottom). Green points indicate intrinsic resistance of KLKD "midget" fuses of various sizes from 0.1 to 2 A. The variables used in the SPICE simulations are listed on each graph. In each set of simulations, the simulation results match the expected analytical solution.

Figure 17 (top) shows the parametric test results of GFPD current as a function of the faulted PV cabling resistance (R_x). For the PV cabling resistance, the SPICE simulations follow the analytical solution quite closely for small resistances. However, as the PV cabling resistance increases to values in the multiple ohm range, the simulation results are slightly smaller than expected. This is due to an assumption during the derivation of the analytical equation that each string stays at MPP. While this assumption is true for the majority of resistances, it may not hold true as the cabling resistance increases.

Figure 17 (bottom) shows the array voltage as a function of resistance changes. As the value of $R_{fault,}$ $R_{EGC,}$ and R_{GFPD} change, there is a small impact on the array voltage (less than 0.5 V), so the simulation and analytical results match well. The assumption that each string stays at MPP does not hold as well when R_x changes, so there is a larger effect on the array voltage (black dots and blue crosses). As the value of R_x approaches 10 Ω, the faulted string voltage changes by as much as 2 V. This small change in operation voltage is enough to cause the slight GFPD current mismatch between the simulation and analytical solutions.

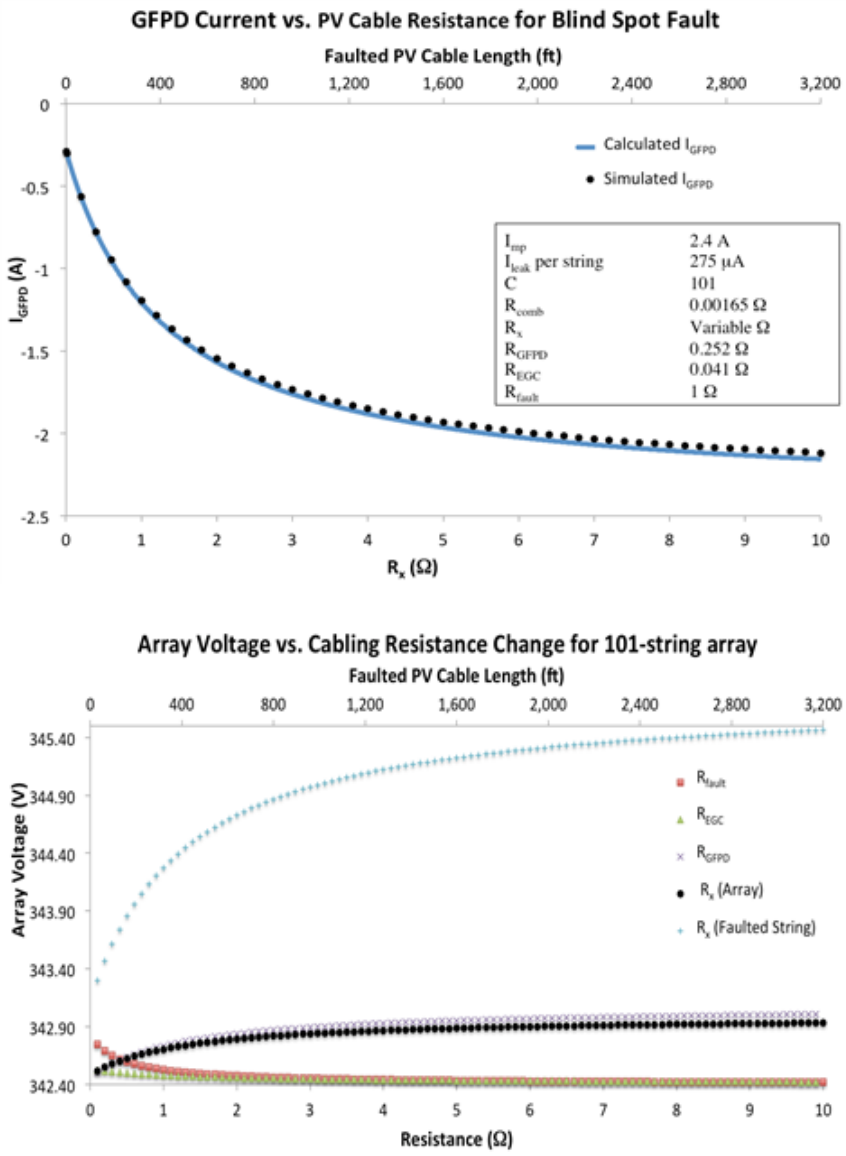


Figure 17. (top) GFPD current vs. PV cabling resistance of faulted string as determined through calculation of the analytical solution (blue trace) and SPICE simulations (black dots). The results match well for small resistances, but diverge slightly as R_x increases. This is due to the fact that as R_x increases, the operating voltage of the faulted string (bottom) can no longer be assumed to be at V_{mp} both before and after the fault.

The mismatch between simulation results and the analytical solution is similar for combiner cabling impedance changes (*Figure 18*). As the combiner cabling impedance increases to an appreciable fraction of the inverter impedance, the assumption that the array stays at MPP before and after the fault is no longer valid (*Figure 18,* right). This disruptive effect of the cabling impedance on the array voltage is much larger for large arrays because the inverter impedance is so low. This means even for small combiner cabling resistances, the array cannot be assumed to stay at MPP. Because smaller arrays have larger inverter impedances, the assumption holds for much larger cable impedances. As a result, the analytical solution is much closer to the simulation results as the array size decreases (*Figure 19*).

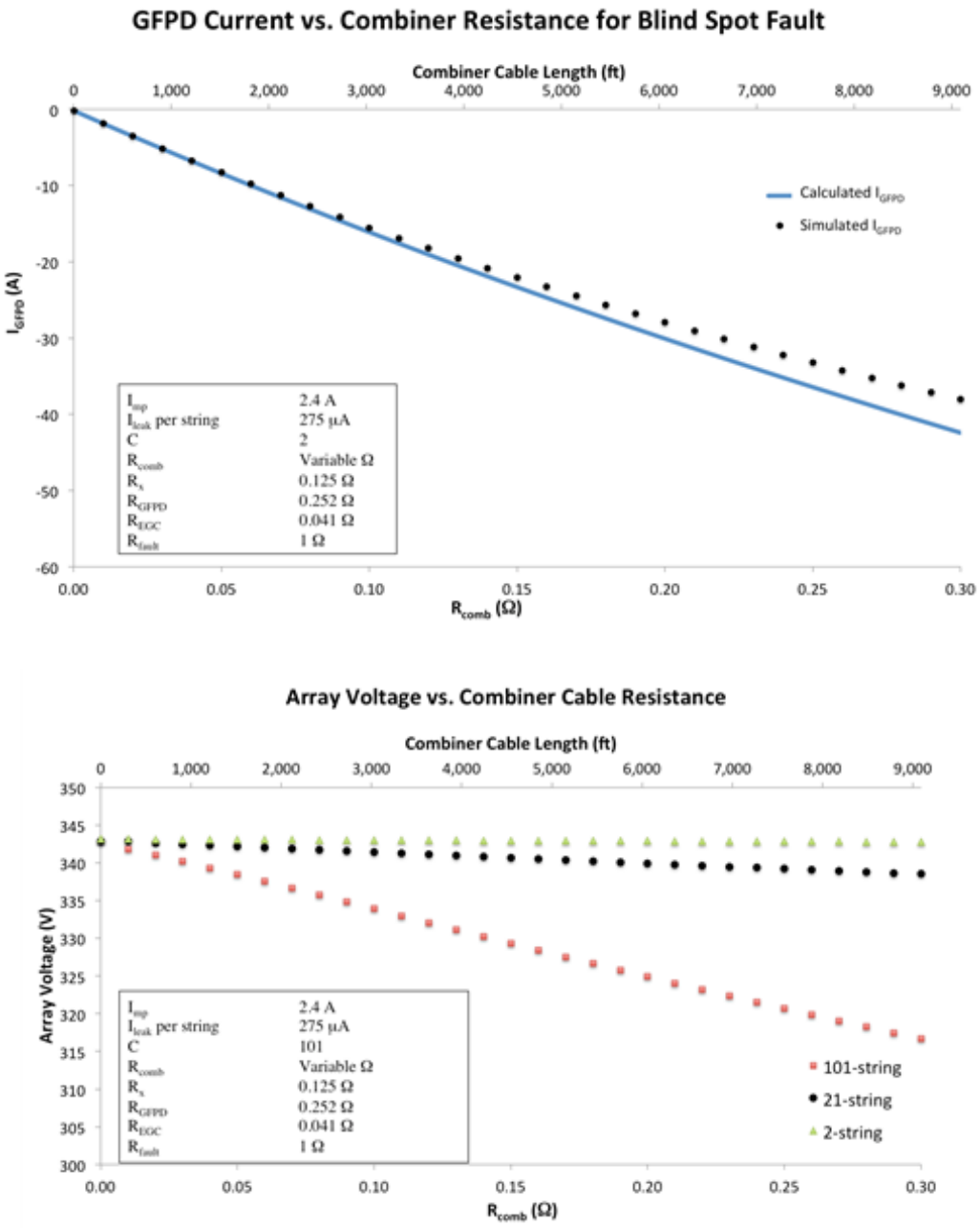


Figure 18. (top) GFPD current as a function of combiner cable resistance. The analytical calculation (blue trace) diverges from the SPICE simulation results as the resistance increases (black dots). This is due to the fact that as the cabling resistance becomes an appreciable function of inverter impedance, the array voltage can no longer be assumed to stay at MPP throughout the fault (bottom). The cabling impedance effect on array voltage is much larger for large arrays because the inverter impedance is so small.

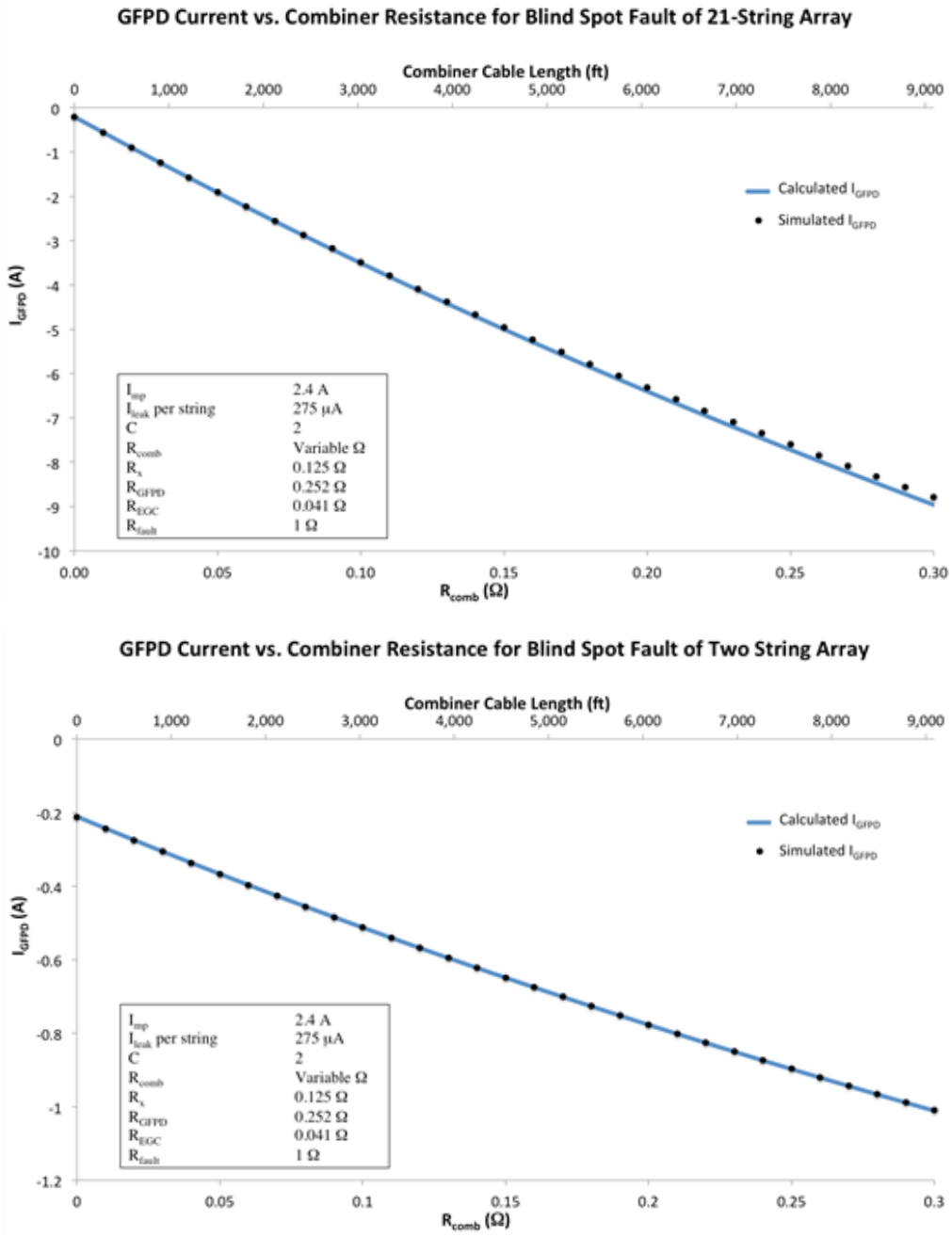


Figure 19. As the array size decreases, the analytical solution and SPICE simulation results begin to merge. While the mismatch is large for large array sizes, the mismatch is smaller as the array size goes to 21 strings (top) and is very close for a two-string array (bottom). The analytical and numerical results merge because, as inverter impedance increases, the PV cabling resistance has a much smaller effect on array voltage and the assumption that the array stays at V_{mp} is more correct.

Summary and conclusions

In this work, analytical and numerical solutions to determine GFPD current for ground fault blind spot cases (where a fault occurs to the grounded CCC) were presented. The results demonstrated the influence of fault and conductor resistances on the detectability of different blind spot ground faults. Blind spot detection is challenging due to the small GFPD current levels and the large influence of fault, GFPD, and cabling resistances on GFPD current. The SPICE model and analytical results were used to determine trends for various ground fault conditions and to ascertain potential benefits of reducing the fuse ratings in PV systems. Decreasing the GFPD ratings to 1 A for large installations would not increase the number of nuisance trips, but would protect against a wider range of ground faults. However, further decreasing the fuse ratings below 1 A does not improve the number of faults that can be detected due to larger internal GFPD resistances and a subsequent decrease in fault current. In fact, because the ground fault fuse resistances increase from 1 A to 0.1 A, more blind spot faults can be detected with the 1 A fuse. Unfortunately, fewer ground faults to other parts of the array can be detected (IEC, 2005), so it is necessary to carefully select the GFPD rating to optimize the types of ground faults that can be detected.

While it may not be possible to provide complete detection for both faults within the array and faults to the grounded CCC using a fuse, the simulations indicate that the detection window for blind spot faults can be optimized by:

1. minimizing leakage current, because fault current is the opposite direction of leakage current and large leakage currents will inhibit the detection of negative CCC faults;

2. decreasing the fuse sizing for large arrays below UL 1741 requirements to 1 A, because module leakage current will be too small to result in nuisance tripping and it will trip on more ground faults;

3. preventing the reduction in fuses below 1 A because the internal resistance of the fuse prevents the fault current from passing through the GFPD;

4. monitoring both GFPD current magnitude and direction (especially for smaller array sizes), because GFPD current can change direction when a negative CCC ground fault occurs; and

5. employing other fault detection tools such as differential current measurement and insulation monitoring (see [Ball et al., 2013, in press] for more information on alternative ground fault detection techniques and suggestions).

ACRONYMS

A	ampere
AWG	American wire gauge
C	number of strings
CCC	current-carrying conductor
CdTe	cadmium telluride
DOE	U.S. Department of Energy
EGC	equipment grounding conductor
EMI	electromagnetic interference
GFDI	ground fault detector/interrupter
GFPD	ground fault protection device
IEC	International Electrotechnical Commission
IV	current voltage
I_{leak}	array leakage current
I_{mp}	maximum power current
I_{sat}	module diode leakage current
KCL	Kirchoff's Current Law
kcmil	circular mil
KVL	Kirchoff's Voltage Law
m^2	square meter
MΩ	megaohm
MPP	maximum power point
NREL	National Renewable Energy Laboratory
Ω	ohm
PARC	Palo Alto Research Center
P_{mp}	Power at Maximum Point
PV	photovoltaic
R_{comb}	resistance of combiner cabling
R_{EGC}	resistance of EGC
R_{fault}	fault resistance
R_{GFPD}	GFPD resistance
R_{leak}	leakage current to ground
R_{PV}	resistance of PV cabling
R_{recomb}	recombiner cable resistance
R_x	resistance of portion of PV cabling included in fault loop
R_y	resistance of portion of PV cabling nots included in fault loop
Solar ABCs	Solar America Board for Codes and Standards
SPICE	Simulation Program with Integrated Circuit Emphasis
µA	microampere
V	volts
V_{mp}	voltage at maximum power

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PV System Operations and Maintenance Fundamentals

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August 2013

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EXECUTIVE SUMMARY

Until recently, the U.S. photovoltaics (PV) Industry has focused on the development of PV module technology, inverters, components, and manufacturing. The United States now has more than 7.4 gigawatts (GW) of installed capacity, comprising more than 300,000 systems (Sherwood, 2013).

In light of this growth and the continued maturation of the PV market, the industry must focus on operating and maintaining systems. PV installation lifetimes are expected to be 25 years or more, so safe and proper maintenance is an integral part of successful and reliable operation. System operations and maintenance (O&M) is a broad area, and is the continuing focus of several industry/government/national laboratory working groups that are working to better define the issues and develop consensus approaches. In the interim, the Solar America Board for Codes and Standards (Solar ABCs) has prepared an O&M introductory report that includes practical guidelines for PV system maintenance and options for inspection practices for grounded PV systems. This report does not cover bi-polar, ungrounded, stand-alone, or battery backup systems.

With the understandable focus on maximizing return on investment (ROI) and system production, system uptime is a key O&M objective. For example, inverters that are offline can have a dramatic negative impact on the ROI of a PV system. Inverter failure rates are important to ROI, but equally or even more important than how often an inverter goes offline is how quickly it can be placed back into service. Diagnosing and correcting power production deficiencies is also important to maximizing availability of system components and ROI. This report includes the current, commonly used diagnostic and troubleshooting procedures for inverter malfunctions or failures and associated reduced power production.

The intent of this report is to help qualified individuals maintain and inspect PV systems safely. Qualification to conduct such inspections is earned by direct on-the-job training under qualified supervision or through training programs offered by accredited educational institutions or manufacturers. It should be noted that many testing and maintenance activities require two people to be performed safely and efficiently. Currently, an employee who is being trained for a task, demonstrates the ability to perform duties related to that task safely, and is under the direct supervision of a qualified person is usually considered to be a qualified person.

This report also addresses currently known major safety requirements during PV servicing and repair, including the proper use of lockout/tagout procedures, the use of personal protective equipment, procedures for safely disconnecting live circuits, and appropriate observation of and compliance with all PV-specific system signage and warnings. In addition, it includes information about routine preventive maintenance and emergency shutdown procedures.

Newer PV systems may use devices that are not covered in this document, and technicians should contact the manufacturer for instructions on operating and maintaining such devices. This report also does not cover all the variations in equipment and measurement techniques that are available to qualified personnel, and there are suitable substitutes available for the equipment listed here. Readers should also be aware that PV systems are evolving to higher voltages, and voltmeters and other devices must be rated for use at the higher 1,000-volt level.

Conclusions

The conclusions of this introductory report include:

- To maintain quality control and safety standards, it is important that only qualified personnel work on PV installations. The authors suggest minimum skill and knowledge guidelines for PV technicians.
- Safety is a serious concern when servicing PV installations. Early PV systems often had maximum system voltages less than 50 V_{dc}, but 1,000 V_{dc} systems are now allowed by code in commercial and large-scale installations.
- Qualified personnel should always work in teams of two people when working on live equipment, and there should always be at least two qualified persons trained in cardiopulmonary resuscitation on the jobsite.
- Not all installations have appropriate signage, and qualified persons must be trained to recognize potential hazards with or without signage present.
- System uptime and availability is a key objective of O&M, and inverters that are offline can have a dramatic negative impact on the ROI of a PV system.
- Low power production also impacts ROI, and O&M personnel need effective strategies for identifying and correcting problems quickly.

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Solar America Board for Codes and Standards

The Solar America Board for Codes and Standards (Solar ABCs) provides an effective venue for all solar stakeholders. It consists of a collaboration of experts who formally gather and prioritize input from groups such as policy makers, manufacturers, installers, and large and small-scale consumers. Together, these entities make balanced recommendations to codes and standards organizations for existing and new solar technologies. The U.S. Department of Energy funds Solar ABCs as part of its commitment to facilitate widespread adoption of safe, reliable, and cost-effective solar technologies.

For more information, visit the Solar ABCs website:
www.solarabcs.org

Acknowledgments

This material is based upon work supported by the U.S. Department of Energy under Award Number DE-FC36-07GO17034. The authors sincerely thank the following individuals who have provided helpful reviews and comments for this report: Greg Ball (DNV), Ward Bower (Ward Bower Innovations LLC), Bill Brooks (Brooks Engineering), Dave Click (Florida Solar Energy Center), Marv Dargatz, and Andrew Rosenthal (New Mexico State University).

TABLE OF CONTENTS

DISCLAIMER 2

EXECUTIVE SUMMARY 3

AUTHOR BIOGRAPHIES 5

SOLAR ABCS 5

ACKNOWLEDGMENTS 5

INTRODUCTION 7
- Qualified Personnel 7

SAFETY REQUIREMENTS 9
- Lockout/Tagout 9
- PPE and Other Safety Equipment 10
- Safe Operation of Electrical Disconnects 10
- PV-Specific Signage and Warnings 11

ROUTINE SCHEDULED PREVENTIVE MAINTENANCE 13
- General Site Annual Inspection 13
- Detailed Visual Inspection 13
- Manufacturer-Specific Inverter Inspection 14
- Manufacturer-Specific Tracker Inspection 15
- Manufacturer-Specific Data Acquisition System Inspection 16

GENERAL ISOLATION PROCEDURES 17
- Energized Components 17
- Inverter Pad Equipment 17
- Transformer Isolation 17

FAILURE RESPONSE 18
- Emergency Shutdown 18
- Isolation Procedure—Inverter Pad Equipment 18
- Isolation Procedure—Field Combiner Box 18
- Isolation Procedure—Modules and String Wiring 19

INVERTER TROUBLESHOOTING AND SERVICE 20
- Inverter Troubleshooting 20
- Inverter Service Procedures 21

DIAGNOSING AND TESTING FOR LOW POWER PRODUCTION 22
- Diagnostic Overview 22
- Diagnostic Testing 23
- *Infrared (IR) Image Procedure* 23
- *Megohmmeter Testing* 25
- *Fuse Checks* 29
- *DC System V_{oc} Checks* 30
- *DC System I_{mp} Checks* 32
- *Grounding System Integrity Checks* 33
- *DAS Check* 33
- *Ground Fault Troubleshooting* 37
- *Array Washing Procedure* 39
- *Vegetation Management* 41
- *System Warranties* 41

CONCLUSIONS 42

ACRONYMS 43

GLOSSARY 44

REFERENCES 45

Introduction

For most of its history, the U.S. photovoltaics (PV) Industry has focused on the development of PV module technology, inverters, components, and manufacturing. These efforts have helped to advance the state of the art for PV systems worldwide. The United States now has more than 7.4 gigawatts (GW) of installed capacity, comprising more than 300,000 systems (Sherwood, 2013).

In light of this growth and the continued maturation of the PV market, the industry must focus on operating and maintaining systems. PV installation lifetimes are expected to be 25 years or more, so safe and proper maintenance is an integral part of successful and reliable operation. System operations and maintenance (O&M) is a broad area, and is the continuing focus of several industry/government/national laboratory working groups. These groups will better define the issues and develop consensus O&M approaches over the next few years. In the interim, Solar ABCs has prepared an O&M introductory report that includes practical guidelines for PV system maintenance and options for inspection practices for grounded PV systems. It is intended for mono-polar, grid-connected PV systems, and does not explicitly cover bi-polar, ungrounded, stand-alone, or battery backup systems. Off-grid systems have many of the same components, however, and portions of the guidelines can be used for inspection or maintenance of off-grid systems.

Qualified Personnel

This report is intended to help qualified individuals maintain and inspect PV systems safely. The U.S. Department of Labor's Occupational Safety and Health Administration (OSHA) defines a qualified person as one who has received training and has demonstrated skills and knowledge in the construction and operation of electrical equipment and installations and the hazards involved. The definition supplied in Article 100 of the National Electrical Code® *(NEC)* is very similar (NFPA, 2011a): "One who has skills and knowledge related to the construction and operation of the electrical equipment and installations and has received safety training to recognize and avoid the hazards involved."

Technicians can be qualified for some maintenance and service tasks but still be unqualified for others. Whether someone is a "qualified person" often depends on the specifics of the task at hand.

Qualification is earned by either direct on-the-job training under qualified supervision or through training programs offered by accredited educational institutions or manufacturers. Many testing and maintenance activities require two people to be completed safely and efficiently. An employee who is being trained for a task, demonstrates the ability to perform duties related to that task safely, and is under the direct supervision of a qualified person is usually considered to be a qualified person.

Additionally, in order to be considered a qualified person for PV service and maintenance, a person must be trained in and familiar with:

- the skills and techniques necessary to identify exposed live parts from other parts of electrical equipment,
- the skills and techniques necessary to determine the nominal voltage of exposed live parts,
- the clearance distances specified by OSHA in the Code of Federal Regulations (CFR) Part 1910.333(c) ("Working on or near energized parts") and the corresponding voltages to which the qualified person will be exposed,
- the pertinent sections of the *NEC*,
- the characteristics of PV sources and hardware typically used in PV systems, and
- the characteristics of the hardware used in the PV system the person is working on.

It is strongly recommended that anyone working around energized PV systems complete a minimum of the 10-hour OSHA-10 Construction Industry Training Program. Local jurisdictions may specify the necessary training, skills, certifications, or licenses required to perform the work discussed in this report. One indicator that a person may be qualified to work on many types of PV systems is to confirm that the person is a certified energy practitioner who has met the qualifications for and passed a certification exam.

SAFETY REQUIREMENTS

Safety begins with adequate planning and preparation. Effective safety policies must be in place and employees and contractors must be familiar with—and committed to following—safety procedures in order to prevent accident or injury.

Major safety requirements during PV servicing include the proper use of lockout/tagout procedures, the use of personal protective equipment (PPE), procedures for safely disconnecting live circuits, and appropriate observation of and compliance with all PV-specific system signage and warnings.

Lockout/Tagout

Lockout/tagout (LOTO) procedures are designed to ensure safe working practices and must be strictly followed whenever systems are de-energized prior to servicing. LOTO is covered by CFR, under 29 CFR 1910.147.

LOTO is required when energized equipment is serviced or maintained, safety guards are removed or bypassed, a worker has to place any part of his or her body in the equipment's point of operation, or hazardous energy sources are present.

Lockout/tagout steps include:

- notify others that the equipment will be shut down,
- perform a controlled shutdown to power down the equipment,
- open all of the energy isolating devices identified on the equipment's specific LOTO procedure,
- lock and tag all energy isolating devices,
- dissipate or restrain stored or residual energy,
- verify that the equipment is completely de-energized by attempting to cycle it, and
- verify that the equipment is completely de-energized by testing for voltage with a voltmeter.

Proper LOTO labeling includes:

- name of the person placing the LOTO and the date placed,
- details regarding the shutdown procedure for specific equipment,
- a list of all of the energy sources and isolating devices, and
- labels indicating the nature and magnitude of stored potential or residual energy within the equipment.

The lock placed on equipment during servicing should be removed only by the person who placed it. The lockout devices, such as padlocks, shall be approved for LOTO applications. OSHA provides variations of LOTO that may be used depending on an approved energy control program. Safety protocols need to be followed when re-energizing equipment, including notifying others that the system is about to be energized.

PPE and Other Safety Equipment

Service personnel must know what PPE is required for a specific task and wear it while completing the task. PPE includes fall protection, arc flash protection, fire-rated clothing, hot gloves, boots, and protective eyewear, among other items. PPE is designed to help minimize exposure to inherent system hazards. Identification of potential hazards is crucial to the process of selecting the appropriate PPE for the task at hand. All personnel working on or near PV systems should be trained to recognize hazards and choose the appropriate PPE to eliminate or reduce those hazards.

Rubber-insulating gloves, often referred to as "hot gloves," are the first line of defense against electric shock. They should always be worn with protective leather gloves over them and inspected before each use. Additionally, OSHA requires the gloves to be re-certified or replaced at regular intervals, beginning six months after they are placed in service. Insulated hand tools provide an additional layer of shock protection.

As PV systems get larger and direct current (dc) operating voltages up to 1,000 volts (V) become increasingly common, arc flash requirements are a growing concern and it is more common to see arc flash warning labels on combiner boxes and disconnects. Unfortunately for maintenance personnel, many existing PV systems have been installed without labels warning of arc flash hazard. Service personnel need to be able to perform on-site evaluations to determine when a higher category of PPE is required to perform the work. Tasks such as performing thermal imaging on operating inverters with opened coverings or doors or verifying voltages in switchgear commonly require arc flash rated PPE.

Even when not required by statute or regulations, general industrial safety equipment such as hardhats, safety glasses, boots, fire-rated clothing, and safety vests are strongly recommended when working on construction sites or around live electrical equipment. The jobsite also must be equipped with appropriate fire extinguishers and first aid supplies and all personnel must have proper training in their use. Lastly, at least two qualified people trained in cardiopulmonary resuscitation (CPR) should be on site at all times.

Safe Operation of Electrical Disconnects

Switching on or off an electrical contactor or disconnect is a process often taken for granted as safe but it can be one of the more dangerous tasks involved in maintaining a PV system. Workers must wear proper PPE when operating disconnects, and care should be taken to use the proper technique for throwing switches.

Some of the switches used to control the dc circuits of PV systems are not rated for load-break operation. Non-load-break-rated switches, which must be labeled as non-load-break-rated, must never be opened while the system is operating. Before opening a dc switch that is not rated for load break, the system should be shut down by turning off the connected inverter.

The hinges of most disconnect switches are on the left side of the switch and the handles are on the right. A recommended safety protocol is to follow the left hand rule, which involves standing to the right side of the switch and using the left hand to throw the switch. This ensures that the worker's body is not in front of the switch should an arc flash occur.

The proper technique for safely throwing an electrical disconnect includes:

- wear proper PPE,
- shut the system off at the inverter,
- stand to the right of the switch,
- grab the handle with the left hand,
- turn body and face away from the switch,
- close eyes,
- take a deep breath and hold it (to avoid breathing in flames if an arc flash occurs),
- throw (operate) the disconnect lever,
- use a properly rated voltmeter to confirm that no voltage is present on the disconnected circuit, and
- use LOTO methods to ensure the switch remains off.

PV-Specific Signage and Warnings

Article 690 of the *NEC* (NFPA, 2011b) covers the requirements for PV-specific signage and warnings that must be present on every PV system. Additional signage may also be required by the local jurisdiction or utility. These placards and warnings need to be visible to those working on or near the systems and should never be covered or painted over.

Early PV systems often operated with maximum system voltages less than 50 V_{dc}. Today, 600 V_{dc} systems are common and 1,000 V_{dc} systems are allowed by code in commercial and large-scale installations. Qualified personnel must use properly rated equipment and be trained for servicing the higher voltage systems.

Particular care must be taken to observe and follow warning labels reading "DO NOT DISCONNECT UNDER LOAD" located on module connections, combiner boxes, disconnects, and some inverter switches not designed as a load-break switch. Failure to heed these warning labels can lead to instrument malfunction, arcing, fires, and personnel injuries.

Although it is impossible to compile a list of universally applicable safety guidelines, the authors suggest the following steps as crucial to safe work:

- Before operating the PV system, read all instructions for each product.
- All system components must be assumed to be energized with maximum dc voltages (up to 1,000 V) until personnel verify that the voltage has been removed.
- All enclosure doors should remain closed with latches tightened, except when they must be open for maintenance or testing.
- Only qualified personnel who meet all local and governmental code requirements for licensing and training for the installation of electrical power systems with alternating current (ac) and dc voltages up to 1,000 V (or 600 V, when applicable) should perform PV system servicing.
- To reduce the risk of electric shock, only qualified persons should perform servicing other than that specified in the installation instructions.

- In order to remove all sources of voltage from the inverter, the incoming power must be de-energized at the source. This may be done by opening the ac disconnect and the dc disconnect. Follow manufacturer guidelines for specifics of how to de-energize the inverter. In addition, allow a minimum of five minutes for the dc bus capacitors to discharge after disconnecting the power, always testing that voltage is reduced to touch-safe levels (30 V_{dc}) before working on the system.
- Always follow LOTO procedures.
- Always check for ground faults. If there is a ground fault, there may be a voltage potential between the inverter and ground. Further, check that the normally grounded pole is properly grounded and has not been energized by a fault.
- Do not work alone when servicing PV equipment. A team of two is required until the equipment is properly de-energized, locked-out, and tagged-out. Verify with a meter that the equipment is de-energized.
- Do not open a string (also known as a source circuit) combiner fuse holder without first confirming that there is no current flowing on the circuit.
- Do not disconnect (unplug) module leads, jumpers, or homerun wires under load.

ROUTINE SCHEDULED PREVENTIVE MAINTENANCE

One of the most valuable techniques for identifying existing problems and preventing future problems is to walk the site and conduct a thorough visual and hands-on inspection of the PV system components. These inspections should be conducted at regular intervals, and personnel should use checklists developed for these periodic maintenance activities to ensure that the inspections are thorough and complete.

General Site Annual Inspection

At least once a year, O&M personnel should conduct a general inspection of the PV installation site. During this inspection, technicians should:

- ensure roof penetrations are watertight, if applicable;
- ensure roof drainage is adequate, roof drains are not clogged, and confirm that there are no signs of water pooling in the vicinity of the array;
- check for vegetation growth or other new shade items such as a satellite dish;
- check for ground erosion near the footings of a ground mount system;
- confirm proper system signage is in place;
- confirm appropriate expansion joints are used where needed in long conduit runs;
- confirm electrical enclosures are only accessible to authorized personnel, are secured with padlocks or combination locks, and have restricted access signage;
- check for corrosion on the outside of enclosures and the racking system;
- check for cleanliness throughout the site—there should be no debris in the inverter pad area or elsewhere;
- check for loose hanging wires in the array; and
- check for signs of animal infestation under the array.

Detailed Visual Inspection

The installation should be inspected regularly for issues that impact the physical integrity or performance of the PV system. A visual inspection should include the following actions:

- Inspect the inverter/electrical pad to make sure it does not show excessive cracking or signs of wear. The inverter should be bolted to the pad at all mounting points per the manufacturer installation requirements. Depending on the size, location, and accessibility of the system to unqualified personnel, the inverters, combiner boxes, and disconnect switches should require tools or have locks to prevent unauthorized access to the equipment.
- Look for warning placards including arc flash or PPE requirements for accessing equipment. Be sure to comply with all warning placards. If no placards are present, or if some placards are missing, make a note of it and install the missing placards during the maintenance visit. Consult the *NEC* and Underwriters Laboratories (UL) standards as well as the site host to determine signage requirements.

- Inspect PV modules for defects that can appear in the form of burn marks, discoloration, delamination, or broken glass.
- Check modules for excessive soiling from dirt buildup or animal droppings. (See Array Washing Procedure for proper procedures for cleaning an array.)
- Ensure that the module wiring is secure and not resting on the roof, hanging loose and exposed to potential damage, bent to an unapproved radius, or stretched across sharp or abrasive surfaces.
- Inspect racking system for defects including rust, corrosion, sagging, and missing or broken clips or bolts.
- If sprinklers are used to spray the array, check that the water is free of minerals (demineralized) as these minerals can cause gradual performance degradation.
- Inspect conduits for proper support, bushings, and expansion joints, where needed.
- In roof-mounted systems, check the integrity of the penetrations.
- In ground-mounted systems, look for signs of corrosion near the supports.
- Open combiner boxes and check for torque marks on the connections. Torque marks are made when lugs have been tightened to the proper torque value. Ideally they are applied during initial installation, but if not, the technician can mark the lug after torquing during a maintenance visit. A proper torque mark is made with a specialized torque marking pen. The mark is a straight line through the lug and the housing. Over time, if the line separates between the lug and the housing, it shows that the lug has moved and needs to be re-torqued. Look for debris inside the boxes and any evidence of damaging water intrusion. Look for discoloration on the terminals, boards, and fuse holders.
- Open the door to the disconnect(s) and look for signs of corrosion or damage. Check to make sure the cabinet penetrations are properly sealed and there is no evidence of water ingress. Check for torque marks on the terminals.
- Perform a visual inspection of the interior and exterior of the inverter. Look for signs of water, rodent, or dust intrusion into the inverter. Check for torque marks on the field terminations.
- If a weather station is present, ensure that the sensors are in the correct location and at the correct tilt and azimuth. A global horizontal irradiance sensor should be flat, and a plane of array irradiance sensor should be installed to the same pitch and orientation as the array. Irradiance sensors should be cleaned to remove dirt and bird droppings.

Manufacturer-Specific Inverter Inspection

Each inverter manufacturer will have specific requirements for inspection, testing, services, and documentation to meet its warranty obligations. Typical requirements for inverter inspections include:

- Record and validate all voltages and production values from the human-machine interface (HMI) display.
- Record last logged system error.
- Clean filters.
- Clean the inside of the cabinet.
- Test fans for proper operation.

- Check fuses.
- Check torque on terminations.
- Check gasket seal.
- Confirm warning labels are in place.
- Look for discoloration from excessive heat buildup.
- Check integrity of lightning arrestors.
- Check continuity of system ground and equipment grounding.
- Check mechanical connection of the inverter to the wall or ground.
- Check internal disconnect operation.
- Verify that current software is installed.
- Contact installer and/or manufacturer about any issues found.
- Document findings for all work performed.

Manufacturer-Specific Tracker Inspection

Tracker manufacturers will have specific requirements for inspections, testing, service, and documentation to meet their warranty obligations. Typical maintenance or startup requirements for tracker systems include:

- Lubricate tracker by inserting grease with grease gun into appropriate grease caps per manufacturer maintenance recommendation.
- Check voltages inside the controller box.
- Use a digital level to check the calibration and positioning of the inclinometers.
- Check array for signs of parts hitting or rubbing other parts.
- Remove vegetation that is near the drive shaft or moving components.
- Check wind-stow operation.

Use appropriate (volt, ohm, dc clamp-on) meters to test:

- continuity of the equipment grounding at the inverter, combiner boxes, and disconnects;
- continuity of all system fuses at the combiner boxes, disconnects, and inside the inverter(s);
- open-circuit voltage (V_{oc}) of all strings with the inverter off; and
- maximum power current (I_{mp}) of all strings with the inverter on and at specified or recorded levels of power.

Additional testing (used when problems are identified or required by contract terms) may include:

- thermal images of combiner boxes (opened and closed), disconnects, inverters (external and internal at a specified operating point for a specified period of time), and modules;
- short circuit (I_{sc}) testing of strings;
- current-voltage (IV) curve testing of strings;
- insulation resistance tests (also known as “megger” tests) of conductors at specified voltage; and
- comparison of a weather-corrected performance calculation of expected output to actual output of the system.

Manufacturer-Specific Data Acquisition System Inspection

Data acquisition system (DAS) manufacturers will have specific requirements for inspections, testing, service, and documentation to meet their warranty obligations. Typical maintenance or startup requirements for DASs include:

- taking voltage readings of power supplies,
- validating current transducer readings by comparing to calibrated equipment, and
- validating sensor reading by comparing to calibrated equipment.

To confirm proper functionality of the DAS, the values measured by the DAS must be verified against values from devices with traceable calibration records. Comparing the irradiance, temperature, and power measurements recorded by the DAS to values obtained from calibrated instruments will help identify sensor calibration issues that could result in the DAS data being incorrect.

The PV industry as a whole is getting better at DAS installation and documentation, but it is still typical for DAS plans to be omitted or insufficiently detailed. As a result of such an omission, plan checkers often do not check for errors in the DAS design and inspectors have nothing to compare the as-built with for compliance . If the DAS will be tied into the building information technology system, O&M personnel should be aware that building networking upgrades or routine maintenance can cause connectivity issues.

GENERAL ISOLATION PROCEDURES

Energized Components

Some testing and maintenance activities may require the system to be energized while workers are working on or near the equipment—string current testing is one example. Another common testing practice discussed in Megohmmeter Testing (megger testing) is to use an insulation resistance meter to induce voltage to wiring or other components in an effort to identify signs of damage to insulation or resistance/leakage from other sources such as loose connections.

OSHA provides guidance for what must be done in order to work safely on energized systems:

- Only qualified employees can work on electric circuits or equipment that has not been de-energized using LOTO procedures.
- Qualified employees must be able to work safely on energized circuits.
- The qualified employee must be familiar with the proper use of special precautionary techniques, PPE, insulating and shielding materials, and insulated tools.
- Employees working in areas where there are potential electrical hazards must be provided with and use electrical protective equipment that is appropriate for the specific parts of the body to be protected and for the work to be performed.

Inverter Pad Equipment

Use the following procedures for disconnecting a single inverter from the grid:

- If applicable, follow the inverter manufacturer guidelines for a controlled shutdown using the HMI keypad to navigate and select a shutdown.
- If the inverter has an on/off switch, turn it to off.
- Turn the ac disconnect switch on the inverter off.
- Turn the dc disconnect switch on the inverter off.
- Turn any remaining external disconnect switches connected to the inverter off.
- Install lockout devices on all disconnects, locking them in the open or off position.
- Repeat for all inverters and switches to completely isolate the entire PV system from the grid and the inverters from the PV power source.

Transformer Isolation

Use the following procedures for transformer shutdown:

- For inverters connected to the transformer, turn the on/off switch to off.
- Turn the ac disconnect off for the inverters connected to the tranformer.
- Turn the dc disconnect off for the inverters connected to the transformer.
- Install lockout devices on the disconnects.
- Turn off the transformer switch, which is either a dedicated stand-alone switch or is located in the switchgear.
- Install a lockout device on the transformer switch.
- Repeat for all transformers to completely isolate them from the switchgear.

FAILURE RESPONSE

Emergency Shutdown

In an emergency situation:

- If the inverters have Emergency Stop buttons, push them in on each inverter.
- If the inverter has an on/off switch, turn it to the off position (this may require a key). Each inverter should be manually turned to the off position. This will immediately open the internal ac and dc contactors (if present) inside the inverter.

Note that some inverters do not have an on/off switch or an Emergency Stop button. For these inverters, it will be necessary to turn the systems off using the disconnect switches attached to or located near the inverters. Do not open switches that are specifically labeled "Do not disconnect under load" until a load-break switch has been opened and current flow is stopped. Generally, the first available upstream load-break ac switch or circuit breaker is safer to operate first (before the dc switch), because the inverter instantly shuts down the transistor bridge when ac voltage is removed. Once the system is off, the remaining switches can be opened and the system can be locked out until the fault condition is repaired or it is safe to turn it back on.

Isolation Procedure—Inverter Pad Equipment

To isolate the inverter pad safely:

- Shut the inverters off through a controlled shutdown.
- Turn off all dc and ac disconnects that feed the pad. Follow the procedure in the LOTO section for opening electrical disconnects.
- Use LOTO procedures to ensure the system remains off.
- Always wear appropriate PPE and test for voltages with a properly rated meter to confirm the system is completely isolated.

Isolation Procedure—Field Combiner Box

To isolate field combiner boxes:

- Turn off the inverters as described above.
- Operate the switch of the combiner (if applicable) by turning the handle to the off position.
- Use a dc clamp on the meter to confirm there is no current passing through the ungrounded conductors in the combiner box, and then open all of the fuses.
- If further isolation of the box is needed, use the string diagrams to locate the homeruns (end connectors of the PV strings).
- Use a clamp-on dc current meter to confirm that the homerun does not have any current passing through it, and then disconnect the string by opening the homerun positive and negative connectors and putting caps on the source circuit connectors.
- Go back to the combiner box and use a voltmeter to confirm that each string has been successfully disconnected.

Isolation Procedure—Modules and String Wiring

After turning off the inverter, switches, and combiner boxes and isolating the combiner boxes from the array, disconnect individual modules from the string:

- Before disconnecting any string, use a dc clamp-on meter to confirm there is no current passing through the string.
- Use the appropriate connector unlocking tool to disengage the module connector.
- Repeat for each module to be isolated from the system.
- If modules are removed from a system, even temporarily, technicians must ensure that the equipment grounding system remains intact for the remaining modules.

INVERTER TROUBLESHOOTING AND SERVICE

There is an understandable focus on maximizing ROI and system production. System uptime and availability is a key objective of O&M. Inverters that are offline can have a dramatic negative impact on the ROI of a PV system. Inverter failure rates are important to ROI, but even more important than how often an inverter goes offline is how quickly it can be placed back into service. The type of inverter fault often dictates how quickly it can be placed back into service. Inverters with known failure modes need a failure response procedure. This may include stocking critical parts that have long supply lead times so that the system is not left offline because of a lack of spare parts.

Inverter Troubleshooting

When an inverter goes offline, technicians must determine why and correct the error as quickly as possible. They can check the HMI for reported errors, and then follow the actions noted in the table below.

Common Reported Inverter Errors

Inverter Error	Action
Dc undervoltage	Steps to diagnosing underperforming systems
Dc overvoltage	V_{oc} string testing
Dc ground fault	Ground fault detection procedure
Gating fault	Check connections Contact manufacturer
Ac undervoltage	Confirm all breakers are on Check ac voltage with voltmeter If within range, perform a manual restart If outside of range, contact utility
Ac overvoltage	Check ac voltage with voltmeter If within range, perform a manual restart If outside of range, contact utility
Low power	System is likely just shutting down because of lack of sun; if it is sunny, perform steps to diagnose underperforming systems
Over temperature—fan not operating	Check power supply to fan—if good, replace fan; if bad, replace power supply
Over temperature—fan is operating	Check to confirm sensor readings—if bad, replace sensor; if good, investigate further
Over temperature—fan is operating, sensors are accurate	Check intake and exhaust filters for excessive buildup, and clean or replace if necessary
Software fault	Contact manufacturer

Some inverter faults will clear automatically when the fault condition returns to normal, but some fault conditions require a manual reset of the inverter. The ground fault fuse and even ac fuses can be non-standard items that are difficult to purchase. Keep replacements on hand, especially if there are multiple inverters of the same size on site or in the portfolio. Having qualified technicians available and properly equipped with common replacement parts helps maximize system uptime.

Inverter Service Procedures

Some inverter service actions require that the system be shut down for safe inspection. Always begin with an examination of the equipment as described in the ROUTINE SCHEDULED PREVENTIVE MAINTENANCE chapter, and further inspect subassemblies, wiring harnesses, contacts, and major components.

The following sample inverter service checklist applies to larger inverters (not residential scale) and is not intended to be complete for all models from all manufacturers:

- Check insulated gate bi-polar transistors and inverter boards for discoloration. Use inspection mirror if necessary.
- Check input dc and output ac capacitors for signs of damage from overheating.
- Record all voltage and current readings from the front display panel.
- Check appearance/cleanliness of the cabinet, ventilation system, and insulated surfaces.
- Check for corrosion/overheating on terminals and cables.
- Torque terminals, connectors, and bolts as needed.
- Record ambient weather conditions, including the temperature and whether the day is cloudy or sunny.
- Check the appearance of both the ac and dc surge suppressors for damage or burn marks.
- Check the operation of all safety devices (emergency stop devices, door switches, ground fault detector interrupter).
- Inspect (clean or replace) air filter elements.
- Correct any detected deficiencies.
- Complete maintenance schedule card.
- Complete written inspection report.
- If manufacturer-trained personnel are available on-site, install and perform any recommended engineering field modifications, including software upgrades.

DIAGNOSING AND TESTING FOR LOW POWER PRODUCTION

Low power production also impacts ROI, and O&M personnel need effective strategies for identifying and correcting problems quickly. System operators or owners may become aware of a PV installation's underperformance through one of the following means:

- a predefined DAS alert, which may be weather-related, a result of comparison with other systems in the portfolio, or a result of comparison with other monitored parts of the system at a site with multiple inverters;
- a manual review of the DAS data through online portal that indicates performance anomalies;
- a comparison of present performance with performance test results from previous maintenance visits; and
- customer or external entity reports of a potential problem, often because of an unexpected increase in a monthly bill.

Diagnostic Overview

Once the underperformance is confirmed, personnel must determine what is causing it. Steps to diagnosing power production deficiencies include:

- During routine maintenance and when diagnosing an underperforming system, the first and most important components to check are the fuses. Fuses generally must be removed from their holders to determine whether they have blown.
- Perform a system performance data review using the DAS or a program such as the PVWatts calculator (NREL, 2012) to calculate the expected system output based on weather conditions and system size to compare actual to modeled systems production.
- Dispatch a field technician to the site to do the following:
  - o Check that on-site performance meters have similar values. Often systems will have revenue grade performance monitoring that can be compared against the inverter display totals.
  - o If there is a difference in the values, then ideally the technician can log into the DAS system (when available) to investigate.
    - A phase that has a different output than the others could be the result of a bad current transformer (CT) or a blown fuse in the CT circuit (i.e., an instrumentation problem).
  - o If there is no difference in recorded values, then use the inverter operator display/interface (if applicable) to identify the inverter error log. See inverter diagnostics for errors that may have caused the inverter to perform at less than 100% power.
  - o Verify that the array maximum power point voltage is in the maximum power point tracking window of the inverter, using an IV curve tracer on a sample string or group of strings. Modules will degrade over time and an array that begins service at the lower end of the inverter maximum power voltage window may degrade until its maximum power voltage no longer falls within this range, further compounding the effects of module degradation.

- Look for external causes of the production drop, such as unexpected shade on the array. Vegetation growth is the most common form of shading, but it is not unusual to find a satellite dish or other object shading the array that was not present when the system was built. Take photographs of the installation during commissioning and keep a visual record of any noticeable differences during maintenance visits.
- Perform general system checks as necessary to identify problems:
    - Check all fuses at the inverter and work out to the combiner boxes.
    - Perform V_{oc} string testing.
    - Perform I_{mp} string testing.
    - Validate weather sensors.
    - Look for soiling. If soiling might be the problem, test an individual string (V_{oc}, I_{mp}, IV curve) and then clean the string and retest.
    - Perform IV curve tracing.
    - Take infrared (IR) images of the PV cells.

Diagnostic Testing

O&M personnel can use a number of diagnostic procedures to determine the cause(s) of power deficiencies in a PV installation. The following sections describe these tests in detail.

Infrared (IR) Image Procedure

This procedure describes how to properly perform field diagnostics of a PV installation using an IR camera to detect abnormal heat signatures. Topics include correct camera settings and proper conditions for field inspection.

Test conditions

- IR imaging should be completed with the system operating at peak levels if possible.
- Do not open or work in electrical boxes, particularly those with NEMA 4 rating, during rainy or wet conditions.

Tools include:

- IR Camera, such as Fluke Ti10, Fluke Ti32, FLIR i40, or FLIR i7; and
- clamp-on ammeter.

Safety considerations

- Ensure all OSHA and environmental health and safety requirements are met, especially if working on angled roofs and/or at heights greater than six feet.
- Safety precautions should also be taken when working near active high voltage systems or near surfaces that may be very hot to the touch.
- Contact local health, security, safety, and environment personnel for questions and access to pertinent documentation.

IR imaging procedure

- Before starting the IR scan, verify that the PV array is operating, because temperature differences in modules are not apparent when the system is not operational.
  - o Check inverter display for instantaneous kilowatt output.
  - o Check current on each string in combiner box to ensure that it is operational.
  - o If the inverter or any of the strings are not operational, these must be corrected before the test can be conducted.

IR camera settings

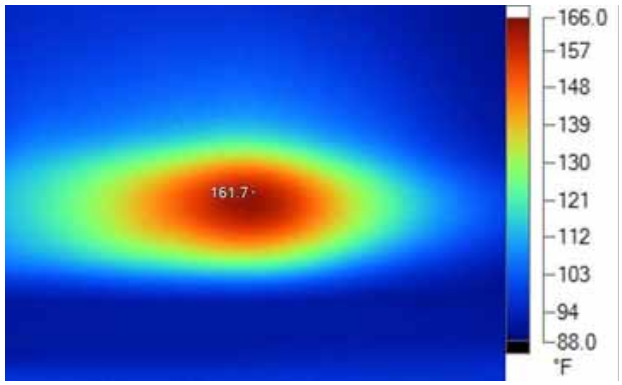
- Set the IR camera to "auto-scaling" rather than manual scaling. This will allow for automatic adjustment of the temperature scale.
- Set emissivity value to 0.95 (usually the camera default). The IR camera does not capture shiny surfaces such as polished metals well due to their low emissivity value. However, for most active components on a solar module such as cells, J-Box, and cables, a value of 0.95 will be sufficient.
- Set temperature units to Celsius.
- Set color palette to Iron or Rainbow. "A thermal imager interprets IR radiated or reflected heat by assigning a visible graduated color or gray scale to a radiated portrait of the scene. The color palette displays hot spots as white with diminishing temperatures through red-orange-yellow-green-blue-indigo-violet to black being cold" (Fluke Corporation, 2006, 2008).

IR inspection

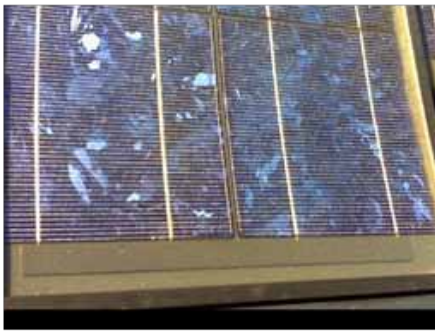
- When sunlight is present and camera settings are properly set, point the lens at the object of interest. In the case of solar modules in operation, looking through the glass onto the active cells is the most common inspection technique.
- Ensure that the picture is focused, either manually or automatically. For best results, position the camera as close to the module as possible without shading it or creating a reflection in the glass surface. If possible, the distance between the camera and the surface to be measured should not exceed three meters or 10 feet. This will depend on the camera's minimum focal distance and other specifications. Some temperature differences will not be picked up if the camera is too far away from the module.
- For best results, position the camera as perpendicular as possible to the object being measured. Hot spots will be easier to see if the image is taken perpendicular to the module surface. Image quality will degrade at camera angles other than normal (i.e. perpendicular) incidence.
- Care should be taken to avoid shading any part of the module while capturing images.
- Record module serial number, time, date, picture number, and module location in the array for all issues.

Sample Images

Junction boxes on back surface of a PV module

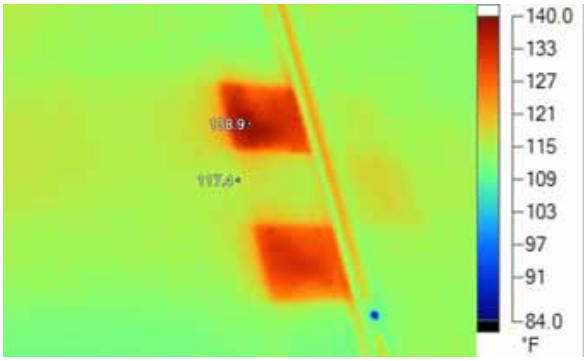


IR Image



Visible light image

Cells in a module



IR Image

Visible Light Image

Megohmmeter Testing

Megohmmeter or "megger" testing is a valuable way to identify weakened conductor insulation and loose wiring connections. These tests are often used in system acceptance and commissioning procedures but not often used in general maintenance unless a thorough troubleshooting of a fault condition is needed. The insulation resistance tester (IRT) applies a voltage to the circuit under test and measures return current to determine the insulation resistance and integrity. IRTs have various test voltage settings, such as 50 V, 100 V, 250 V, 500 V, and 1,000 V. Generally, the higher voltage settings are better for detecting high impedance shorts in the wiring than lower voltage settings. However, some newer low voltage equipment has sophisticated filtering that enables effective measurements even on circuits with PV modules. All 600 V-rated wire and PV modules should be capable of being tested at 1,000 V_{dc}, because they are factory proof tested at twice the maximum rated voltage plus 1,000 V—this adds up to 2,200 V for 600 V cable and PV modules. This test is short-term and will not damage the wire or module insulation.

To test specific products, including strings of modules, it is best to confirm that the testing (high voltage) will not void the warranties of those materials. It is best to get written permission for testing procedures from the module manufacturer if they do not already have approved megohmmeter testing guidelines. Some manufacturers explicitly disallow megohmmeter testing on their modules. Although it is true that some products may not allow this testing, the most common location of ground faults in PV systems is in the module wiring and modules

Testing using the 500 V_{dc} setting may be appropriate for some modules. Lower voltages are often necessary when the system includes surge protection devices within the combiner boxes. Insulation testers are now available with 50 V_{dc} settings that will not damage the surge protectors. If these are used it is important to ensure that they have filtering capable of compensating for the array capacitance. The added benefit of a low voltage insulation test is that it can detect problems with surge protectors. Leaking surge protectors are a common fault of older PV systems.

Test conditions

- Do not open or work in electrical boxes, particularly those with NEMA 4 rating, in wet conditions.

Tools include:

- IRT megohmmeter;
- PPE rated for the appropriate voltages;
- screwdriver or combiner box key, if applicable;
- dc clamp-on meter;
- dc voltmeter;
- electrical tape;
- system drawings—string wiring diagram;
- warning signs: "High Voltage—Testing in progress—Stay clear of photovoltaic array!"; and
- recording device (pen and paper, laptop or tablet preferred).

Safety considerations include:

- shock hazard, live voltages present;
- fall hazard, combiner boxes are often elevated;
- need for proper PPE for electrical voltage testing;
- recognition that normally de-energized circuits may be energized in fault conditions; and
- requirement for two qualified people trained in CPR.

IRT testing procedure

- Turn system off at the inverter.
- Post "High Voltage," Testing in progress," "Stay clear of photovoltaic array!" signs around all entry points to array.
- Use LOTO procedures.
- Record test conditions including ambient temperature and irradiance.
- Open disconnect switch on combiner box, if applicable. If there is no switch at the combiner box, open the applicable disconnect or fuse at the inverter to isolate the combiner box circuit.
- Isolate the output circuit grounded conductor (negative in a negative grounded system, positive in a positive grounded system) by removing the cable from its termination.
- Remove any surge protection devices from circuits being tested (if testing at more than 50 V_{dc}).

- Visually inspect box for signs of damage, including:
    - heat discoloration,
    - corrosion,
    - water intrusion, and
    - conductors rubbing against metal in enclosure or other insulation damage.
- Use dc current meter to confirm there is no current present in the combiner box.
- Open all fuse holders.
- Use ohmmeter to verify continuity of the box enclosure to ground. If enclosure is not metal, verify ground wire connection to ground.
- Test V_{oc} of all strings to confirm proper polarity and voltage of each string.

FOR POSITIVELY GROUNDED SYSTEMS:

First, test all strings in the box simultaneously:

- Set megohmmeter on a sturdy surface. Attach red lead to red terminal on tester. Attach black lead to black terminal on tester.
- Attach the red (positive) lead from megohmmeter to the ground busbar in the combiner using an alligator clip. Attach black (negative) lead from megohmmeter to the positive busbar (unfused side).

If low impedance is detected at the box level, test the individual strings:

- Remove positive string conductors one at a time from the grounded conductor (positive) busbar, capping each with a wire nut before moving to the next. Make sure there is no exposed copper once the wire nut is tight.
- Set megohmmeter on a sturdy surface. Attach red lead to red terminal on tester. Attach black lead to black terminal on tester.
- Attach the red (positive) lead from megohmmeter to the ground busbar in the combiner using an alligator clip. Attach black (negative) lead from megohmmeter to the positive lead of the string.

FOR NEGATIVELY GROUNDED SYSTEMS:

First, test all strings in the box simultaneously:

- Set megohmmeter on a sturdy surface. Attach red lead to red terminal on tester. Attach black lead to black terminal on tester.
- Attach the black (negative) lead from megohmmeter to the ground busbar in the combiner using an alligator clip. Attach the red (positive) lead from megohmmeter to the negative busbar (unfused side).

If low impedance is detected at the box level, test the individual strings:

- Remove negative string conductors one at a time from the grounded conductor busbar, capping each with a wire nut before moving to the next. Make sure there is no exposed copper once the wire nut is tight.
- Set megohmmeter on a sturdy surface. Attach red lead to red terminal on tester. Attach black lead to black terminal on tester.
- Attach the black (negative) lead from megohmmeter to the ground busbar in the combiner using an alligator clip. Attach red (positive) lead from megohmmeter to the negative lead of the string.

FOR UNGROUNDED SYSTEMS:

For ungrounded systems, note there should be two pole switches to completely isolate the positive and negative combiner circuits from the inverter and other combiner boxes, so there should be no need to remove an output circuit cable from its terminal.

First, test all strings in the box simultaneously:

- Open the positive fuse holders only in the combiner box, leaving the negative fuse holders closed in.
- Set megohmmeter on a sturdy surface. Attach red lead to red terminal on tester. Attach black lead to black terminal on tester.
- Attach the black (negative) lead from megohmmeter to the ground busbar in the combiner using an alligator clip. Attach the red (positive) lead from megohmmeter to the negative busbar.

If low impedance is detected at the box level, test the individual strings:

- Open all of the positive and negative fuse holders. The string conductors do not need to be removed from the fuse holders.
- Set megohmmeter on a sturdy surface. Attach red lead to red terminal on tester. Attach black lead to black terminal on tester.
- Attach the black (negative) lead from megohmmeter to the ground busbar in the combiner using an alligator clip. Attach red (positive) lead from megohmmeter to the negative lead of the string, using the array-side screw terminal of the fuseholder.
- After positive leads are tested using the procedure below, repeat the test on the negative leads of the string using the array-side screw terminal of the fuseholder.
- Set meter to the appropriate voltage setting.
- Press and hold the "Test" button for a specific and consistent time period—at least 15 seconds.
- Watch the display of the meter closely during the 15 second tests and look for fluctuations in the readings.
- Record the result after the 15 second interval. Insulation resistance measurements will vary based on system age, moisture, temperature, and the size of the string under test. Because absolute numbers vary based on these and other conditions, typically a string conductor with a value of greater than one to three megaohms is considered passing (Mync & Berdner, 2009). Box level measurements can be lower, as low as 500 kiloohms. Because of the variable conditions stated above, it is important to look for relative differences in the measurements of different boxes.
- Repeat test until all strings are tested.
- If a string fails the test, isolate the conductors from the array and test again.
- Replace or repair all wiring in any failed strings.
- Record all results for future comparison.

Fuse Checks

Fuses blow for a reason. Whenever a blown fuse is found, investigate why the fuse blew. When replacing fuses, it is essential to source the appropriate size, type, and rating. Do not assume that the fuse being replaced was the correct size, type, and rating, because an incorrect rating or size could be the reason the fuse blew. It may be necessary to consult the product manual to ensure the correct fuse is sourced. It is common to come across operating systems with incorrect fuses in place.

Test conditions

- Fuses can be checked under any test conditions.
- Do not open or work in electrical boxes, particularly those with NEMA 4 rating, in wet conditions.

Tools include:

- ohmmeter;
- PPE;
- screwdriver or combiner box key, if applicable;
- fuse puller, if applicable; and
- recording device (pen and paper, laptop or tablet preferred).

Safety considerations

- Fuses should never be replaced or tested while the circuit is energized. Shut the system down prior to servicing fuses.
- Wear proper PPE for electrical voltage testing, at least until no voltage has been verified and the source has been locked out, if applicable.

Fuse testing procedure

- Confirm system is de-energized with a voltmeter.
- Use LOTO procedures.
- Use an ohmmeter to test the continuity of the fuse. It may be possible to get voltage through a fuse that has not completely blown but is about to blow. For this reason, having voltage only on the load side of the fuse is not enough.
- Set ohmmeter on a sturdy surface.
- Remove the fuse to be tested from the fuse holder unless it is clear that no alternative continuity paths can exist that would provide a false reading.
- Use meter and test the fuse by placing a lead on each end of the fuse and listening for the meter to beep confirming continuity.
- If the beep continuity reading is not constant while still holding the leads on each end of the fuse, then look at the ohm settings for a measurement of the resistance. Make sure your fingers are not touching each end of the fuse as this will give a resistance reading for an open fuse that can be confusing.
- Look at the fuse and confirm the size, type, and rating of the fuse.
- If the fuse fails the test or is not the properly rated size or type, replace the fuse with the correct fuse.
- Always test replacement fuses before installing to confirm the fuse was good when it was placed in service.

Best practices

While testing the voltages with the system off and the fuses open, prep the box for current testing. Cut zip ties if needed and make sure the conductors are tight in their terminals and will not come out when the current clamp is placed around them in the next phase of testing.

Test with a two-person team so one can keep the safety equipment on and take readings while the other records the readings. This will allow for efficient testing, because the person taking the readings can enter them directly into a form. In addition, there is the safety advantage of having two people present when working on live equipment.

DC System V_{oc} Checks

Dc voltage checks are done with the system off, but—depending on the system size—voltages of up to 1,000 V_{dc} may be present.

Test conditions

- Ideally, test in stable sunlight of more than 750 watts per square meter (W/m^2). However, stable conditions more than 200 W/m^2 still allow for simple comparisons among strings.
- Do not open or work in electrical boxes, particularly those with NEMA 4 rating, in wet conditions.
- Perform testing at the combiner boxes.

Tools include:

- dc voltmeter;
- PPE;
- irradiance meter;
- temperature sensor;
- screwdriver or combiner box key, if applicable; and
- recording device (pen and paper, laptop or tablet preferred).

Safety considerations include:

- shock hazard, live voltages present;
- fall hazard, combiner boxes are often elevated;
- proper PPE for electrical voltage testing;
- recognition that normally de-energized circuits may be energized in fault conditions; and
- requirement for two qualified people trained in CPR.

Voltage testing procedure

- Turn system off at the inverter.
- Use LOTO procedures.
- Record test conditions including ambient temperature and irradiance.
- Open disconnect switch on combiner box, if applicable.

- Visually inspect box for signs of damage, including:
    - heat discoloration,
    - corrosion,
    - water intrusion, and
    - conductors rubbing against metal in enclosure or other insulation damage.
- Open all fuse holders.
- Attach red lead to red terminal on tester. Attach black lead to black terminal on tester.
- Use ohmmeter to verify continuity of the box enclosure to ground. If enclosure is not metal, verify ground wire connection to ground.
- Use dc clamp-on ammeter to test for current in the equipment grounding conductor. If current is present, stop this procedure and proceed to the Ground Fault Troubleshooting procedure.
- Use voltmeter to test equipment grounding conductor to ground.
    - If voltage is present, find source of problem before placing combiner box back into service.
    - Test ungrounded conductors one at a time by removing them from the bussing. Wear PPE and use insulated tools to remove ungrounded conductors under a fault condition.
- Ideally, use an alligator clip meter cable for the black lead, connect to ground.
- Take the red lead and individually test from the line side of the open fuse holder for the ungrounded conductor.
- Record results.
    - Note voltage and polarity of each string, and if polarity is incorrect, find the source of problem before placing back into service.
    - If reverse polarity is observed, do not just switch it without further investigation to identify the problem. Re-identify and properly label conductors if a switch is made. A change to the as-built plans may also be necessary.
    - All voltages should be within 10% of each other. If one string is the equivalent of the V_{oc} of one module (roughly 30-40 V depending on the module) less than the average and one string is 30-40 V more than than the average, it is a good indication that the stringing is incorrect for both strings.
    - Given the same example of 40 V_{oc}, if one string is 10-20 V less, then there may be an issue with one of the modules, and further investigation may be necessary (such as performing IV curve tracing).
- If I_{mp} testing is going to be carried out in the same combiner box, it is best to prep the box for the I_{mp} testing.
    - Ensure all terminations are properly torqued.
    - Pull on conductors to ensure a large enough loop for the current meter to attach to. If necessary, cut zip ties.
- Close fuse holders.
- Close disconnect.

DC System I_{mp} Checks

The dc I_{mp} tests are completed with the system running. Full operating voltages and current are present in the combiner boxes.

Test conditions

- Ideally, test in full, stable sunlight. Usually, a minimum stable irradiance of 500 W/m^2 will allow for accurate comparisons among strings.
- Do not open or work in electrical boxes, particularly those with NEMA 4 rating, in wet conditions.
- Do the testing at the combiner boxes. The ambient test conditions should be recorded for each combiner box. This includes the ambient temperature and plane of array irradiance. If a calibrated weather station is installed, a time stamp can be used to pull the data from the weather station or handheld tools can be used to record the real time values.

Tools include:

- dc clamp meter;
- PPE;
- irradiance meter;
- temperature sensor;
- wrench or additional combiner box handle;
- screwdriver or combiner box key, if applicable; and
- recording device (pen and paper, laptop or tablet preferred)

Safety considerations include:

- shock hazard, live voltages and current present;
- fall hazard, combiner boxes are often elevated;
- proper PPE for electrical current testing; and
- requirement for two qualified people trained in CPR.

I_{mp} testing procedure

- With system operating, open dc combiner box.
- It may be necessary to use a wrench or other handle type tool to close the combiner box switch (if the system is so equipped) with the door open. Technicians should wear proper PPE.
- Box should be prepped in advance during the voltage testing process.
    - Fuse holders are not meant to be opened under load.
    - The dc combiner boxes may not be designed to be turned off under load—look for warning labels.
- With a two-person team, an electrician wearing the proper PPE places a dc clamp-on meter around each individual string, calling out the numbers to the helper who records the data.

- Close the combiner box lid.
    - If the combiner box lid cannot be closed with the switch closed, turn the inverter off and then open the switch rather than shutting off the switch with the door open. This is usually more efficiently done after all combiner boxes are tested rather than individually.
- Compare the I_{mp} results of strings with identical pitch and orientation and similar test conditions to look for low-performing strings.
    - Low performing strings can be further diagnosed using the steps for diagnosing production issues in the Diagnostic Overview section.

Grounding System Integrity Checks

It is important to verify that the equipment ground is properly installed on all exposed non-current carrying metal parts. That way, the removal of a single piece of equipment—during module replacement, for example—does not impact the integrity of the bonding of the remaining equipment. If removal of any component results in a break in the bond connection, a jumper of suitable ampacity must be used as a temporary connection.

Test conditions

- Tests can be performed in any weather condition.
- Do not open or work in electrical boxes, particularly those with NEMA 4 rating, in wet conditions.

Tools include:

- ohmmeter;
- screwdrivers; and
- keys to open enclosures, if applicable.

Safety considerations include:

- This test presents a fall hazard, because some of the system grounding equipment may be located higher than six feet and will require fall protection per OSHA 1926 Subpart M.

Procedure

- Set ohmmeter to the continuity setting.
- Touch one lead to a metal surface or ground wire.
- Touch the other lead to a nearby metal surface or ground wire.
    - Confirm continuity between the two surfaces by listening for the beep when the leads touch the surfaces at the same time.
- Repeat this process randomly throughout the array and at every combiner box, disconnect, and inverter.

DAS Check

DAS checks are used to validate the existing systems. If any component is not up to specs, it may be quicker and cheaper to replace it with a new component than to attempt alter settings. In some cases, the cheapest and best option may be to establish a policy of replacing equipment such as irradiance sensors at defined intervals rather than spend the time validating the data and then replacing when out of calibration.

Test conditions

- Ideally, test in full, stable sunlight.
- Do not open or work in electrical boxes, particularly those with NEMA 4 rating, in wet conditions.
- Do the testing at the equipment involved, which can be installed throughout the system in combiner boxes, switchgear, transformers, and inverters in the array as well as in separate dedicated DAS enclosures.

Tools include:

- ac/dc voltmeter;
- ohmmeter;
- laptop;
- computer software (DAS/manufacturer-specific);
- computer cables (Ethernet, Crossover, RS232 to USB, RS485 to USB);
- PPE;
- irradiance meter;
- temperature sensor;
- level;
- inclinometer;
- compass;
- screwdrivers/sockets; and
- equipment keys, if applicable.

Safety considerations include:

- shock hazard, live voltages present;
- fall hazard—combiner boxes and meteorological stations are often installed at heights of more than six feet and will require fall protection per OSHA requirements;
- proper PPE for electrical voltage testing;
- normally de-energized circuits may be energized in fault conditions; and
- requirement for two qualified people trained in CPR.

Testing procedure

- Global horizontal irradiance:
    - Ensure location is not shaded.
    - Use level to make sure it is level.
    - Clean with a cloth and mild soap solution if necessary.
    - Log in to DAS program.
    - Place cleaned and recently calibrated handheld sensor in same pitch and orientation.
    - Compare results.
    - If outside of acceptable range, replace sensor, noting serial number of the new sensor for as-built updates.

- Plane of array irradiance:
  - Ensure location is not shaded.
  - Use inclinometer and compass to ensure it is in the same pitch and orientation as the array.
  - Clean with a cloth and mild soap solution if necessary.
  - Log in to DAS program.
  - Place cleaned and recently calibrated handheld sensor in same pitch and orientation.
  - Compare results.
  - If outside of acceptable range, replace sensor, noting the serial number of the new sensor for as-built updates.
- Ambient temperature sensor:
  - Log in to DAS program.
  - Take reading from handheld temperature sensor.
  - Compare results.
  - If outside of acceptable range, replace sensor, noting the serial number of the new sensor for as-built updates.
- Back of module temperature sensor:
  - Ensure sensor is correctly adhered to the back of a module in the middle of a cell in the middle of the module.
  - Log in to DAS program.
  - Take reading from handheld temperature sensor.
  - Compare results.
  - If outside of acceptable range, replace sensor, noting the serial number of new sensor for as-built updates.
    - Rather than risk damaging the module, leave the sensor in place and install the new sensor in the middle of the next closest cell.
- Anemometer:
  - Log in to DAS Program.
  - Hold the anemometer and confirm it is reading 0 MPH.
  - Turn to confirm it is moving.
  - If further testing is needed, use a handheld anemometer and compare the results at a consistent windspeed greater than three meters per second.
  - If outside of acceptable range, replace sensor, noting the serial number of new sensor for as-built updates.
- Current transducers:
  - Log in to DAS Program.
  - Basic test is to compare the current readings to the inverter display current readings.
  - Revenue grade validating involves using a calibrated current meter and placing it around the same conductors with the system running.
    - Proper PPE must be worn when testing live circuits.
  - Compare results.
  - If outside of acceptable range, replace sensor, noting the serial number of new sensor for as-built updates.

- Voltage reference:
  - Log in to DAS program.
  - Check fuses with ohmmeter.
  - Use calibrated voltmeter to test circuits.
    - Proper PPE must be worn when testing live circuits.
  - Compare results.
  - If any difference is noted, switch to other phases.
    - Meter could be bad.
    - Reference phase could be mislabeled.
- Revenue meter:
  - Log in to DAS program.
  - Navigate program to compare programmed CT ratio to the ratio listed on the CTs.
  - Look at power factor of all three phases to confirm it is close to one with the system operating.
    - Note that power factor may be low at startup or in low light conditions of less than 250 W/m^2.
  - Confirm good phase rotation with system running.
  - Compare revenue grade data with inverter data, noting differences.
- Inverter direct:
  - Log in to DAS program.
  - Confirm system is checking in accurately.
  - Look at system history to confirm data is not intermittent.
    - Intermittent data from inverters can be the result of noise induced by the inverter.
      - Check that the recommended shielded cable is used for communication wiring.
      - Check route of communication wiring to ensure it is away from voltage carrying conductors.
      - Confirm shield is only landed in one spot; best to do this at the DAS enclosure.
      - Confirm appropriate resistor or termination is installed in the last inverter in the chain (if required).
- Combiner box level monitoring:
  - Log in to DAS program.
  - Confirm that all boxes are visible.
  - Compare results to I_{mp} string test results.
- Module level monitoring:
  - Log in to DAS program.
  - Confirm communication to all devices.
  - Shade individual modules to confirm module mapping is accurate.

Ground Fault Troubleshooting

Ground faults can be difficult to troubleshoot, depending on the severity and location of the fault. However, steps can be taken to efficiently troubleshoot ground faults in a PV system.

Test conditions

- Testing can be done under any conditions with enough light to produce voltage. However, some fault conditions only occur when the system is wet or is moved to a particular angle, and may be difficult to troubleshoot without replicating those conditions.

Tools include:

- dc voltmeter;
- ohmmeter;
- replacement fuses;
- jumper wire USE-2 or PV Wire with male and female connectors compatible with the system;
- megohmmeter;
- PPE;
- screwdriver or combiner box key, if applicable;
- electrical tape;
- system drawings—string wiring diagram; and
- recording device (pen and paper, laptop preferred).

Safety considerations include:

- shock hazard, live voltages present;
- normally un-energized components may become energized under fault condition;
- fall hazard—combiner boxes and meteorological stations are often installed at heights of more than six feet and will require fall protection per OSHA requirements;
- proper PPE for electrical voltage testing;
- normally de-energized circuits may be energized in fault conditions; and
- requirement for two qualified people trained in CPR.

Test procedure—small residential-scale inverters

- Turn inverter off at the on/off switch, if applicable.
- Turn off the dc and ac disconnects (may be the same switch).
- Remove and test the ground fault fuse continuity with an ohmmeter.
    - o If the fuse is good, may not have a ground fault.
    - o Verify by testing voltages to ground with the fuse removed. If within specifications, replace fuse and restart meter.

- If the fuse fails continuity test, there may be a ground fault.
  - Verify it is the correct rating type and size fuse.
  - In most small inverters, the fuse is the path to ground. When the fuse is removed from the system, the normally grounded conductor is no longer grounded.
  - If the ends of the circuit are isolated, neither the ungrounded nor grounded strings should have a well-defined open circuit voltage when tested from the conductor to ground.
  - If a well-defined voltage is present, there may be a fault.
    - Small inverters usually have four or fewer inputs, so isolate the string with the fault by removing the fuses from the combiner box.
    - With the fuses removed, test for voltage from the line side of the fuse terminals to ground.
    - If voltage is present on all of the terminals to ground, isolate the normally grounded conductors by removing them from the bussing.
    - Repeat until the string with the fault is found.
- Take the isolated string with the fault and record the voltage from the normally grounded conductor to ground and from the normally ungrounded conductor to ground.
  - If the voltage is equal to the full open circuit voltage of a string, then the fault is likely at the normally grounded end of the string.
  - If the voltage is a different value, then the fault is likely somewhere in the middle of the array or possibly in a module.
    - Determine the location of the fault by adding the V_{oc} of a single module one after another until it adds up to the voltage of the fault. For example, consider 10 modules in a string with a V_{oc} of 50 V_{dc} each, with module one connected to the ungrounded homerun cable and module 10 connected to the grounded homerun cable. When testing at the combiner box from the line side of the ungrounded fuse holder to ground and the result is 100 V_{dc} and testing from the ungrounded conductor to ground and the result is 400 V_{dc}, then the fault is somewhere between the second and third module in the string. Given the same wiring as above but a reading of 0 V_{dc} from the ungrounded side and 500 V_{dc} from the grounded side, the fault is in the ungrounded homerun.
- Given the above scenario, it would be wise to use a megohmmeter on all of the conductors in the conduit to make sure that the fault is isolated to the one homerun conductor.

Test procedure—central type inverters

- Turn inverter off at the on/off switch, if applicable.
- Turn off the ac and dc disconnects connected to the inverter.
- Remove and test the ground fault fuse continuity with an ohmmeter.
  - If the fuse is good, there may not be a ground fault.
  - Verify by testing voltages to ground with the fuse removed. If good, replace fuse.
  - If the fuse fails the continuity test, there may be a ground fault.
  - Verify it is the correct rating type and size fuse.

- For central inverters, the only fuse allowed in the grounded conductor is the ground fault interrupter fuse with an accompanying label, so removing the fuse will unground the grounded conductor.
    - Remove conductors one at a time, test the voltage to ground, and then put a wire nut or electrical tape around the end of the conductor.
    - Repeat until the string with the fault is identified. (Note: If the combiner box with the fault was not found, the next step is to use a megohmmeter to test the homerun wires from the combiner box back towards the inverter. It is possible to have a fault in the homerun wire from the combiner box to the inverter.)
- Take the isolated string with the fault and record the voltage from the normally grounded conductor to ground and from the normally ungrounded conductor to ground.
    - If the voltage is equal to the full open circuit voltage of a string, then the fault is likely at the normally grounded end of the circuit.
    - If the voltage is a different value, then the fault is likely somewhere in the middle of the array or possibly within a module.
        - Determine the location of the fault by adding the V_{oc} of one module after another until it adds up to the voltage of the fault. For example, consider 10 modules in a string, with each module having a V_{oc} of 50 V_{dc}. Module one is normally the ungrounded homerun and module 10 is normally the grounded homerun. If a test at the combiner box from the line side of the ungrounded fuse holder to ground results in 100 V_{dc}, and the test from the ungrounded conductor to ground results in 400 V_{dc}, then the fault is somewhere between the second and third module in the string. Given the same wiring as above but a reading of 0 V_{dc} from the ungrounded side and 500 V_{dc} from the grounded side, the fault is in the ungrounded homerun.
- Given the above scenario, it would be wise to use a megohmmeter on all of the conductors in the conduit to make sure that the fault is isolated to the one homerun conductor.

Array Washing Procedure

Depending on the site conditions, an annual or even quarterly cleaning may pay for itself in gained production. Some sites have more accumulation of dirt and other buildup than other sites. Depending on the tilt of the array and amount of seasonal rainfall, the soiling can have a dramatic impact on the overall production of the system. Most module manufacturers have specific guidelines about how not to clean modules, such as not using high pressure water, not using harmful chemicals, and even not using cold water when the module glass temperature is hot or using hot water to clean cold modules. Thermal shock from the difference in temperature between the glass surface temperature and the water temperature can result in fracturing or breaking of the glass.

Safety Considerations

- Wear rubber sole shoes with good traction to prevent slips and falls.
- Never walk on the modules. Use non-conductive extended reach broom and hose handles to reach modules
- A lift may be needed to access the array. Follow aerial lift safety procedures, including wearing a harness if required.

Before Washing Modules

- Walk the site to confirm that there are no broken modules (shattered glass). Never spray broken modules with water. Perform a safety evaluation of the site looking for safety hazards such as trip hazards or areas that will become excessively slippery when wet.
- Plan for water runoff. If the site has a storm water prevention plan in place, determine how the used water will be collected and disposed of. If harmful chemicals are not used during the cleaning process, drain guards can be used to filter out sediments.
- Be aware of trip hazards introduced by having hoses spread throughout the property, cone off area if needed.
- Determine whether the module cover glass is too hot and will be damaged by coming into contact with cool water. Depending on the local climate and time of year, it may be best to limit washing activities to the morning or evening hours.
- Identify the water source to be used. Ideally, there will be a source of water near the array. If not, it may be necessary to bring in water from an outside source, which will involve a tank or water truck.
- Determine the best method of getting water to the modules. Typically, a ¾-inch garden hose is used to connect to a spigot near the array.
- Set up hoses and tools.
- If required, block or install drain guards for filtration or water capture purposes.
- Take a baseline production reading of the system, noting both kilowatt-hour (kWh) output of each of the inverters and weather conditions including temperature and irradiance.

Washing Modules

- De-ionized water is preferred to prevent spotting and calcium buildup.
- Normal water pressure of 50 to 70 pounds per square inch is recommended; do not use high pressure washers.
- If high pressure washers are necessary, hold the pressure source far enough away from the modules to prevent damage. As a rule of thumb, if the stream is too strong to comfortably hold one's hand in, it is too much pressure for the modules.
- Spray the modules with water.
- Use a soft-bristled brush to get stubborn dirt off.
- If needed, use a non-damaging soap.
- Use extensions with tools to be able to reach extended distances.
- If needed, squeegee modules dry.

After Washing Modules

- After the system returns to steady-state temperature (i.e., there is no remaining impact from the cooling effect of wash water), take another production reading of the system, noting both kWh output of each of the inverters and weather conditions including temperature and irradiance.
- Clean up tools.
- Remove any drain guards or blocks.

- Record the washing in the maintenance log.
- Compare production of the clean system to the previous production values.

Vegetation Management

Vegetation management is particularly important in ground mount systems, but is a concern for all PV systems. Vegetation can grow into and cause problems with trackers, can cause problems with array wiring, and can cause shading, which will definitely impact production but could also cause damage to an operating system. Vegetation should also be controlled around the inverter pad and other areas where electrical equipment is present. Note: PV arrays are often home to snakes, bees, and venomous animals of all kinds. Wear protective clothing and be alert for possible encounters.

Safety Considerations

- Wear rubber soled shoes with good traction to prevent slips and falls.
- Wear PPE to prevent bites and stings from insects, snakes, and vermin.

Vegetation Management

- Mowing or weed trimming vegetation around a ground mount can lead to problems if the mowing or weed trimming kicks up debris that can break the glass or cause general soiling that results in underperformance.
- Poisoning weeds can lead to environmental and health problems.
- Permanent abatement at the time of installation is the ideal way to deal with vegetation management.
- During inspections, note the amount of vegetation growth and document it through pictures.
- Work with the site owners to come up with a specific vegetation management plan that involves carefully removing or cutting back vegetation that is currently shading or will eventually grow to shade parts of the array.

System Warranties

It is important to know and understand the warranty requirements of the specific products used in a PV system. Not all warranties are created equal. Warranty requirements not followed, including documenting regularly conducted preventive maintenance, can result in a voided warranty. Typical warranty requirements are strict regarding the tasks that must be performed. However, the tasks are often simple and serve to protect the products and ensure greater long-term reliability.

CONCLUSIONS

As the number of U.S. PV installations grows, the industry will increasingly focus on O&M. PV systems have multi-decade lifetimes, and regular O&M helps optimize an installation's ROI over its life. There are currently three working groups focused on this issue, and they will develop a more comprehensive O&M approach in the next few years. In the meantime, this report serves as an introduction to O&M for PV installations.

The conclusions of this introductory report include:

- To maintain quality control and safety standards, it is important that only qualified personnel work on PV installations. It is not always easy, however, to identify qualified personnel. The authors suggest skill and knowledge guidelines for PV technicians in the Qualified Personnel section of the INTRODUCTION chapter.
- Safety is a serious concern when servicing PV installations. Early PV systems often had maximum system voltages less than 50 V_{dc}, but 600 V_{dc} systems are now common, and 1,000 V_{dc} systems are allowed by code in commercial and large-scale installations. Safety considerations require that qualified personnel use properly rated equipment and be trained for servicing the higher voltage systems.
- Qualified personnel should always work in teams of two people when working on live equipment. In addition, on a given jobsite, there should always be at least two qualified persons trained in CPR.
- Not all installations have appropriate signage, and qualified persons must be trained to recognize potential hazards with or without signage present.
- System uptime and availability is a key objective of O&M. Inverters that are offline can have a dramatic negative impact on the ROI of a PV system. Inverter failure rates are important to ROI, but even more important than how often an inverter goes offline is how quickly it can be placed back into service.
- Low power production also impacts ROI, and O&M personnel need effective strategies for identifying and correcting problems quickly. One specific recommendation is to stock critical parts that have long supply lead times.

ACRONYMS

A	amperes (either ac or dc current)
ac	alternating current or voltage
BOS	balance of system
CFR	Code of Federal Regulations
CPR	cardiopulmonary resuscitation
CT	current transformer
DAS	data acquisition system
dc	direct current or voltage
HMI	human-machine interface
I_{mp}	current at the maximum power
IR	infrared light wavelengths
IRT	insulation resistance tester
I_{sc}	short circuit current
IV	current-voltage designation for PV characteristics
kWh	kilowatt-hour
LOTO	lockout/tagout
NEC	*National Electrical Code®*
OSHA	Occupational Safety and Health Administration
PPE	personal protective equipment
PV	photovoltaic
ROI	return on investment
Solar ABCs	Solar America Board for Codes and Standards
UL	Underwriters Laboratories
V	volt
V_{oc}	open-circuit voltage
W/m^2	watts per square meter

GLOSSARY

balance of system—in a renewable energy system, all components other than the mechanism used to harvest the resource (such as photovoltaic panels or a wind turbine). Balance-of-system costs can include design, land, site preparation, system installation, support structures, power conditioning, operations and maintenance, and storage.

lockout/tagout—safety procedure used to ensure equipment is properly de-energized and, just as importantly, not re-energized until the technician that applied the lock deems it reasonably safe to do so.

megger testing—testing method that uses an insulation resistance meter to induce voltage to wiring or other components in an effort to identify signs of damage to insulation or resistance/leakage from other sources such as loose connections.

PV module connector types—PV modules usually come standard with polarized positive and negative connectors. The connectors are terminations installed by the module manufacturer at the ends of the wires used to couple modules together or in the field to connect the homerun wire back to a combiner box. The connector on the homerun wire needs to be compatible with the connector installed by the module manufacturer. Multi-Contact, Tyco, Amphenol, Wieland, and Radox are five different manufacturers that make different connectors specifically for PV modules.

National Electrical Code—specifically NFPA 70, which is published by the National Fire Protection Association, and is adopted in all 50 states. It is referred to commonly as the *NEC*, and is the benchmark for safe electrical installation and inspection to protect people and property from electrical hazards.

personal protective equipment—equipment designed to protect workers from serious workplace injuries or illnesses resulting from contact with chemical, radiological, physical, electrical, mechanical, or other workplace hazards. Besides face shields, safety glasses, hard hats, and safety shoes, protective equipment includes a variety of devices and garments such as goggles, coveralls, gloves, vests, earplugs, and respirators.

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Solar ABCs Policy Recommendation:

Module Power Rating Requirements

Prepared by

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March 2011

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Author Biographies

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Alex Mikonowicz is a ISO-9001 Consultant on Quality Systems & Photovoltaic Reliability and the Executive Director of PowerMark, Inc. He has 28 years in the Aerospace & Computer industries and 18 years in Photovoltaic's, managing quality organizations at SolarWorld USA, Siemens and Shell Solar Industries, USA. Five times, he was appointed as an examiner for the Malcolm Baldrige National Quality Award. Mr. Mikonowicz is active on the standards committees of the IEC, IEEE, and ASTM, and is the present USA TAG Technical Advisor (TA) for the IEC-TC 82, and votes on the behalf of US for the IEC, TC-82, Photovoltaic Standards. He holds degrees in electrical engineering and business.

Solar America Board for Codes and Standards

The Solar America Board for Codes and Standards (Solar ABCs) is a collaborative effort among experts to formally gather and prioritize input from the broad spectrum of solar photovoltaic stakeholders including policy makers, manufacturers, installers, and consumers resulting in coordinated recommendations to codes and standards making bodies for existing and new solar technologies. The U.S. Department of Energy funds Solar ABCs as part of its commitment to facilitate widespread adoption of safe, reliable, and cost-effective solar technologies.

For more information, visit Solar ABC's website:
www.solarbcs.org

Acknowledgements

This material is based upon work supported by the U.S. Department of Energy under Award Number DE-FC36-07GO17034.

TABLE OF CONTENTS

DISCLAIMER ii

AUTHOR BIOGRAPHIES iii

SOLAR AMERICA BOARD FOR CODES AND STANDARDS iii

ACKNOWLEDGEMENTS iii

POLICY STATEMENT 1

- Objective 1
- Goals 1
- Audience for Policy 1
- Scope and Limitation of Policy 1
- Motivation for Policy 1
- Solar ABCs Policy Recommendation 2

POLICY JUSTIFICATION 3

- Past Issues 3
- Present Evidence 4

REFERENCES 6

APPENDIX 7

POLICY STATEMENT

Objective:

Develop a Solar America Board for Codes and Standards (Solar ABCs) power rating policy statement that establishes requirements for the procurement of photovoltaic (PV) modules for consumers, states, and organizations providing incentives for PV systems in the United States.

Goals:

The goals of this policy statement are to:

- increase customer awareness of the potential for discrepancy between the name-plate rating and performance of delivered PV modules and define a reasonable expectation for the consistency of these numbers;
- increase customer awareness of the power ratings available to them as a result of the IEC 61853-1 standard and empower customers to better compare the performance of modules under a range of conditions;
- improve the willingness of financial institutions to lend money for PV systems and reduce the risk of investments in PV systems by tightening the tolerance on module ratings.

Audience for policy:

Stakeholders involved in manufacturing, purchasing, financing, or providing incentives for PV modules and systems.

Scope and limitation of policy:

Solar ABCs will continue to recommend policies that address consumer and industry concerns related to the use of various performance, qualification, and safety standards. The power rating policy is a living document, and its scope is influenced by market requirements and the availability of existing standards. This recommended policy is written in conformity with the performance conditions in IEC 61853-1 standard titled *"Photovoltaic (PV) module performance testing and energy rating – Part 1: Irradiance and temperature performance measurements and power rating."*

Motivation for policy:

Without a power rating tolerance policy, some PV modules may continue to have a significantly lower power output than the module's rating indicates. This results in reduced performance of installed PV systems that will not meet consumers' expectations. If overrating of modules continues, it will jeopardize the credibility of PV performance predictions with the general population and could slow progress toward wide adoption of solar energy technologies. This policy is the same as the existing standard used in Europe (EN 50380) with the addition of a specific lower/upper limit for the production tolerance and removing uncertainty on measured power as it varies from one lab to the other and from one test/reference technology to the other. In addition, without power rating data at various low/high irradiance and temperature conditions, the energy collection predictions for installed PV modules and systems will not be accurate.

Solar ABCs Policy Recommendation:

"It is recommended that photovoltaic module types sold or installed in the United States be independently measured and certified to the following power rating tolerance: after accounting for the light induced degradation[1] as per IEC 61215 (crystalline silicon) or IEC 61646 (thin film), the measured average[2] power shall be equal to or higher than the nominal nameplate power rating at STC (standard test conditions) and no individual module power shall be more than 3% below nominal. In addition, the modules shall be rated at a minimum at the four other reference conditions given in IEC 61853-1 standard: 200 W/m² & 25°C cell temperature; 500 W/m² & 15°C cell temperature; 1000 W/m² & 75°C cell temperature; 800 W/m² & 20°C ambient temperature."

Notes:

1. Values shall be measured after preconditioning according to IEC Standard 61215, Section 5, or after light-soaking according to IEC Standard 61646, Section 10.19. Other stabilizing methods may be utilized as recommended by the manufacturer if they are consistent with outdoor operation.

2. The required number of samples (n) for the average is dictated by the standard deviation (σ) of the measured values. A baseline value for σ is calculated from a minimum number of 30 samples. Then this baseline value of σ is used to determine the required number of samples (n) to meet the Policy recommendation. The required number of samples "n" shall be determined using the following method:

   - Note down the nameplate rated power (P_0 in watts).
   - Measure the individual power of 30 modules.
   - Calculate the standard deviation (σ in watts) of these 30 modules.
   - Determine the sample size "n" using the following equation and table:

$$n = (z_{\sigma/2} * \sigma/0.03P_0)^2$$

Desired Confidence Level	$z_{\sigma/2}$
90%	1.645
95%	1.96
99%	2.58
99.9%	3.3

If the "n" value is determined to be higher than 30, then the measured average power shall be based on "n" samples. If the "n' value is determined to be less than 30, then the measured average power shall be based on 30 samples. The "n" value shall be rounded upward. The details on the sample size determination are presented in the appendix. The timeline for module sampling shall be mutually agreed upon between the supplier and customer.

The measurement uncertainty of each test sample at STC along with calibration traceability chain for the measuring equipment and calibrated modules shall be reported. The independent measurements shall be carried out by an ISO 17025 accredited laboratory acceptable to the customer.

POLICY JUSTIFICATION

Past Issues:

Most consumers, system integrators, and agencies providing incentives have relied on the module nameplate ratings to estimate the power and/or energy delivered by installed PV systems. Unfortunately, those estimations often have not met expectations. A possible outcome of this common trend of overstating module power ratings may be a loss of consumer and government confidence in the ability of PV modules and systems to perform as expected. It is important to recognize that the credibility of PV technology depends not only on the quality of the PV products, but also on industry practices. The nominal power ratings listed on the nameplates of PV modules were often found by independent test laboratories to be much higher than the actual measured power. As shown in Figure 1, module testing by the Florida Solar Energy Center indicated that the measured peak power of PV modules in the United States marketplace was typically less than the nameplate value (Atmaram, TamizhMani, & Ventre, 2008). In some cases, the measured power of the modules sourced from the open market was found to be nearly ten percent below the nameplate rating. BEW Engineering reported similar data on installed PV arrays, as illustrated in Figure 2 (Lilly et al., 2006).

In the past, this overrating issue was often attributed to the ANSI/UL 1703 standard (ANSI/UL 1703, 2008, etc.), which states that "the short-circuit current (Isc), rated current (Ir) maximum power (Pmax), and open-circuit voltage (Voc) shall be within ± 10 percent of the rated value." To be clear, the ANSI/UL 1703 standard is a safety standard for PV modules that specifies requirements for the electrical and mechanical safety—it is not a performance or power rating standard—and the use of a safety standard to support the overrating practice is not justifiable.

Initially, a major reason for accepting this wide tolerance was the high measurement reproducibility error among the test labs. But the biggest reason is likely that most modules were used in standalone systems that almost never operated at peak power. The standalone systems were designed to provide power for the worst months of the year, not the best.

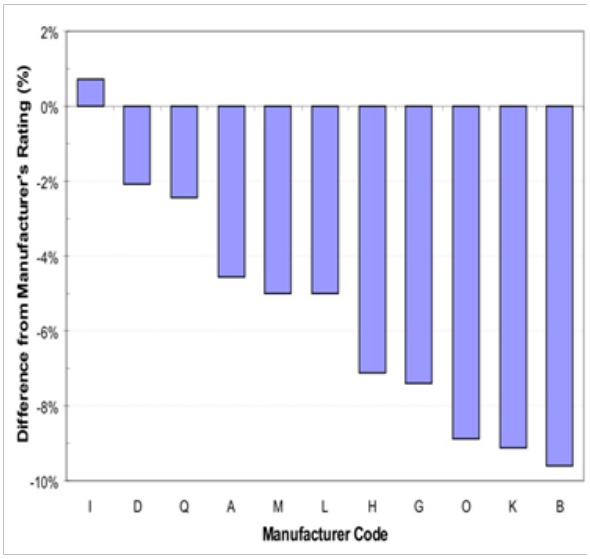

Figure 1: Comparison of measured power with nameplate ratings of modules sourced from open market (Atmaram et al., 2008)

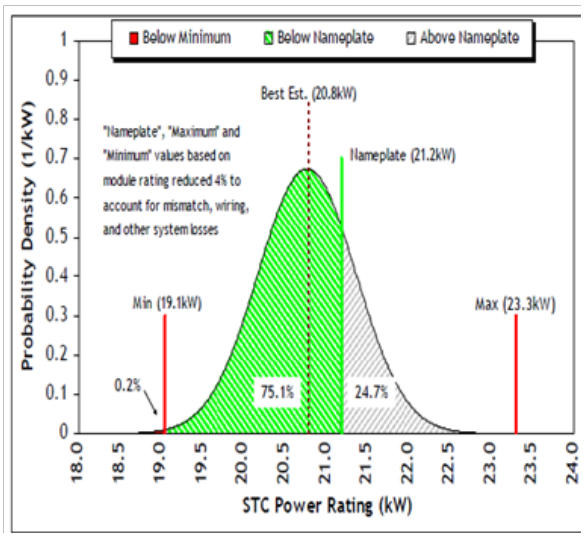

Figure 2: Comparison of the measured power with nameplate ratings of fielded modules (Lilly et al., 2006)

Present Evidence:

Tightening the nameplate power rating tolerance should address the measurement issue related to the reproducibility among test laboratories and the binning/tolerance issue in production lines. Three pieces of objective evidence are presented here—one example to address the first issue and two examples to address the second issue.

Measurement Reproducibility: Every test laboratory has its own inherent uncertainty issues related to measuring the performance of PV modules. These are due to the uncertainties related to the measuring equipment (the I-V curve tracer, for example) and calibration (of the reference cell, for example). The measurement uncertainties vary from one lab to another but they are typically less than 4% for crystalline silicon technologies and as high as 6.5% for thin-film technologies. A major contributor to this module measurement uncertainty is the uncertainty related to reference cell calibration. These uncertainties in turn influence the reproducibility of the results between the test labs. Table 1 indicates that the measurements between a large number of test laboratories can be typically reproduced within about 5% for all the module technologies (Rummel et al., 2006). This indicates great progress by the test/measurement laboratories to tighten measurement uncertainties and improve reproducibility. Measurement uncertainty can be reduced by utilizing reference devices from the same source.

Table 1: Pmax reproducibility between the test/measurement laboratories (% deviation from average)

Reproducibility Tolerance

NREL Round Robin Testing – 2006 (WCPEC4-2006)											
	<Pmax>.W	NREL pre	SNL	ASU	FSEC	ESTI	LEEE	TUV	ISE	JET	NREL post
Mono-Si											
SIE0577	66.84	-2.9	3.2	1.6	-4.2	0.4	-0.2	-0.2	0.8	1.3	-2.6
SIE0586	67.22	-3.2	2.9	1.3	-4.2	0.4	0.6	-0.6	0.7	1.7	-2.8
Thin Film Si											
AsP0123	51.54	-3.5	1.7	0.7		0.9	-1.4	0.3	0.8	-0.6	-2.4
AsP0247	52.87	-3.1	1.8	0.6		1.4	-1.5	0.1	0.6	-0.9	-2.1
a-Si/a-Si/a:Ge											
BPS4213	41.04	4.8	-0.3	2.3		-7.2*		3.3			1.8
BPS4223	36.82	3.7	1.8	3.7		-3.3*		-3.9			1.6
a-Si/a-Si/a-Si											
USSC234	19.24	3.2	-0.6	-0.2		-7.8*		9.1			-0.5
USSC234	19.41	2.7	-0.5	-0.6		-7.2*		8.7			-0.5
CdTe											
BP4405	84.13	0.1	-0.7	4.7		-2.9		-1.0			-0.1
BP4505	87.96	-1 .3	-0.5	4.1		-3.4		-1.0			0.7
CIS											
Sie9257	40.54	-3.3	5.0	3.1		-3.1		-1.3			-3.7
Sie9260	40.10	-3.5	7.6	4.2		-4.7		-3.0			-4.1
Concentrator											
PTEL#1	3.015	3.3	0.8			-3.8					3.0
PTEL#2	2.913	-0.3	3.0			-7.3					4.3

*No special mismatch correction applied.

Production Tolerance: When the industry was producing PV modules at just a few megawatts per year, consumers accepted a wide production tolerance of +/- 10% because of the measurement reproducibility issues, the inherent variations in production lines, and the fact that most modules went to standalone systems where performance variations were not readily apparent. In 2010, the industry produced 18.2 gigawatts of PV modules (SolarBuzz, 2011), and consumers, especially in Europe, have tightened their procurement specifications including the power rating tolerance requirement. In response to increased consumer expectations, all the major manufacturers serving the European market have tightened their nameplate specifications to meet the requirement of the EN 50380 standard (EN 50380, 2003). The EN standard requirement can be presented as the following equation, where "m" is the measurement uncertainty and "t" is the production tolerance.

$$(P_{measured} + m) \geq (P_{rated} - t)$$

The EN standard allows leniency on both sides of the equation: the production tolerance leniency on the right side of the equation and the measurement uncertainty leniency on the left side of the equation. Unfortunately, the measurement uncertainty varies from one lab to another, and one technology to another. Also, the EN standard does not impose any specific lower/upper limit for the production tolerance. Many manufacturers offer data sheets meeting the requirements of the EN standard as shown below. The sampling of major manufactures' data sheets from the Web during 2010 clearly indicates that the manufacturers now have better quality assurance practices (due to improved sorting and better measurement accuracy) and are able to tighten the production tolerances to +/- 3%.

Manufacturer # 1
- Production tolerance = +/- 3%
- The datasheet complies with the requirements of EN 50380 (EN 50380, 2003)

Manufacturer # 2
- Production tolerance = +/- 3%
- The datasheet complies with the requirements of EN 50380

Manufacturer # 3
- Production tolerance = +/- 3%
- No indication of the datasheet complying with the requirements of EN 50380

Manufacturer # 4
- Production tolerance = -5% and +10%
- No indication of the datasheet complying with the requirements of EN 50380

Manufacturer # 5
- Production tolerance = -0% and +5%
- No indication of the datasheet complying with the requirements of EN 50380 but it indirectly complies with EN 50380 as the negative tolerance is 0%

Figure 3 compares the nameplate ratings with the independently measured values of 9,422 modules sold for power plant applications in Europe (Vaassen, 2010). This figure clearly indicates that less than 0.7% of these modules have measured values of less than -3% of the nameplate rated values. Well over 50% of all modules in the study exceeded their rated nameplate power. Again, this confirms that the manufacturers now have better quality assurance practices that allow them to maintain nearly 100% of the production modules above the -3% tolerance limit. Therefore, the Solar ABCs policy has been

designed based on the following two equations, where $P_{measured\text{-}average}$ is the measured average power of "n" samples and $P_{measured\text{-}individual}$ is the measured power of individual samples.

$$P_{measured\text{-}average} \geq P_{rated}$$

&

$$P_{measured\text{-}individual} \geq (P_{rated} - 3\,\%\ \text{tolerance})$$

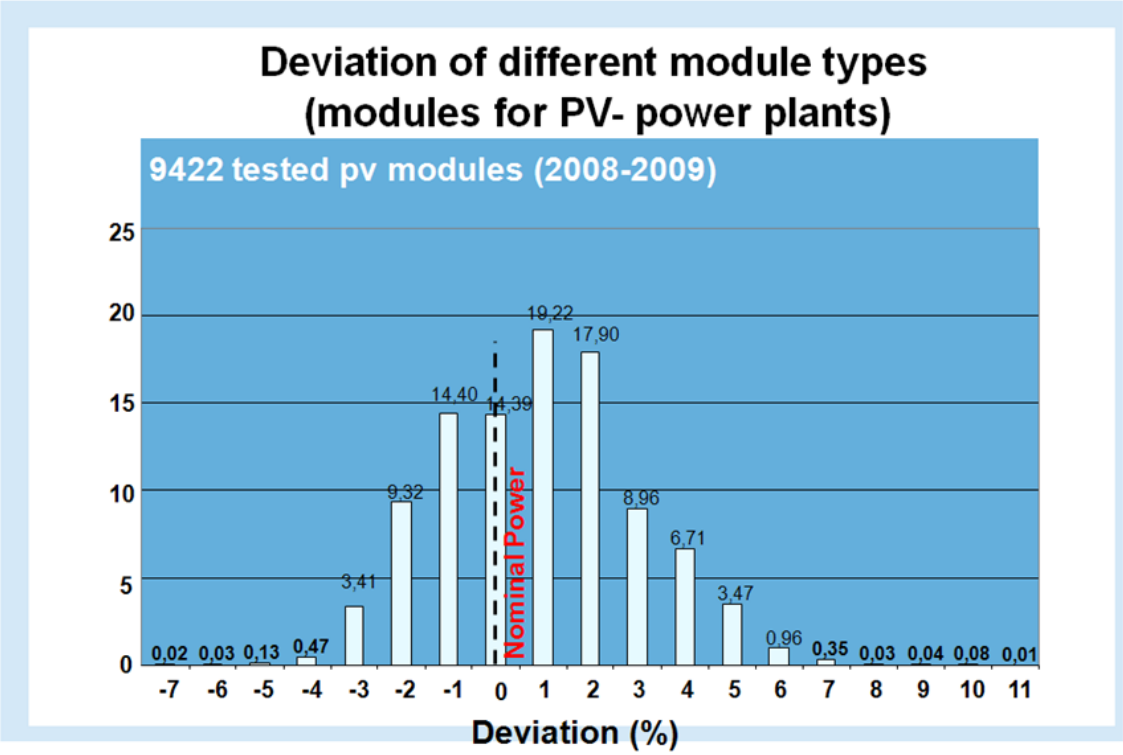

Figure 3: Comparison of the measured power with nameplate ratings of power plant modules (Vaassen, 2010)

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APPENDIX

Sample size (n) determination (J. Kuitche, Arizona State University, personal communication January 2011)

Let's assume we want the measured average power of "n" samples (say, P_r) to be within +/- 3% of the rated value (say, P_0). That is, if we draw a random sample (for example 30 modules) from a production line and compute the average or mean of 30 samples (say, P), then that value (average) shall fall between $0.97P_0$ and $1.03P_0$; with a certain degree of confidence.

We can set our sights on a 95% (2-sigma) or 99% (3-sigma) confidence level, for example. So a 95% confidence interval can be computed as $P_r \pm 2\sigma_P$, where:

$\sigma_P = \sigma/\sqrt{n}$ = standard error of the mean

σ = standard deviation of the sample drawn (30 samples)

n = sample size

Thus, the half-width confidence interval is given by:

$$w = 2 * \sigma/\sqrt{n}$$

More accurately, 95% confidence level <--> $z_{\alpha/2}$ -sigma; so:

$$w = z_{\alpha/2} * \sigma/\sqrt{n}$$

where $z_{\alpha/2}$ can be obtained from statistical tables for any confidence level.
The commonly used values of $z_{\alpha/2}$ are shown in the following table:

Desired Confidence Level	$z_{\sigma/2}$
90%	1.645
95%	1.96
99%	2.58
99.9%	3.3

If the target half-width is 3% P_0 as stated, then:

$$3\%P_0 = z_{\alpha/2} * \sigma/\sqrt{n}$$

$$n = (z_{\alpha/2} * \sigma/0.03P0)^2$$

Notes:

The value of "σ" is estimated from a prior sample (of size 30 above).
The value of "n" obtained shall be rounded upward.
P_r is the average of "n" samples after accounting for the light induced degradation.

A Solar ABCs Proposed Standard on:

Nameplate, Datasheet, and Sampling Requirements of Photovoltaic Modules

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January 2012

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Download a copy of the report:

www.solarabcs.org/nameplate

Executive Summary

The Solar America Board for Codes and Standards (Solar ABCs) recently (March 2011) published a recommended policy report entitled "Photovoltaic Module Power Rating Requirements." The purpose of the report was to develop a Solar ABCs power rating policy statement that establishes requirements for the procurement of photovoltaic (PV) modules for consumers, states, and organizations providing incentives for PV systems in the United States. The purpose of this document, "A Solar ABCs Proposed Standard on Nameplate, Datasheet, and Sampling Requirements of Photovoltaic Modules," is to convert the policy report into a PV module standard with a text format acceptable to the standard developing organizations such as ASTM International, Institute of Electrical and Electronics Engineers (IEEE), and the International Electrotechnical Commission (IEC).

The European Union has developed a related standard (EN 50380) titled "Datasheet and nameplate information for photovoltaic modules." This European standard (EN), published in 2003, details the information that manufacturers must supply with a PV module. The EN requires manufacturers to report module data (voltage, current, and power at maximum power point, V_{oc}, and I_{sc}) at standard test conditions (STC), nominal operating cell temperature (NOCT), and low irradiance conditions (LIC) as well as temperature coefficients.

The proposed standard by the Solar ABCs differs from the EN in three major respects:

Difference 1: The EN requirement can be represented using this equation: $(P_{measured} + m) \geq (P_{rated} - t)$, where "m" is the measurement uncertainty and "t" is the production tolerance.

The above EN requirement allows leniency for the nameplate rating by the manufacturers on both sides of the equation—the production tolerance leniency on the right side of the equation and the measurement uncertainty leniency on the left side of the equation. Unfortunately, the measurement uncertainty varies from one lab to another and one technology to another. Also, the EN does not impose any specific lower/upper limit for the production tolerance. The proposed standard by the Solar ABCs accounts for these issues in the EN.

Difference 2: EN 50380 requires reporting the module data at only three rating conditions: STC, NOCT, and LIC. The newly published (January 2011) standard IEC 61853-1 titled "Photovoltaic Module Performance Testing and Energy Rating" (IEC, 2011) requires reporting the module data at two additional rating conditions of high temperature conditions (HTC) and low temperature conditions (LTC). The proposed standard by the Solar ABCs recommends the use of the test conditions required by the IEC 61853-1 standard.

Difference 3: The EN 50380 standard does not impose any statistical sampling requirement to select the modules for the independent power rating measurements. The proposed standard by the Solar ABCs incorporates a simple statistical sampling method to determine the number of samples required for the power rating measurements by the independent testing organizations.

Author Biographies

Dr. (Mani) Govindasamy TamizhMani is the president of TUV Rheinland PTL (Photovoltaic Testing Laboratory) and a professor in the Department of Electronic Systems at Arizona State University. Dr. Mani has been involved in R&D activities related to photovoltaics and fuel cells for more than 25 years, and photovoltaic module testing and certification activities for more than 10 years. He has been involved in test standard development activities since 1996. He has served or is serving on various standards committees including the Canadian Standards Council, IEEE, IEC, and ASTM. He has taught graduate level courses related to photovoltaics, fuel cells, electrolysis, and batteries, and has published more than 60 journal and conference papers.

Alex Mikonowicz is an ISO-9001 Consultant on Quality Systems & Photovoltaic Reliability and the executive director of PowerMark, Inc. He has spent 28 years in the aerospace and computer industries and 18 years in photovoltaics, managing quality organizations at SolarWorld USA, Siemens, and Shell Solar Industries, USA. He was appointed five times to be an examiner for the Malcolm Baldrige National Quality Award. Mr. Mikonowicz is active on the standards committees of the IEC, IEEE, and ASTM, and is the present USA TAG Technical Advisor for the IEC-TC 82, and votes on the behalf of the United States for the IEC, TC-82, Photovoltaic Standards. He holds degrees in electrical engineering and business.

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Solar America Board for Codes and Standards

The Solar America Board for Codes and Standards (Solar ABCs) is a collaborative effort among experts to formally gather and prioritize input from the broad spectrum of solar photovoltaic stakeholders including policy makers, manufacturers, installers, and consumers resulting in coordinated recommendations to codes and standards making bodies for existing and new solar technologies. The U.S. Department of Energy funds the Solar ABCs as part of its commitment to facilitate wide-spread adoption of safe, reliable, and cost-effective solar technologies.

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Table of Contents

DISCLAIMER ii
EXECUTIVE SUMMARY iii
AUTHOR BIOGRAPHIES iv
SOLAR AMERICA BOARD FOR CODES AND STANDARDS iv
SCOPE OF PROPOSED STANDARD 1
OVERALL REQUIREMENTS OF STANDARD 2
NAMEPLATE REQUIREMENTS 2
DATASHEET REQUIREMENTS 2
SAMPLING REQUIREMENTS 3
REFERENCES 4
APPENDIX: Sample Size (n) Determination 5
ACRONYMS 7

Nameplate, Datasheet, and Sampling Requirements of Photovoltaic Modules

1. Scope

1.1 This standard identifies the required information on the production and measurement tolerances of nameplate rating of flat plate photovoltaic (PV) modules.

1.2 This standard identifies five rating conditions under which the performance parameters of PV modules shall be reported.

1.3 This standard identifies a simple statistical method to determine the number of samples required for the power rating measurements.

1.4 The samples shall be drawn at random by the responsible authority without regard to their quality as defined in ANSI/ASQ Z1.4 (ANSI/ASQ, 2003). The responsible authority is a representative agreed between purchaser and seller or producer and user.

1.5 The power rating measurements shall be carried out by the independent testing organizations.

1.6 When specified by the responsible authority, this standard shall be referenced in the specification, contract, inspection, instructions, or other documents. The "responsible authority" shall be designated in one of the above documents.

1.7 This standard requires that the nameplate on the PV module carry certain minimum information identified in this standard.

1.8 This standard requires that the datasheet supplied by PV module manufacturers carry certain minimum information identified in this standard.

1.9 Unless otherwise agreed between purchaser and seller or producer and user, every model/type label rating shall be tested to this standard. For the purpose of this standard, a model/type is defined as modules that have a nameplate rating within 5% of the tested modules as per this standard.

1.10 This standard does not specify annual sampling frequency and it shall be agreed upon between purchaser and seller.

1.11 This standard does not apply to concentrator PV modules.

2. Overall Requirements of the Standard

After accounting for the light induced degradation as per IEC 61215 (crystalline silicon) (IEC, 2005) or IEC 61646 (thin film) (IEC, 2008), the measured average power shall be equal to or higher than the nominal nameplate power rating at STC and no individual module power shall be more than 3% below nominal. These requirements are represented by the following two equations:

$P_{measured,\ average} \geq P_{rated,\ nominal}$

&

$P_{measured,\ individual} \geq (P_{rated,\ nominal} - 3\%\ \text{production tolerance})$

where $P_{measured,\ average}$ is the measured average power of "n" samples and $P_{measured,\ individual}$ is the measured power of individual samples. $P_{measured,\ average}$ is the independently measured average power of "1-to-100" samples (n). The number of samples "n" must be calculated as described in Section 5 below.

In addition, a minimum of one module (more modules may be required as dictated by the purchaser or user) closest to the nominal rated power shall be measured at the other four rating conditions given in the IEC 61853-1 standard (NOCT, LIC, HTC, and LTC). All five rating conditions are presented in Table 1 below. The nameplate on the individual PV modules shall carry the minimum information identified in Section 3 below. Similarly, the datasheet supplied by the PV module manufacturer shall carry the minimum information identified in Section 4 below. The number of samples used to calculate the measured average power shall be determined using the method identified in Section 5 of this standard.

3. Nameplate Requirements

The nameplate on the individual PV modules shall carry the following minimum information:

- Name and logo of original manufacturer or supplier
- Type designation and serial number
- Maximum system voltage
- Rated nominal power (P_{max}) at STC (1000 W/m², 25°C cell temperature, and air mass [AM] 1.5 global spectrum)
- Maximum negative production tolerance (- % or ± %) of P_{max} at STC
- Rated nominal short circuit current (I_{sc}), open circuit voltage (V_{oc}), voltage at maximum power point (V_{max}), and current at maximum power point (I_{max}) at STC.

4. Datasheet Requirements

The datasheet supplied by the PV module manufacturer shall carry the following minimum information:

- All the nameplate information identified in Section 3 of this standard
- Temperature coefficients (%/°C) of V_{oc}, I_{sc}, and P_{max} at STC
- Performance data for at least one module closest to the nominal rated power measured by an acceptable independent laboratory at the five rating conditions given in IEC 61853-1 standard and shown in Table 1 below. In addition, the independent laboratory shall report the uncertainty of measured value at each test condition shown in Table 1, and the uncertainty value of the measured STC data shall appear on the datasheet.

- Number of samples used by the independent test lab to obtain measured average power
- Measured power of all the individual modules used to obtain average power
- The measurement uncertainty of each test sample at STC along with calibration traceability chain for the measuring equipment of the test laboratory and calibrated modules used in the production line by the manufacturer
- A statement from the manufacturer attesting that the test modules were stabilized by the independent test laboratory for light induced degradation by preconditioning the test samples according to IEC Standard 61215 (crystalline silicon), Section 5, or after light soaking according to IEC Standard 61646 (thin film), Section 10.19, or other stabilizing methods as recommended by the manufacturer (if they are consistent with outdoor operation)
- Name and address of the responsible authority, as agreed between purchaser and seller or producer and user, for random sample selection from production lines
- A statement from the manufacturer confirming that the sampling requirements identified in Section 5 of this standard are met by the responsible authority
- Name of an acceptable independent ISO 17025 accredited laboratory that measured the test samples.

Table 1: Five Rating Conditions as Required by IEC 61853-1 Standard

Abbreviation	Description	Irradiance (W/m^2)	Module Temperature (°C)	Ambient Temperature (°C)	Wind Speed (m/s)	Spectrum
HTC	High temperature conditions	1000	75	---	---	AM 1.5
STC	Standard test conditions	1000	25	---	---	AM 1.5
NOCT	Nominal operating cell temperature conditions	800	---	20	1	AM 1.5
LTC	Low temperature conditions	500	15	---	---	AM 1.5
LIC	Low irradiance conditions	200	25	---	---	AM 1.5

5. Sampling Requirements

The samples shall be drawn at random by the responsible authority without regard to their quality as defined in ANSI/ASQ Z1.4 (ANSI/ASQ, 2003). $P_{measured,average}$ is the independently measured average power of "1-to-100" samples (n). The exact number of samples "n" to be used by the independent testing lab is determined based on the percent standard deviation "σ (%)" of 30 (thirty) samples provided by the manufacturer from a production batch or batches acceptable to the sampling procedure of the responsible authority. Table 2 identifies the required number of samples (n) depending on the standard deviation of 30 samples. A detailed explanation of the statistical approach for the sample size determination is provided in the appendix.

Table 2: Sample Size Determination Based on the Standard Deviation of 30 Samples
(Supplied by Manufacturer and Acceptable to Responsible Authority)

σ (%)	≥ 6.0	≥ 5.0, < 6.0	≥ 4.3, < 5.0	≥ 3.8, < 4.3	≥ 3.0, < 3.8	≥ 2.5, < 3.0	≥ 2.1, < 2.5	≥ 1.8, < 2.1	≥ 1.7, < 1.8	≥ 1.5, < 1.7	≥ 1.4, < 1.5	≥ 1.2, < 1.4	≥ 1.0, < 1.2	≥ 0.7, < 1.0	< 0.7
n	100	75	50	40	30	20	15	10	8	6	5	4	3	2	1

REFERENCES

American National Standards Institute (ANSI)/ American Society for Quality (ASQ). (2003). ANSI/ASQ Z1.4. *Sampling procedures and tables for inspection by attributes.*

International Electrotechnical Commission (IEC). (2005). IEC 61215. *Crystalline silicon terrestrial photovoltaic (PV) modules-Design qualification and type approval.*

International Electrotechnical Commission (IEC). (2008). IEC 61646. *Thin film terrestrial photovoltaic (PV) modules-Design qualification and type approval.*

International Electrotechnical Commission (IEC). (2011). IEC 61853-1. *Photovoltaic module performance testing and energy rating.*

Appendix: Sample Size (n) Determination

The required number of samples (n) for the average is dictated by three parameters:

- The maximum production tolerance (E) allowed by the specification, currently 3 %
- The population standard deviation, σ
- The degree of confidence.

Assuming a normal population,
Let $\lambda = E/\sigma$, the ratio of the production tolerance and standard deviation; i.e. 3 % P/σ

We hypothesize that:

- Ho: The measured mean (a) is equal to the nominal mean (μ)
- H1: The two means are not equal.

The degree of confidence defines the risk involved in rejecting Ho when it is actually true. Such probability is set to 5 % (i.e. 95 % confidence level).

To choose a proper sample size for 95 % confidence level, the table below, derived from operating curves of Figure 1, will be used. It plots the risk of mistakenly accepting that the measured mean is equal to the nominal mean, against λ for given sample size. Note that the table was generated based on the fact that all independently measured P_{max} data shall be within 3 % of the rated value.

Estimating Standard Deviation "σ"

When historical data is available (assuming the sample size is larger than 30), it can be used to estimate the population standard deviation σ. However, when there is no such historical data, conventional statistical understanding calls for a minimum of 30 samples to obtain a normal distribution. The manufacturer shall supply the standard deviation (in %) based on the in-line flash tests and the sampling procedure accepted between the manufacturer and the "responsible authority." The flash tester shall be calibrated using calibrated modules as per the quality system traceability requirements of the standard.

Estimating Sample Size "n"

For example, assuming a maximum population standard deviation of 1 % (based on historical/typical data), from table below, a minimum of 3 samples would be required.

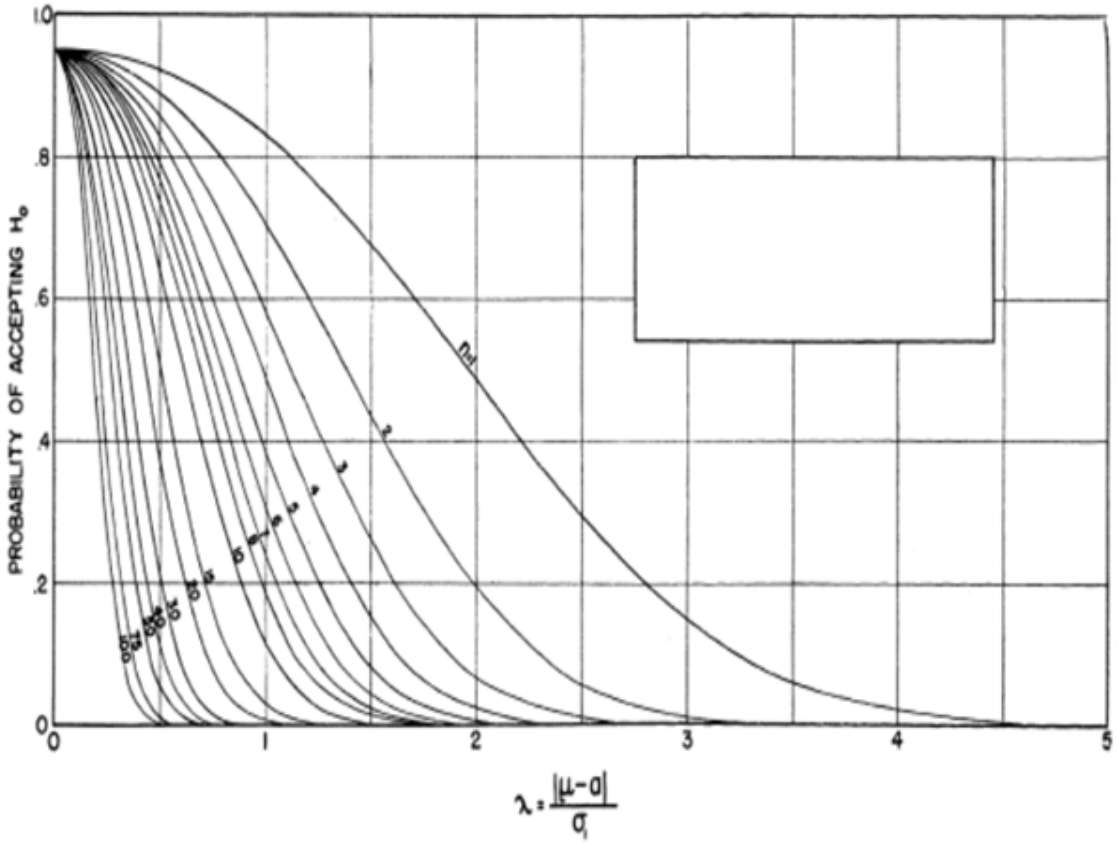

Figure 1: Operating Characteristic curve for 95% confidence and available historical data

(Reproduced from "*Operating Characteristics For The Common Statistical Tests Of Significance*", C. D. Ferris, F. E. Grubbs, and C. L. Weaver, The Annals of Mathematical Statistics, June 1946)

σ (%)	≥ 6.0	≥ 5.0, < 6.0	≥ 4.3, < 5.0	≥ 3.8, < 4.3	≥ 3.0, < 3.8	≥ 2.5, < 3.0	≥ 2.1, < 2.5	≥ 1.8, < 2.1	≥ 1.7, < 1.8	≥ 1.5, < 1.7	≥ 1.4, < 1.5	≥ 1.2, < 1.4	≥ 1.0, < 1.2	≥ 0.7, < 1.0	< 0.7
n	100	75	50	40	30	20	15	10	8	6	5	4	3	2	1

ACRONYMS

AM	air mass
ANSI	American National Standards Institute
ASTM	ASTM International (formerly the American Society for Testing and Materials)
ASQ	American Society for Quality
E	maximum production tolerance
EN	European standard (French: Norme, German: Norm)
HTC	high temperature conditions
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
I_{max}	current at maximum power point
I_{sc}	short circuit current
LIC	low irradiance conditions
LTC	low temperature conditions
n	number of samples
NOCT	nominal operating cell temperature
P_{max}	peak power
PV	photovoltaic
STC	standard test conditions
V_{max}	voltage at maximum power point
V_{oc}	open circuit voltage

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ABCS-06-SR

Photovoltaic Module Power Rating per IEC 61853-1 Standard:

A Study Under Natural Sunlight

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Photovoltaic Module Power Rating per IEC 61853-1 Standard

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March 2011

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Executive Summary

Photovoltaic (PV) modules are typically rated at standard test conditions (STC) of 25°C cell temperature, 1000 W/m^2 irradiance, and air mass (AM) 1.5 global (G) spectrum. However, the PV modules in the field operate over a range of temperatures, irradiance, and spectra. Recognizing this issue, the International Electrotechnical Commission (IEC) Technical Committee 82 Working Group 2 (TC82/WG2) has been developing an appropriate power and energy rating standard (IEC 61853) for more than 15 years. The first part of this four-part standard requires the generation of a 23-element maximum power (P_{max}) matrix at four different temperatures and seven different irradiance levels. The P_{max} matrix can be generated using an indoor solar simulator method or outdoor natural sunlight method. The outdoor test method introduces little/no spectral mismatch error and is much less expensive than the indoor test method because it avoids the use of very expensive solar simulators. However, obtaining an accurate and repeatable P_{max} matrix using the outdoor method over time (several months or years) would be extremely challenging. The objectives of this study related to the power rating of PV modules using natural sunlight were to:

- identify measurement repeatability issues with a non-standardized test setup,
- standardize the measurement setup,
- verify the device linearity per IEC 60904-10,
- generate the power (P_{max}) matrix per IEC 61853-1, and
- validate four different current-voltage translation/interpolation techniques of IEC 60891 and the National Renewable Energy Laboratory Method (NREL Method).

This study report deals with two rounds of outdoor measurements and results to realize the above five objectives. We carried out the round one (2009) measurements to identify the repeatability issues of the non-standardized test setup. We carried out the round two (2010) measurements to standardize the test setup, check the PV device linearity, generate the P_{max} matrix, and validate four different current-voltage (I-V) translation/interpolation techniques of IEC 60891 and NREL Method.

Based on the round one 2009 study, we concluded that the repeatability issues can be minimized to an acceptable level by an appropriate selection of outdoor measurement conditions and test equipment. Outdoor measurement conditions should be clear sunny days ($>$ 90% direct normal irradiance) at lower air mass values ($<$ 2.5). Test equipment should include:

- a manual or automatic two-axis tracker for tracking the sun;
- a fast ($<$ 1 second) I-V curve tracer to minimize issues related to changing irradiance, spectrum, and module temperature;
- a matched technology (or matched spectral response) reference cell to practically eliminate spectral mismatch error;
- a transmittance calibrated neutral-density mesh screen with good spatial uniformity to change the irradiance level (to improve the light uniformity on the module, a 1.5-inch minimum distance shall be maintained between test module surface and mesh screen, and to accurately measure the irradiance without screen thread shadowing, the small area reference cell used in the test setup shall be kept outside the screen); and
- a pre-cooled test module to naturally change the module temperature while exposed to sunlight (to obtain data at the temperature of 75°C, a thermal insulating foam can be used to cover the backside of test module).

The 2010 measurements with the standardized test setup (2-inch module-to-screen gap and matched reference cells kept outside the screen) were used to verify the device linearity and to demonstrate that the 23-element P_{max} matrix of IEC 61853-1 standard can be generated using 8 to 23 measured reference I-V curves and four translation/interpolation procedures of IEC 60891 and NREL Method. This study used 23 reference curves for the first two procedures (called translation procedures 1 and 2), and 8 to 10 reference curves for the other two procedures (called interpolation procedures 3 and 4). Procedures 1 and 2 required the use of five mesh screens, and procedures 3 and 4 required only three or four mesh screens to generate the entire 23-element P_{max} matrix of IEC 61853-1. This report presents the power rating results for four commercial module technologies—crystalline silicon (c-Si); amorphous silicon (a-Si); cadmium telluride (CdTe); and copper indium gallium diselenide (CIGS). We also present a detailed investigation on the validation of the four translation/interpolation procedures for all four technologies.

Here are the major conclusions corresponding to the five objectives:

- *Outdoor measurement repeatability issues*: The repeatable power rating measurements at various irradiance levels under natural sunlight within an acceptable deviation limit of 2% could not be achieved when uncalibrated mesh screens were placed directly (0-inch distance) on the test module and reference cell.

- *Standardization of measurement setup:* A standardized measurement setup was established with reference cells kept outside the calibrated mesh screens, which were placed at a 2-inch distance above the test modules.

- *Verification of device linearity per IEC 60904-10:* The linearity requirements of open-circuit voltage, short-circuit current, and maximum power versus temperature are met by all four test technologies. Similarly, the linearity requirement of open-circuit voltage versus the logarithm of irradiance is also met (with two minor exceptions presumably due to some experimental errors) by all four test technologies. For the short-circuit current versus irradiance, the devices met the linearity requirement (2% deviation limit) for irradiance levels above 200 W/m^2 but they surprisingly showed a higher deviation for the irradiance levels below 200 W/m^2. This higher deviation was objectively attributed to some minor experimental errors related to the calibration of low transmittance mesh screens under natural sunlight.

- *Generation of P_{max} matrix per IEC 61853-1:* The required 23-element P_{max} matrix of IEC 61853-1 was successfully generated for all four module technologies using the four translation/interpolation procedures of IEC 60891 and NREL Method. Unless the data processing personnel pay extreme attention or commercial test laboratories automate the data processing, the translation procedures (1 and 2) are more prone to human error than the interpolation procedures (3 and 4). However, procedures 1 and 2 would work extremely well if multiple narrow irradiance ranges are used with individual sets of correction values for each narrow irradiance range or multiple sets of correction values are used for a single wide irradiance range.

- *Validation of procedures of IEC 60891 and NREL Method:* An extensive validation analysis of the four translation/interpolation procedures, at both narrow and wide irradiance ranges indicates that all four procedures are remarkably accurate within an average error of 3% and a root mean square error (RMSE) of 4.5%.

Author Biographies

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Ms. Karen Paghasian, Mr. Joseph Kuitche, Ms. Meena Gupta Vemula, and Mr. Ganesh Sivasubramanian are graduate students at Arizona State University.

Acknowledgements

The authors gratefully acknowledge the scientific and editorial comments of all the reviewers, especially Dr. John Wohlgemuth, Dr. Bill Marion, Dr. Sarah Kurtz, Dr. Gary Nakarado, Mr. Howard Barikmo, and Mr. Dave Click. Thanks to TUV Rheinland PTL for the permission to carry out some of the experiments in their facility.

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Table of Contents

Disclaimer ii

Executive Summary iii

Author Biographies v

Acknowledgements v

Solar America Board for Codes and Standards v

INTRODUCTION 1

BACKGROUND 1

OUTDOOR POWER RATING MEASUREMENTS 2

Round One Measurements (2009) 3

Measurements With Non-Standardized Test Setup 3

Light Transmittance 3

P_{max} Matrix Generation 9

Round Two Measurements (2010) 15

Measurements With Standardized Test Setup 15

Light Transmittance of Calibrated Mesh Screens 15

Linearity of Test Modules With Temperature and Irradiance 16

P_{max} Matrix Generation With Mesh Screen Placed 2 Inches Above Module Surface 22

Validation of Current-Voltage Translation/Interpolation Procedures 25

CONCLUSIONS 28

REFERENCES 29

APPENDIX 30

ACRONYMS 40

Introduction

This study report addresses five objectives related to the power rating of photovoltaic (PV) modules using natural sunlight. These objectives are to:

- identify measurement repeatability issues with a non-standardized test setup,
- standardize the measurement setup,
- verify the device linearity per IEC 60904-10,
- generate the power (P_{max}) matrix per IEC 61853-1, and
- validate four different current-voltage (I-V) translation/interpolation techniques of IEC 60891 and the National Renewable Energy Laboratory Method (NREL Method).

Background

Manufacturers typically rate PV modules at standard test conditions (STC). The STC rating involves only one temperature (25°C), one irradiance (1000 W/m^2), and one sunlight spectrum (AM [air mass] 1.5G [global]). However, the actual energy production of field installed PV modules is a result of a range of operating temperatures, irradiances, and sunlight spectra. Therefore, there is an urgent need to characterize PV modules at different temperatures and irradiances to provide more comprehensive rating information.

One of the most relevant PV standards being developed by the International Electrotechnical Commission (IEC) Technical Committee 82 Working Group 2 (IEC/TC82/WG2) is the IEC 61853 standard titled *Photovoltaic Module Performance Testing and Energy Rating* (IEC, 2011). This standard consists of four parts:

- *IEC 61853-1: Irradiance and temperature performance measurements and power rating*, which describes requirements for evaluating PV module performance in terms of power (watts) rating over a range of irradiances and temperatures;
- *IEC 61853-2: Spectral response, incidence angle, and module operating temperature measurements*, which describes test procedures for measuring the effect of varying angle of incidence and sunlight spectra as well as the estimation of module temperature from irradiance, ambient temperature, and wind speed;
- *IEC 61853-3: Energy rating of PV modules*, which describes the calculations for PV module energy (watt-hours) ratings; and
- *IEC 61853-4: Standard days*, which describes the standard time periods and weather conditions that can be used for the energy rating calculations.

IEC published the first part of the standard in January 2011. This standard specifies the performance measurements of PV modules at 23 different sets of temperature and irradiance conditions, as shown in *Table 1*, using either a solar simulator (indoor) or natural sunlight (outdoor). There are several possible indoor and outdoor techniques, and this standard allows many of them. Validation of these techniques for repeatability over time within the same laboratory and for reproducibility among multiple laboratories is extremely important for the successful implementation of this standard. The power rating measurements at various temperatures and irradiance levels are more challenging under prevailing outdoor conditions than under controlled indoor conditions.

This study report deals with two rounds of outdoor measurements and results. In round one (2009), we carried out measurements to identify various test setup issues and select a test setup. In round two (2010), we carried out measurements to standardize the test

setup, generate the 23-element P_{max} matrix of IEC 61853-1, and validate four different I-V translation/interpolation techniques of IEC 60891 (IEC, 2009) and NREL Method (Marion, Rummel, and Anderberg, 2004). We studied four different commercial PV technologies—crystalline silicon (c-Si), amorphous silicon (a-Si), cadmium telluride (CdTe), and copper indium gallium diselenide (CIGS). We limited this study to the repeatability (within laboratory) issues excluding the reproducibility (among the laboratories) issues. We carried out all the measurements at AM levels less than 2.5, and with matched reference cell technologies to minimize the spectral mismatch error (Lad, 2010). A detailed version of this report is presented elsewhere (Paghasian, 2010).

Table 1

I_{sc}, P_{max}, V_{oc}, and V_{max} at 23 Sets of Irradiance and Temperature Conditions

Irradiance (W/m^2)	Module Temperature (°C)			
	15	25	50	75
1100	NA	1	2	3
1000	4	5	6	7
800	8	9	10	11
600	12	13	14	15
400	16	17	18	NA
200	19	20	21	NA
100	22	23	NA	NA

Outdoor Power Rating Measurements

We carried out the outdoor power rating measurements in Tempe and Mesa, Arizona (a desert climatic condition) using IEC 61853-1 standard's Technique-3 of Clause 9.1.4: Pre-condition the test specimen to a point below the target temperature and then let the module warm up naturally. We chose clear sunny days, and used a module placed on a manual two-axis tracker (see Figure A1 in Appendix for the test setup details) when the AM was less than 2.5.

As shown in Table 2, we studied four commercial flat-plate module technologies—c-Si, a-Si, CdTe, and CIGS. To measure incident irradiance on the test modules with minimized spectral mismatch errors, we used appropriate reference cells as shown in Table 2 (Lad, R., 2010). To obtain data at various irradiance levels, we used different mesh screens with varying light transmittance (see Figure A2 in the Appendix for the screen details). To obtain data at various temperatures, we pre-cooled the test module in an air-conditioned wooden cabinet or an environmental chamber, and then took a series of I-V measurements under sunlight while the module warmed up naturally. To obtain data at temperatures higher than 45°C, we covered the test module's backsheet with a thermal insulator.

We took two rounds of measurements. The round one (2009) measurements helped us to identify the repeatability issues of non-standardized test setups and select a test setup. We carried out the round two (2010) measurements to finalize the standardized test setup, check the PV device linearity, generate the P_{max} matrix, and validate four different I-V translation/interpolation techniques of IEC 60891 and NREL Method (IEC, 2009) (Marion, B. et al., 2004).

Table 2
Test Module Technologies and Corresponding Reference Cell Technologies Used in This Investigation
(we used two reference cells for redundancy and cross checking purposes)

Test Module Technology	Reference Cell Technology	
	Primary Reference Cell	Secondary Reference Cell
Monocrystalline Silicon (mono-Si)	Mono-Si	Mono-Si
Amorphous Silicon (a-Si)	Mono-Si (filtered)	Mono-Si
Cadmium Telluride (CdTe)	GaAs	Mono-Si
Copper Indium Gallium Diselenide (CIGS)	Mono-Si	Mono-Si

Round One Measurements (2009)

Measurements With Non-Standardized Test Setup

In the non-standardized test setup, the reference cells were placed under the uncalibrated mesh screen and the mesh screen was placed directly on the module with no air gap between the module surface and the mesh screen. This setup has two major advantages—the mesh screen does not need to be calibrated for light transmittance, and the flexible mesh screen can be simply placed (rolled around) on the module with no need for rigid framing or a support structure. However, this setup introduced measurement accuracy and repeatability issues involving light transmittance and P_{max} matrix generation.

Light Transmittance

The uncalibrated mesh screens can be used to reduce irradiance levels on the test module. However, this method requires that the calibrated reference cells be placed under the screens. Because the area of a typical reference cell is very small (less than one inch by one inch), the reference cell output is very sensitive to the spatial uniformity of the mesh screen. We used five mesh screens (see Figure A2 in Appendix for details) to reduce the irradiance level on the test modules. These screens are designated as S-100 (smallest opening screen providing approximately 10 % transmittance), S-200, S-400, S-600, and S-800 (largest opening screen providing approximately 80 % transmittance). The reference cell output was recorded using a data logger to measure the irradiance values at predetermined locations below the screen. The percent transmittance of light for each of the five screens was determined on a clear day using a two-axis tracker and two calibrated reference cells used as irradiance sensors—one outside the screen and the other under the screen.

Measurement accuracy of the light under a screen could be affected either by the mesh opening dimension with respect to reference cell dimension or by the number of openings per unit area (spatial non-uniformity) from one position to the other of the screen. The IEC 61853-1 standard specifies that the maximum filter mesh opening dimension shall be less than 1 % of the maximum linear dimension of the reference device. This specification is met by the small opening screens (used in this study) but not by the large opening screens such as S-800. We determined the spatial non-uniformity of each screen by moving the screen over a 1-inch by 1-inch calibrated reference cell with 0-inch screen distance from the reference cell.

The second calibrated reference cell used outside the screen accounts for the incident irradiance variability, if any, outside the screen. We moved each screen in a row from one end to the other along the length of the screen. We did this experiment—using a test platform normal to the sun—very quickly on a perfectly clear sunny day while the irradiance was constant. The irradiance data were continuously recorded during the entire time of the experiment. As shown in Figure 1, the entire screen (100-inch by 50-inch) was divided into four rows along the width and 25 columns along the length for spatial uniformity mapping. We present the results for the S-800 screen in Figure 2. The variability chart and contour map shown in Figure 2 indicate that there is a large variation in irradiance values across the screen.

The spatial non-uniformity influence on the irradiance measurement can be reduced if the 1-inch by 1-inch reference cell is replaced with a 4-inch by 4-inch reference cell. The results obtained with the 4-inch by 4-inch cell are shown in Figure 3. The lower standard deviation with 4-inch by 4-inch reference cell—4.7 W/m^2 for S-800 screen compared with 7.5 W/m^2 for S-800 screen for the 1-inch by 1-inch reference cell—further indicates an improvement in measurement accuracy with the 4-inch by 4-inch reference cell. We attribute the 4% difference in irradiance between Figures 2 and 3 to the fluctuation in the incident irradiance outside the screen at the time of testing. Figure 4 shows the distribution and deviation of data points for the S-800 screen, at and from the average (shown by a horizontal line) for small (1-inch by 1-inch) and large (4-inch by 4-inch) area reference cells. This indicates that the spatial uniformity of the light under the screen is heavily influenced by the size of the test device or the size of the solar cell in a module. Increasing the distance between the screen and the test/reference device, which we discuss below, can further reduce the irradiance measurement error due to spatial non-uniformity.

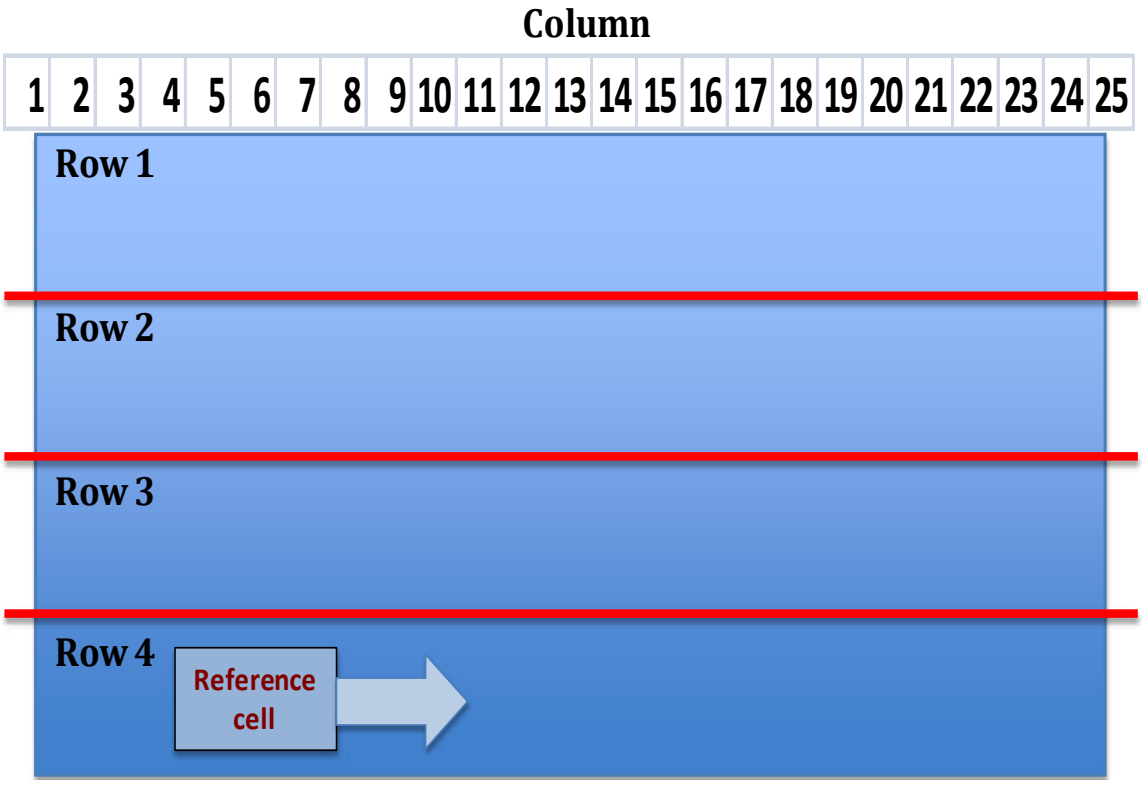
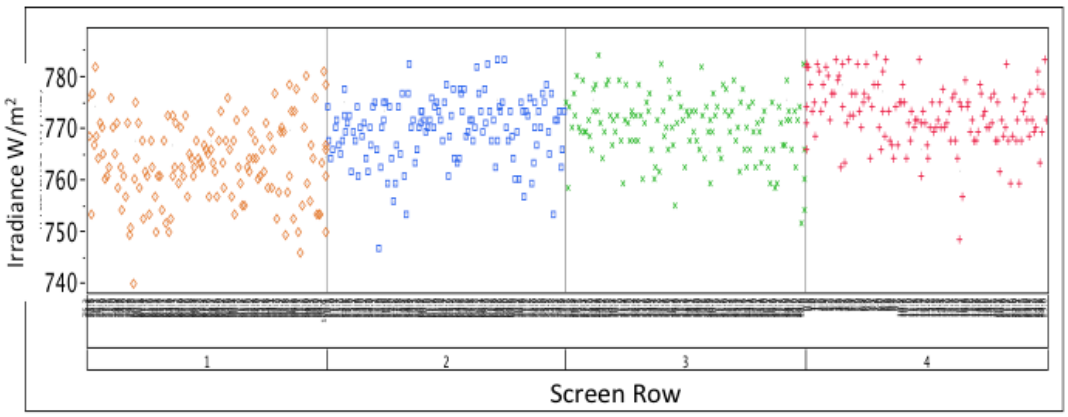


Figure 1. Division of a mesh screen for spatial uniformity determination.

a) Variability chart



b) Contour map

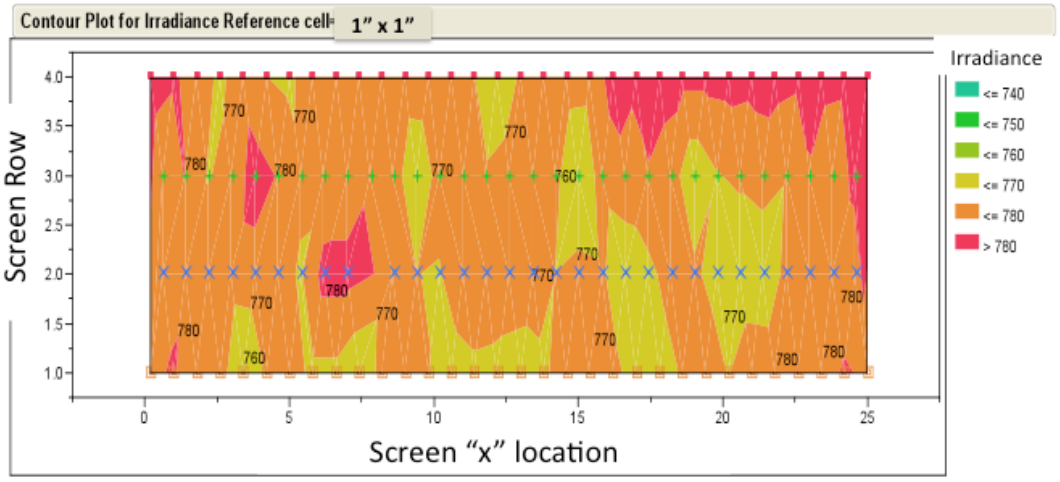
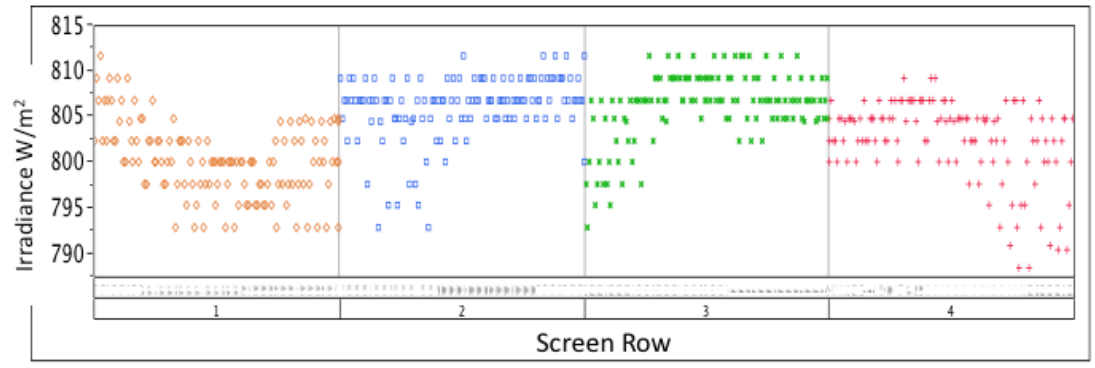


Figure 2. a) Variability chart. b) Contour map showing uniformity mapping of S-800 screen using 1-inch by 1-inch polycrystalline reference cell (0-inch distance between the cell and screen).

a) Variability chart



b) Contour map

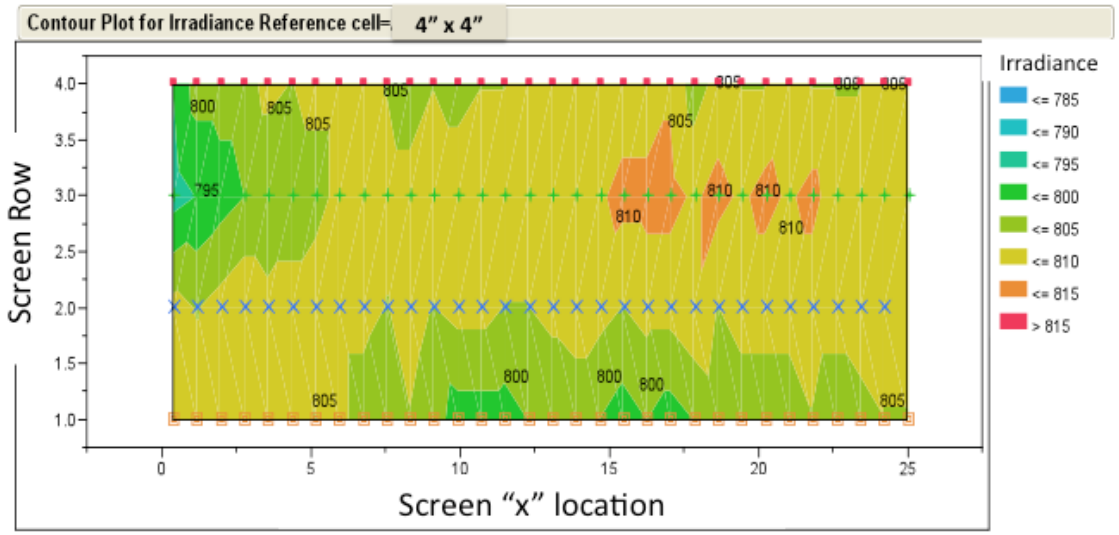


Figure 3. a) Variability chart. b) Contour map on uniformity improvement of S-800 screen for 4-inch by 4-inch reference cell (0-inch distance between the cell and screen).

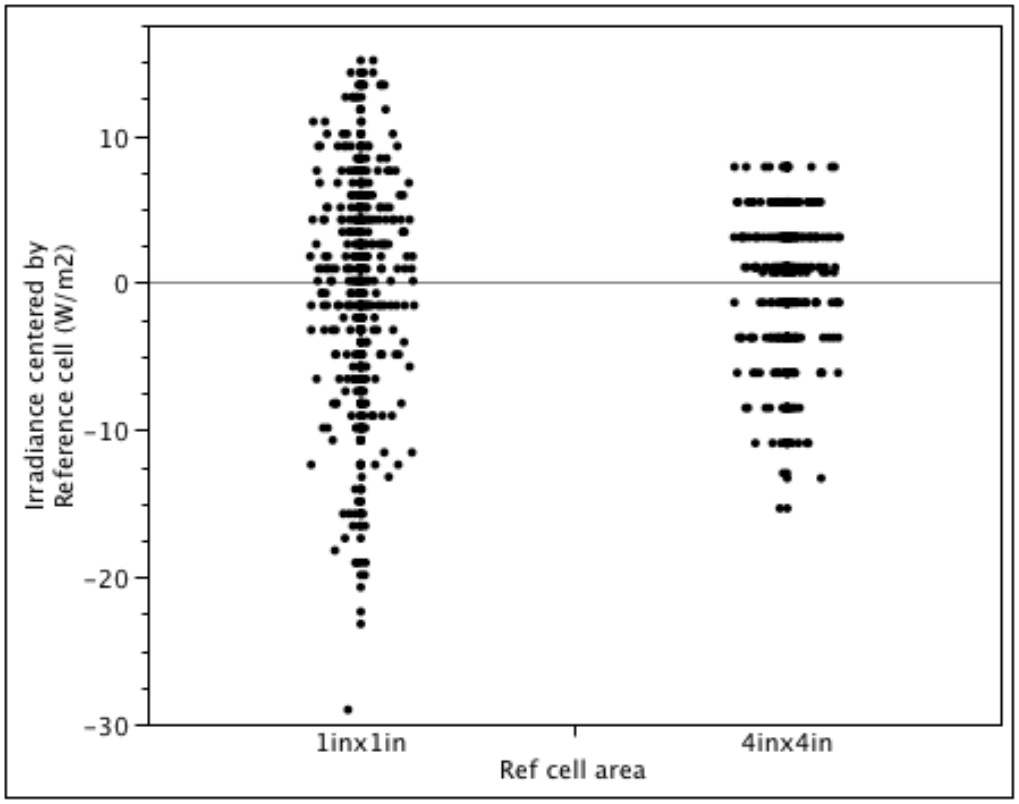


Figure 4. Deviation of data points from the average for small (1-inch by 1-inch) and large (4-inch by 4-inch) area irradiance sensors (S-800 screen, 0-inch screen gap from irradiance sensor).

As shown above, the spatial uniformity of the screens has an influence on the irradiance measurements (and hence module performance measurements). One way to reduce this spatial non-uniformity issue to a negligible level is to increase the distance/gap between the module (and reference cell) surface and the screen. We used the S-800 screen to determine the optimum gap distance between the test device (in this case a 1-inch by 1-inch reference cell) and the screen. We arbitrarily chose the distances of 0, 1.5, 3, and 6.5 inches, and then compared the collected irradiance data with the 0-inch irradiance data. We collected data at six different locations under each of the screens, totaling about 40 data points at each location (including the 0-inch location), for a grand total of about 240 data points for the six locations. We monitored the slight variation, if any, in intensity of sunlight outside the screen using a reference cell, and we accounted/normalized the variation to calculate the average and standard deviation of light intensity under the screen. Table 3 shows the average and standard deviation for these six locations at each of four distances. The 0-inch data showed a standard deviation of 7.1 W/m^2, and the 1.5 to 6.5 inch data shows a standard deviation of only 4.5 to 5.7 W/m^2, indicating a great improvement in spatial uniformity if the distance is increased from 0-inch to or above 1.5-inch (the reduction in standard deviation between three-inch and 6.5-inch data is significant but we did not repeat the experiment to determine if this reduction is real). Figure 5 is a visual representation of the distribution of these 240 data points for each of the distances. The green line across the data points indicates the average. Therefore, this study recommends maintaining a minimum distance of 1.5 inches between the module and screen. Table 4 shows the transmittance data obtained on all the screens with a distance of 6.5 inches.

Table 3

Influence of Gap Between the Screen and Irradiance Sensor on the Average and Standard Deviation

Distance (inch)	Number of Data Points	Mean (W/m^2)	STD Dew (W/m^2)
0	240	845.6	7.07
1.5	240	841.6	5.72
3	240	838.7	5.51
6.5	240	844.6	4.57

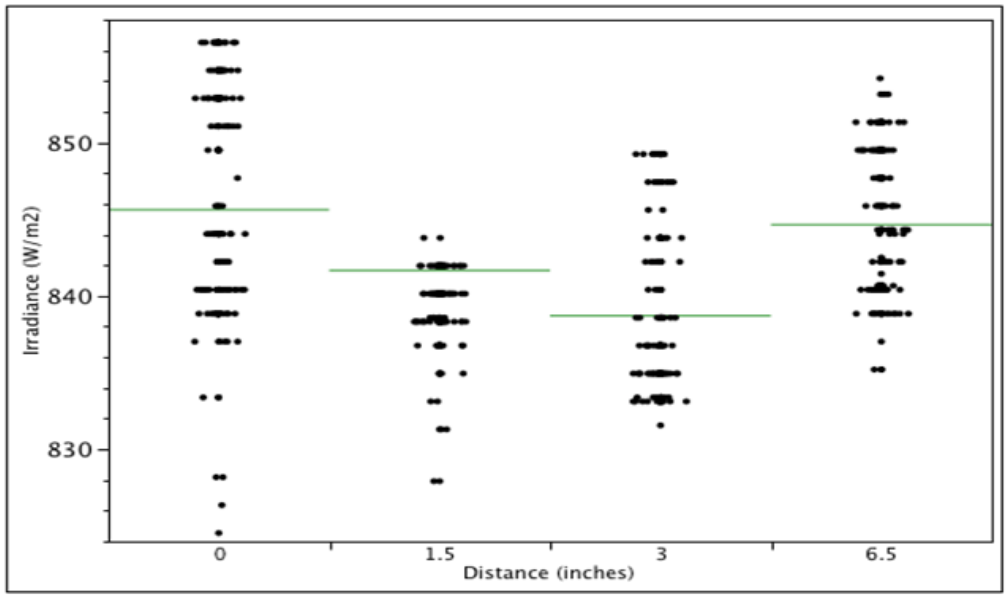


Figure 5. Influence of distance between screen (S-800) and irradiance sensor using a 1-inch by 1-inch reference cell (due to higher sensitivity of small area cell to screen spatial uniformity, we chose the 1-inch by 1-inch cells for this experiment).

Table 4

Percent Transmittance Calibration of Mesh Screens Using 1-inch by 1-inch Reference Cells

(screen distance from reference cell = 6.5 inches)

Screen code	Average irradiance under the screen (W/m^2)	Average irradiance outside the screen (W/m^2)	% Transmission	Standard deviation
S-100	156.16	1074.25	14.54	1.44 %
S-200	178.27	1063.55	16.76	2.65 %
S-400	468.15	1067.46	43.86	0.80 %
S-600	618.01	1075.50	57.46	0.50 %
S-800	871.58	1086.10	80.25	0.56 %

P_{max} Matrix Generation

Based on the results presented above, we expect the worst-case repeatability issue to occur when the screen is placed directly on the test module surface (0-inch air gap) and on the 1-inch by 1-inch reference cell surface (0-inch air gap). Table 5 shows the influence of this worst-case setup on the repeatability of performance (P_{max}) data for three runs. We obtained three runs of data that spanned more than 75 days between May 16, 2009, and July 30, 2009. The P_{max} data obtained in 2010 with the best-case setup (reference cell kept outside the screen and the test module kept at a minimum distance of 1.5 inches from the screen) are presented in the next section (Round Two Measurements). As shown in Table 2, all the measurements were carried out at air mass levels less than 2.5 and matched reference cell technologies to minimize the spectral mismatch error (Lad, 2010).

Note that the IEC 61853-1 standard specifies P_{max} data requirements only at 23 different test conditions (not 28 test conditions) in the seven by four matrix as shown in Table 1. In this report, the P_{max} data are reported (Table 5) only for 18 different test conditions, because the 2009 test setup was not designed to obtain the test data at either 15°C or 75°C. The goal in round one tests was to identify the measurement repeatability issues related to the test setup only, without the influence of errors related to the current-voltage translation or interpolation procedures. In order to minimize the errors related to translations/interpolations, we used the irradiance-specific temperature coefficients shown in the Appendix (Table A1), and the temperature and irradiance conditions during the tests were maintained very close (within +/- 2°C and 50 W/m^2) to the reporting conditions of 20, 25, and 45°C and 100, 200, 400, 600, 800, 1000, and 1100 W/m^2.

The extent of measurement repeatability issue, among the three runs shown in Table 5, was determined using standard deviations presented in Figure 6 (A,B,C,D). For all the four technologies tested, the standard deviation was found to be less than one watt for all but two data points (2 out of 72 data points). Unfortunately, only three runs were available for this standard deviation calculation. The measurement repeatability of the three runs was also determined from the maximum P_{max} deviation over the average—(highest P_{max}-lowest P_{max})/Average P_{max}—and Figure 7 (A,B,C,D) shows the repeatability data (% P_{max} deviation from average). The % P_{max} deviation obtained using the worst-case setup (0-inch air gap and reference cell kept under the screen) is higher (as high as 6%) than the acceptable limit of 1-2%. Due to time limitations, the entire repeatability study with the best-case setup (2-inch air gap and reference cell kept outside the screen) could not be performed for the second time. However, based on the results presented in Table 3 and Figure 5 above, the repeatability of measurements using the best case setup (2-inch air gap and reference cell kept outside the screen) are expected to be much better. The results obtained using the best-case setup are presented in the next section, Round Two Measurements.

TABLE 5

Pmax Measurement Repeatability for Four PV Module Technologies
at Different Temperatures and Irradiance Levels

(data obtained at 0-inch air gap between uncalibrated screen and test module and reference cell)

Mono-Si
(Zero inch air gap between uncalibrated screen and module / reference cell)

	20°C			25°C			45°C		
W/m²	Run1	Run2	Run3	Run1	Run2	Run3	Run1	Run2	Run3
1100	NA	NA	NA	179.02	178.52	177.46	160.26	158.61	158.35
1000	167.21	166.78	165.71	162.89	161.66	161.20	145.59	143.77	143.97
800	129.48	131.90	132.08	127.16	128.50	128.37	114.78	115.52	115.73
600	100.74	100.39	101.01	98.29	98.11	98.09	87.52	85.89	87.87
400	64.10	64.67	65.53	62.25	62.52	64.15	55.76	58.13	58.58
200	30.79	31.05	31.55	30.24	29.96	30.34	26.47	27.29	27.06
100	13.86	14.13	14.20	13.61	13.67	13.94	12.43	12.94	12.80

CIGS
(Zero inch air gap between uncalibrated screen and module / reference cell)

	20°C			25°C			45°C		
W/m²	Run1	Run2	Run3	Run1	Run2	Run3	Run1	Run2	Run3
1100	NA	NA	NA	29.94	30.20	30.26	31.49	31.78	31.52
1000	27.36	26.78	26.95	28.40	27.19	27.49	29.99	28.68	28.60
800	21.84	21.02	21.46	22.36	21.94	22.33	24.15	23.43	23.66
600	17.26	16.78	17.16	17.78	17.34	17.72	18.62	18.21	18.26
400	12.42	11.81	12.07	12.47	12.22	12.18	12.44	12.04	11.93
200	6.15	6.44	6.53	5.98	6.56	6.42	5.73	5.94	5.88
100	3.18	3.25	3.15	3.18	3.20	3.13	3.14	3.03	3.04

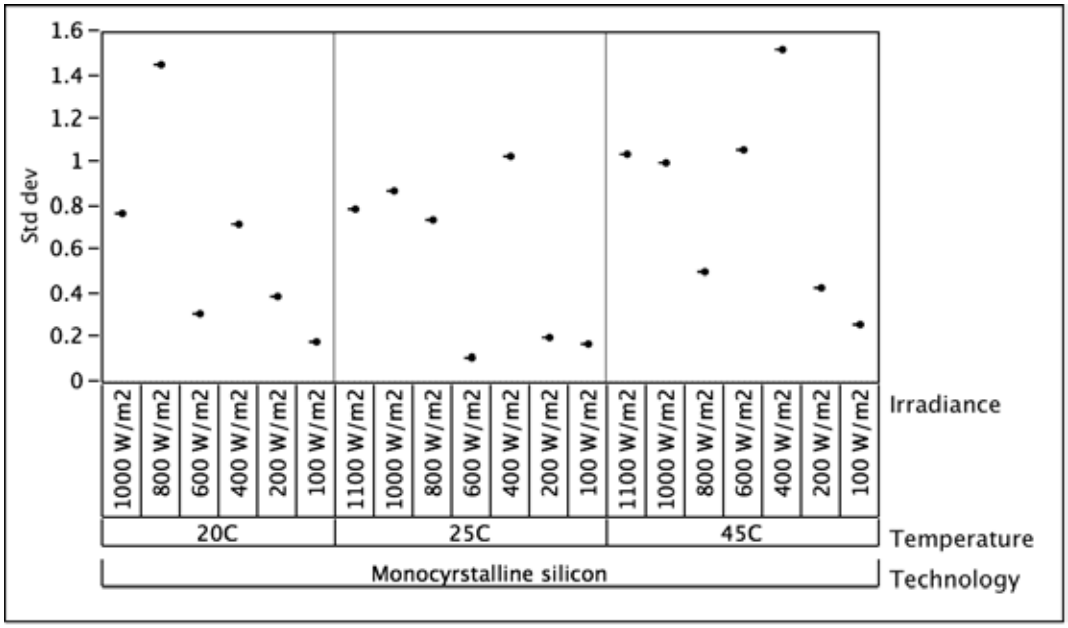
a-Si
(Zero inch air gap between uncalibrated screen and module / reference cell)

	20°C			25°C			45°C		
W/m²	Run1	Run2	Run3	Run1	Run2	Run3	Run1	Run2	Run3
1100	NA	NA	NA	39.13	40.65	40.96	37.40	38.79	38.76
1000	36.08	37.28	37.56	35.59	36.96	37.25	33.96	35.21	35.22
800	28.11	28.89	29.58	27.76	28.67	29.00	26.33	27.14	26.70
600	21.57	21.66	21.59	21.34	21.34	21.18	20.46	20.06	19.53
400	13.86	14.03	13.64	13.60	13.64	13.32	12.34	12.18	12.51
200	5.71	5.59	5.65	5.55	5.56	5.49	5.20	5.20	5.01
100	2.56	2.60	2.49	2.46	2.54	2.46	2.20	2.30	2.30

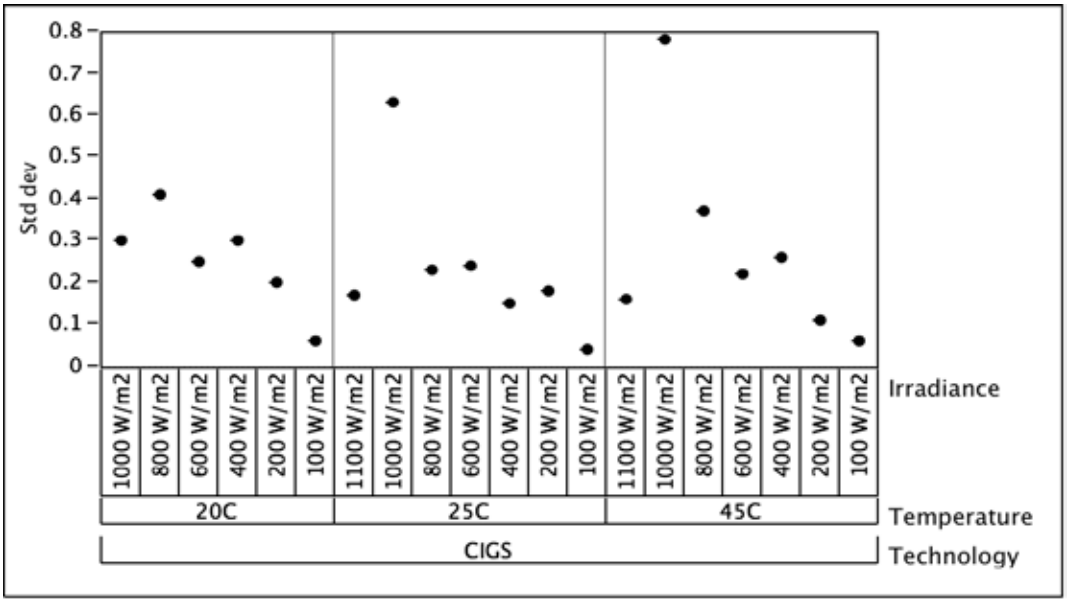
CdTe
(Zero inch air gap between uncalibrated screen and module / reference cell)

	20°C			25°C			45°C		
W/m²	Run1	Run2	Run3	Run1	Run2	Run3	Run1	Run2	Run3
1100	NA	NA	NA	74.47	75.29	74.83	71.48	72.15	71.90
1000	68.47	69.20	68.66	67.72	68.46	68.06	64.95	65.52	65.33
800	55.39	54.69	54.90	54.96	54.26	54.45	52.58	51.89	51.81
600	21.57	21.66	21.59	21.34	21.34	21.18	20.46	20.06	19.53
400	13.86	14.03	13.64	13.60	13.64	13.32	12.34	12.18	12.51
200	5.71	5.59	5.65	5.55	5.56	5.49	5.20	5.20	5.01
100	2.56	2.60	2.49	2.46	2.54	2.46	2.20	2.30	2.30

A: Mono-Si

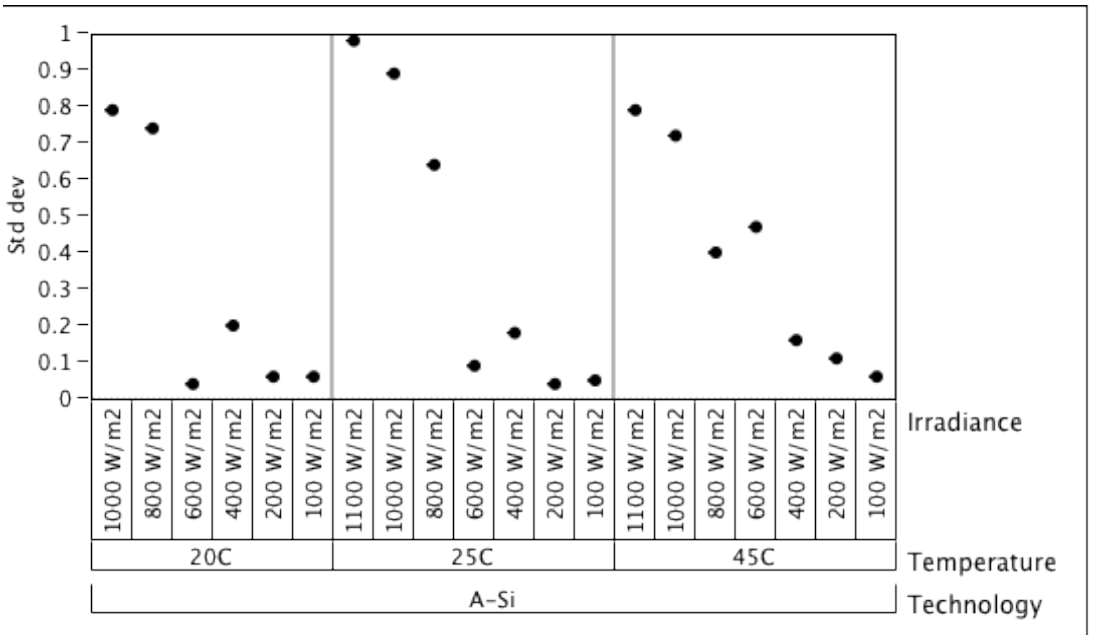


B: CIGS

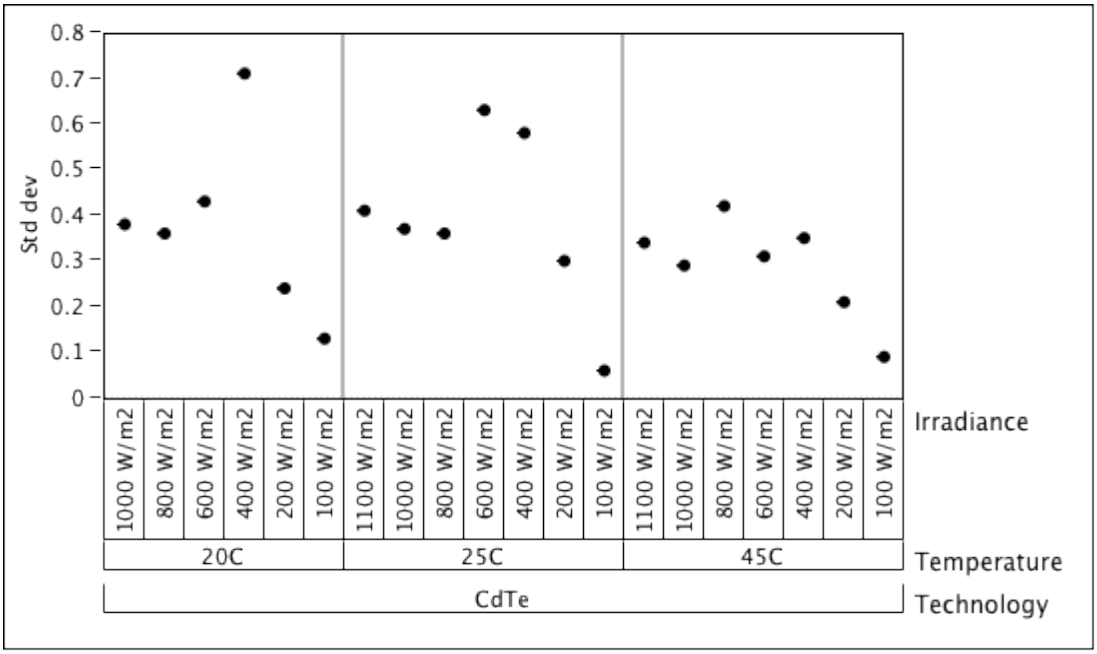


Figures 6A and 6B. Measurement repeatability of P_{max} over three runs (standard deviation in watts).

C: Amorphous-Si

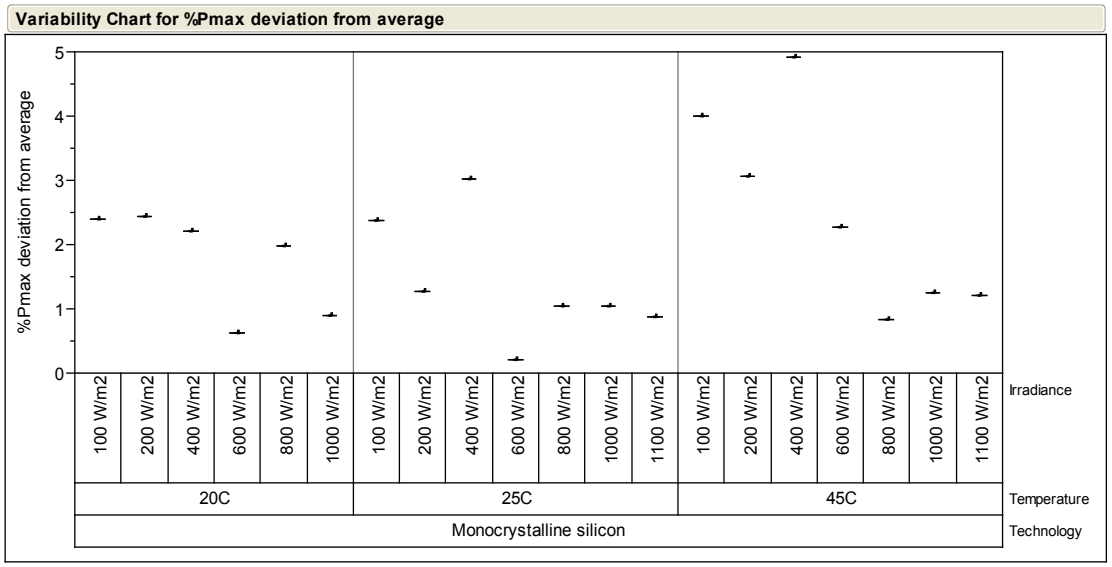


D: CdTe

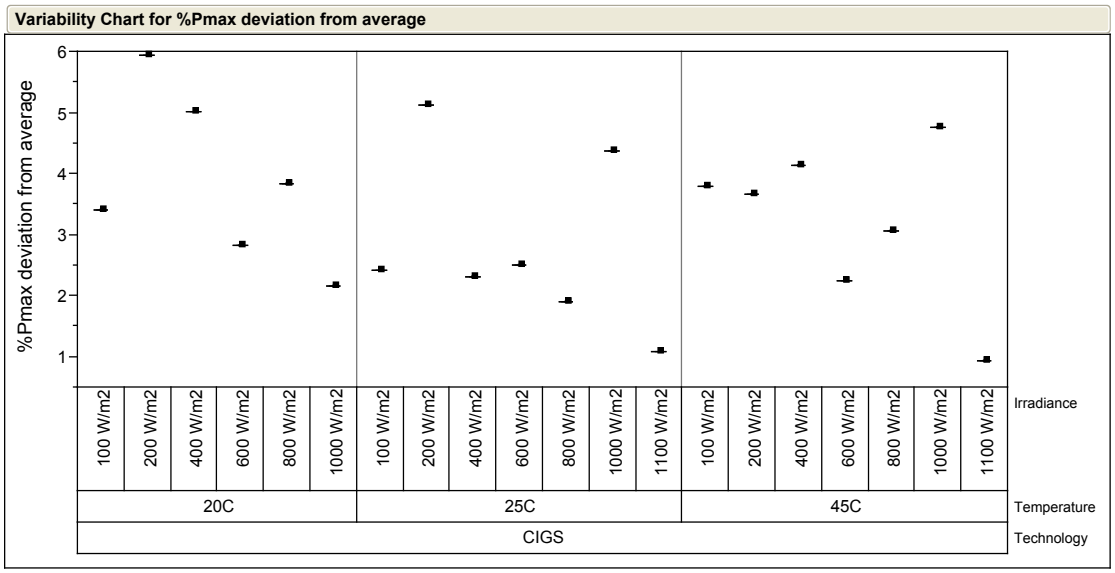


Figures 6C and 6D. Measurement repeatability of P_{max} over three runs (standard deviation in watts).

A: Mono-Si

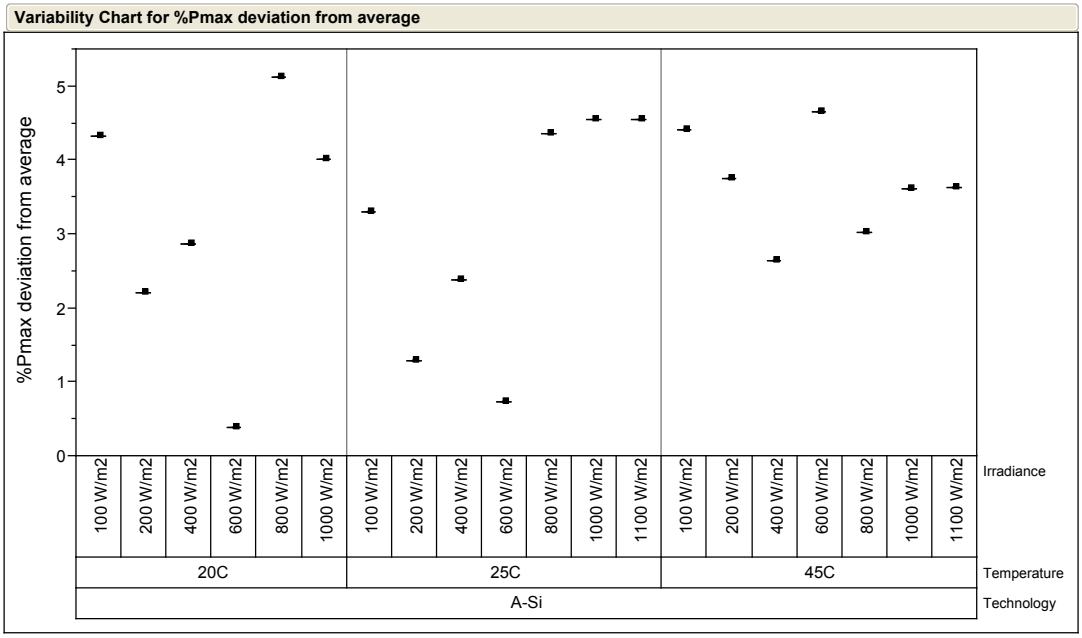


B: CIGS

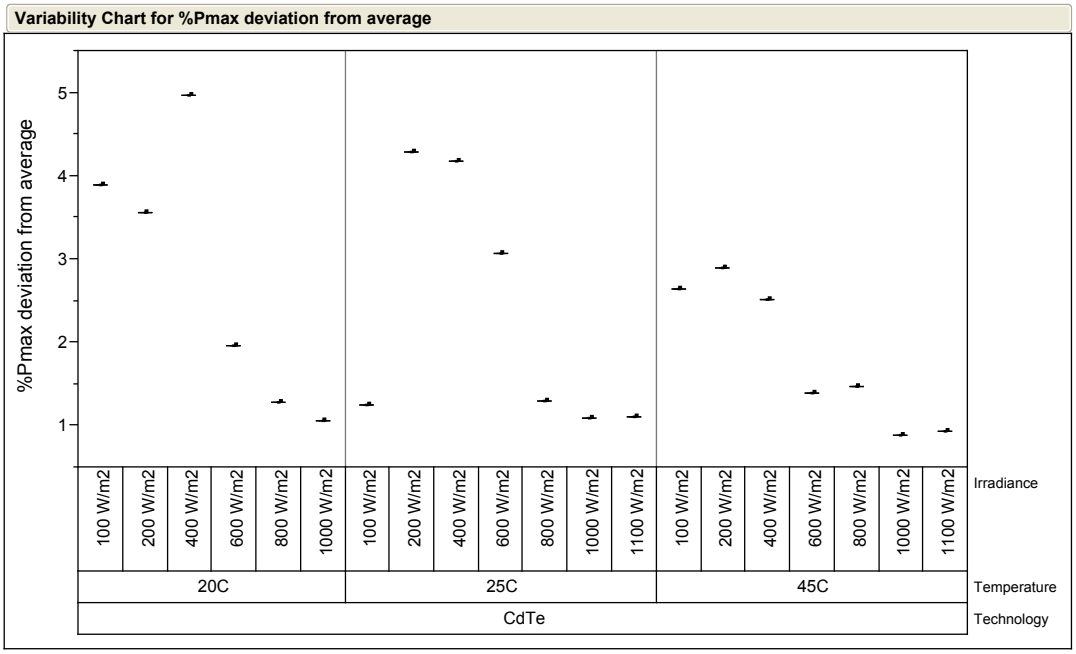


Figures 7A and 7B. Measurement repeatability of P_{max} over three runs (maximum P_{max} deviation from average).

C: Amorphous-Si



D: CdTe



Figures 7C and 7D. Measurement repeatability of P_{max} over three runs (maximum P_{max} deviation from average).

Round Two Measurements (2010)

Measurements With Standardized Test Setup

In the standardized test setup, the reference cells were placed outside the calibrated mesh screen and there was a 2-inch air gap between the module surface and the mesh screen. This setup has two major advantages—the measurements are more accurate and the measurements are repeatable. However, this setup requires calibration and rigid framing of mesh screens.

Light Transmittance of Calibrated Mesh Screens

Because most commercial reference cells are small area cells (typically less than 1 square inch), the light transmittance data (or the irradiance data) is very sensitive (as demonstrated in the round one measurements) to the spatial non-uniformity of the uncalibrated screens. Therefore, we suggest using only transmittance-calibrated screens. The transmittance calibration of the screens can be achieved using PV modules composed of large area cells.

In round two measurements, we used the short-circuit current values of the modules composed of large cells, per IEC 61853-1, to calibrate the screens for light transmittance. We used five crystalline silicon commercial modules from two different manufacturers for this screen calibration study. We assumed that each cell of the module generates an equal current. To gain confidence in this assumption, we used the average transmission of five modules instead of just one module.

Table 6 shows the transmittance values we obtained using five large area modules with a 2-inch air gap. By comparing the average transmission values and the standard deviation values between Table 3 and Table 6, it is clear that the light transmission is overestimated and the standard deviations are higher when a small reference cell-based irradiance sensor is used under the screens. As shown in column 4 [(Max-Min)/Max] of Table 6, the transmittance measurements become very sensitive for the irradiance levels below 200 W/m^2. To gain a higher level of confidence in the transmission calibration of the screens, it may be necessary to measure the Isc value of each and every cell of a large size module (preferably, a module composed of current matched cells), but it requires an intrusive technique to cut the backskin and access the individual cells.

Table 6

Percent Transmittance Calibration of Mesh Screens Using Large Commercial Modules
(screen distance from module = 2 inches)

Screen code	Transmittance (%)					Average transmission (%)	(Max-Min)/Max (%)	Std. dev.
	Module 1	Module 2	Module 3	Module 4	Module 5			
S-100	9.63	9.62	9.73	9.75	9.77	9.70	1.5%	0.72%
S-200	15.94	15.92	15.86	16.04	15.98	15.95	1.1%	0.44%
S-400	41.97	41.92	42.16	42.11	41.99	42.03	0.6%	0.24%
S-600	55.73	55.90	56.40	56.27	56.07	56.07	1.2%	0.48%
S-800	76.49	76.40	76.58	76.70	76.52	76.54	0.4%	0.14%

Linearity of Test Modules With Temperature and Irradiance

The test modules can be classified as linear or non-linear devices. A PV device is declared to be linear if the linearity requirements of IEC 60904-10 (clause 7.3) are met. If the device is not linear, then the measurements at or close to (within 100 W/m^2) all the 23 sets of conditions in Table 1 shall be carried out. The translation procedures of IEC 60891 or NREL Method may be used to translate from the actual measured condition to the reporting conditions of Table 1. If the "Simplified Procedure" of IEC 61853-1 (clause 8.2) is used, then the device must meet the additional linearity requirements of IEC 61853-1. If the linearity requirements of both IEC 60904-10 and IEC 61853-1 standards are met, then I-V measurements made at about 13 test conditions of Table 7 are sufficient to fill the 23 data points of Table 1 just by using the performance parameter measured at a single temperature with multiple irradiance levels and the temperature coefficient of the respective performance parameter.

TABLE 7

Required Test Conditions for Simplified Procedure of IEC 61853-1

Approximate irradiance (W/m^2)	**Approximate** module temperature (°C)				
	15	25	50	75	Equilibrium module temperature under prevailing outdoor condition (for example, 58°C)
1100	NA	NA	NA	NA	1
1000	6	7	8	9	2
800	NA	NA	NA	NA	NA
600	NA	NA	NA	NA	NA
400	NA	NA	NA	NA	3
200	10	11	12	13	4
100	NA	NA	NA	NA	5

For the ease of reference, the linearity requirements of IEC 60904-10 (clause 7.3) and IEC 61853-1 (clause 8.2) are reproduced below:

IEC 60904-10 requirements for device linearity:

"When a given device is claimed to be linear, the applicable range of temperatures, irradiance, voltage, or other necessary conditions shall also be stated. The requirements for the acceptable limits of non-linearity (variation) are:

a) For the curve of short-circuit current versus irradiance, the maximum deviation from linearity should be less than 2 %; b) For the curve of open-circuit voltage versus the logarithm of irradiance, the maximum deviation from linearity should be less than 5 %; c) For the curve of open-circuit voltage, short-circuit current and maximum power versus temperature, the maximum deviation from linearity should be less than 5 %. If the temperature coefficient of short circuit current is less than 0.1 %/K, the device can be considered linear with respect to this parameter."

Additional device linearity requirements of IEC 61853-1 for "Simplified Procedure":

"For some modules that are known to be linear (per IEC 60904-10), the maximum power dependence on irradiance and the maximum power dependence on temperature are independent. In this case it is sufficient to measure:

a) the parameters (I_{sc}, V_{oc}, P_{max} and V_{max}) dependence on irradiance at fixed temperature over the range of 100 W/m^2 to 1 100 W/m^2;b) The parameters (I_{sc}, V_{oc}, P_{max} and V_{max}) dependence on temperature at two fixed irradiances, one of which is between 800 W/m^2 and 1 000 W/m^2 and the second of which is between 100 W/m^2 to 300 W/m^2.

Compare the relative temperature coefficients for maximum power and open circuit voltage determined from the two irradiance sets. If the two values for the relative temperature coefficient of open circuit voltage agree within 10 % and the two values for the relative temperature coefficient of maximum power agree within 15 %, the average of the two temperature coefficients measured in b above can be utilized to fill out the tables. If not the table should be completed by measuring at each set of conditions."

For the ease of experimental setup planning, a suggested measurement sequence is shown by numbers: 1 through 23 in Table 1 and 1 through 13 in Table 7. Based on these 13 data points and the average temperature coefficient obtained at two irradiance levels as per clause 8.2b of IEC 61853-1 (for example, at approximately 1000 W/m^2 and 200 W/m^2 as shown in Table 7), all the 23 data points required at 23 exact sets of irradiance and temperature conditions of Table 1 can be filled using the simplified procedure.

As indicated in Table 8, none of the four test modules is qualified for the use of simplified procedure because they all fail to meet the stringent IEC 61853-1 linearity requirements. As a result, we have only used the four translation procedures of IEC 60891 and NREL Method in this work. All the test modules were also verified for the linearity requirements as per IEC 60904-10 using wide ranges of temperature (15 to 75°C) and irradiance (100 to 1100 W/m^2). Figures 8A and 8B show the results. As presented in the summary of Table 9 for mono-Si and of Table 2A through 4A in the Appendix for the other three technologies, all the modules meet all the linearity requirements of P_{max}, V_{oc}, and I_{sc} with respect to temperature (except a-Si at 50°C, which is apparently due to slight experimental error because this device meets the requirement above and below 50°C). These tables also indicate that all these devices meet the linearity requirements of V_{oc} with respect to irradiance, except at 1100 W/m^2 for CIGS and at 600 W/m^2 for a-Si. (We suspect that the data at 600 W/m^2 for a-Si is a slight experimental or processing error, because the linearity requirements of this device are met at above and below 600 W/m^2. The data at 1100 W/m^2 for CIGS could be a real device issue due to series resistance or a slight experimental/processing error.)

For the short-circuit current versus irradiance, the devices practically met the linearity requirement (2 % deviation limit) for irradiance levels above 200 W/m^2 but they, surprisingly, showed a higher deviation (more than 5 %) for the irradiance levels below 200 W/m^2. As evidenced from the screen transmittance calibration data presented in Table 6 [column 4: (Max-Min)/Max], this higher deviation could be attributed to some minor experimental errors related to the calibration of low transmittance mesh screens under natural sunlight. Moreover, for the thin-film technologies with already low I_{sc} values even at one sun irradiance, the 100 W/m^2 irradiance level becomes very sensitive for the I_{sc} determination as the current level approaches the sensitivity limit of the I-V curve tracer.

It is important to note that the IEC 61853-1 standard restricts the irradiance limit for the translation to 100 W/m^2 as per the following requirement: *"Measurements need not be taken at exactly the irradiances and temperatures specified. Translation of I-V curves from*

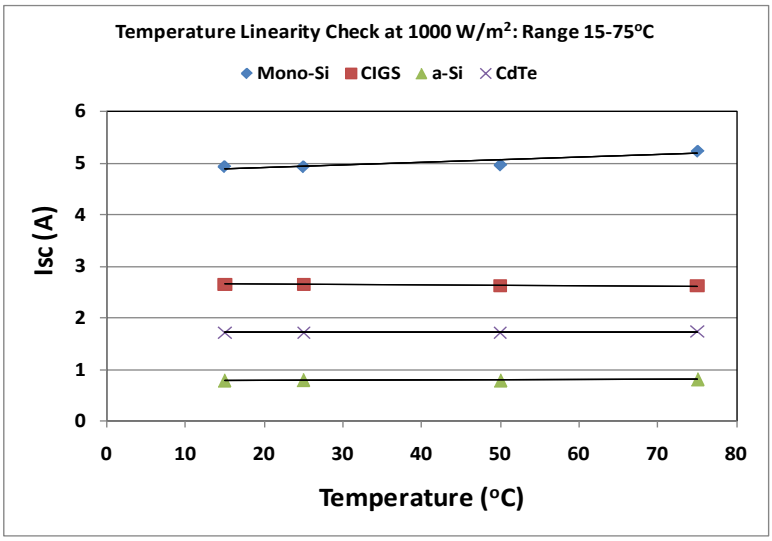
the actual irradiance and/or temperature values to the values prescribed by the tables can be performed in accordance with IEC 60891. Such interpolation should be over no more than 100 W/m².” Considering this 100 W/m² irradiance limit imposed by the IEC 61853-1 standard and that all the test devices have been demonstrated to be linear with respect to temperature, it may be stated that all the test devices of this work meet the linearity requirements for a wide range of temperature (15 to 75°C) and a narrow irradiance limit (< 100 W/m²).

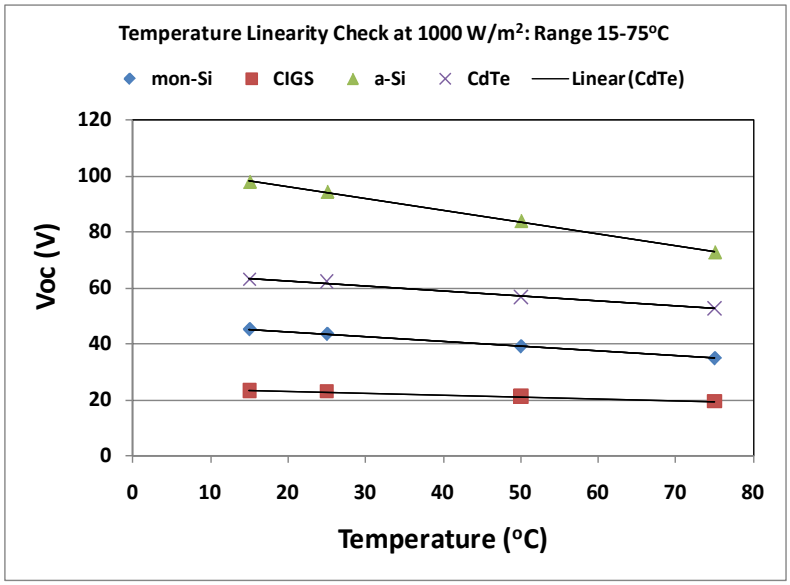
TABLE 8

Linearity Checking of Test Modules as per “Simplified Procedure” of IEC 61853-1

(the red highlighted data do not meet the linearity deviation limit)

	Mono-Si	CIGS	a-Si	CdTe
Difference between relative temperature coefficient at 1000 and 200 W/m² for P_{max} (allowed limit: < 15 %)	-13.2 %	-4.0 %	50.7 %	72.1 %
Difference between relative temperature coefficient at 1000 and 200 W/m² for V_{oc} (allowed limit: < 10 %)	-31.3 %	16.7 %	-11.8 %	-38.4 %





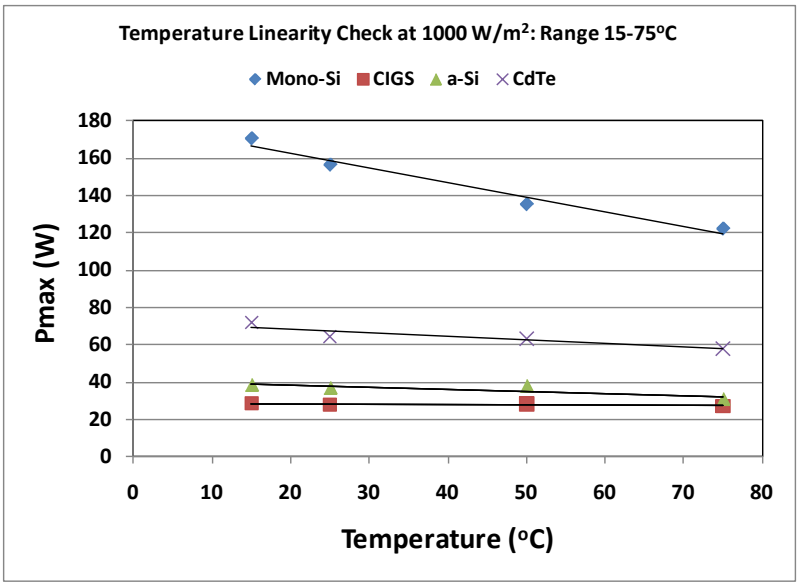
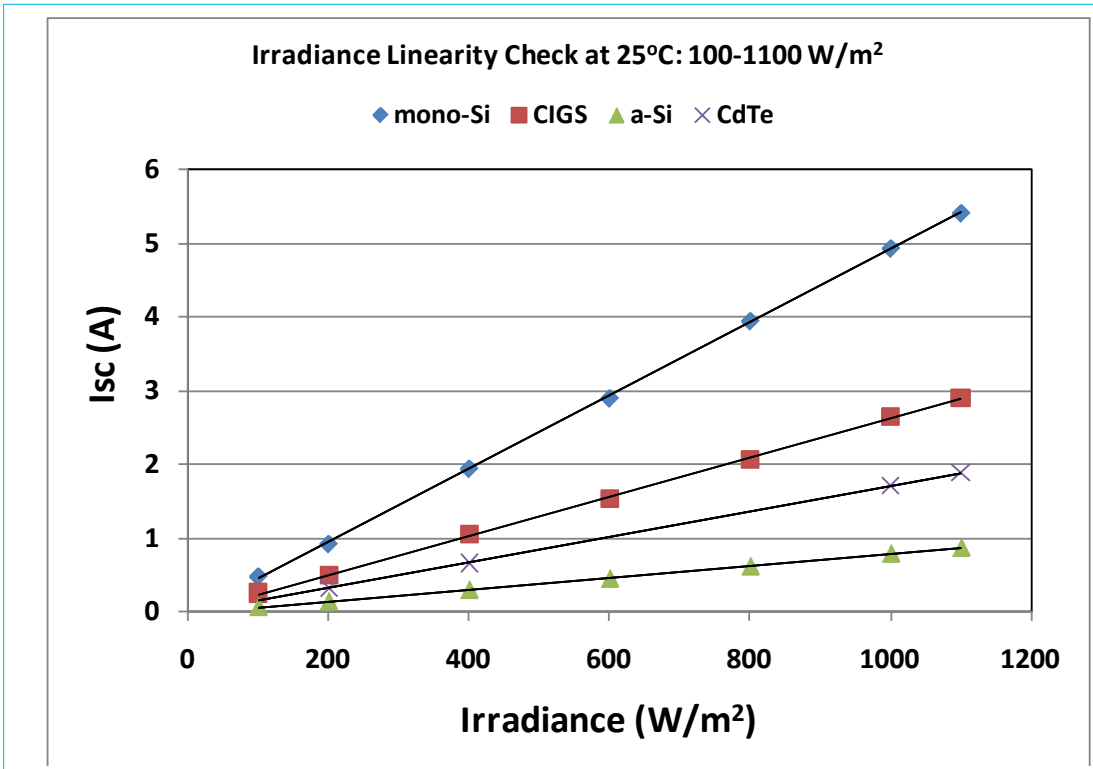


Figure 8A. Linearity checking of test modules for temperature as per IEC 60904-10.



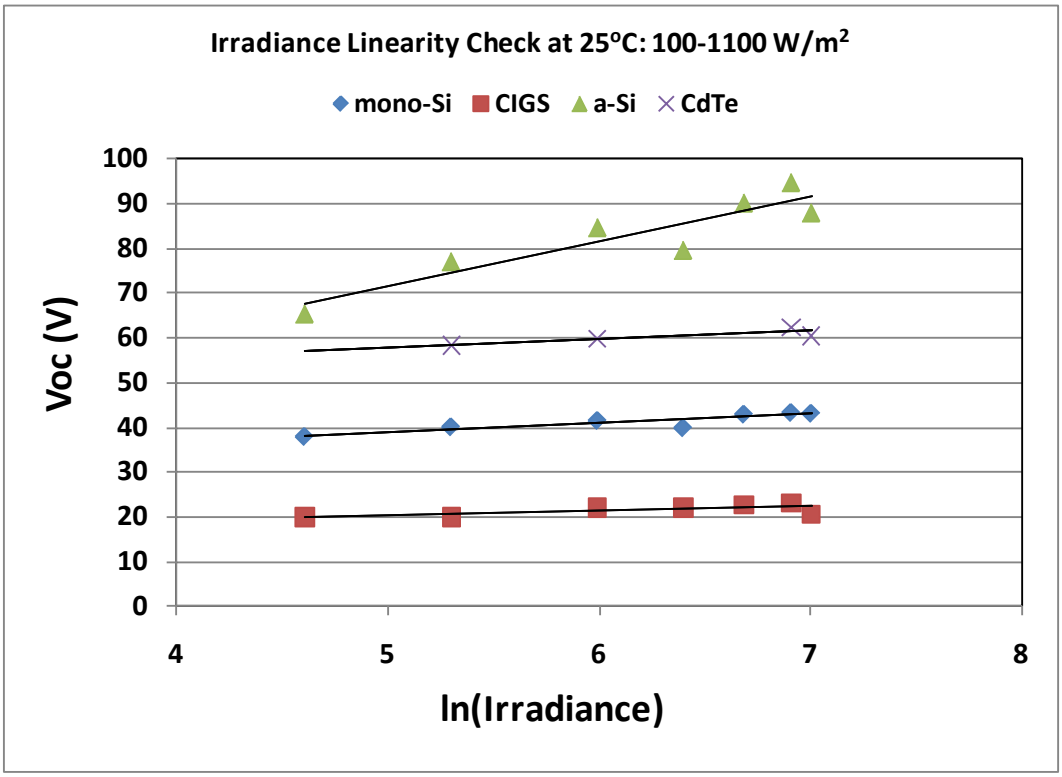


Figure 8B. Linearity checking of test modules for irradiance as per IEC 60904-10.

TABLE 9.

Linearity Checking of Test Modules as per IEC 60904-10

(the red highlighted data do not meet the linearity deviation limit)

Mono-Si	Linearity Deviation for Temperature (°C)			
	15	25	50	75
Linearity deviation of I_{sc} for temperature at 15-75°C temperature range and a single irradiance of 1000 W/m² (allowed limit: < 5 %)	-0.9 %	0.1 %	1.9 %	-1.1 %
Linearity deviation of V_{oc} for temperature at 15-75°C temperature range and a single irradiance of 1000 W/m² (allowed limit: < 5 %)	0.0 %	-0.1 %	0.2 %	-0.1 %
Linearity deviation of P_{max} for temperature at 15-75°C temperature range and a single irradiance of 1000 W/m² (allowed limit: < 5 %)	2.2 %	1.6 %	2.8 %	-2.3 %

Mono-Si	Linearity Deviation for Irradiance (W/m²)						
	1100	1000	800	600	400	200	100
Linearity deviation of I_{sc} for irradiance at 100-1100 W/m² irradiance range and a single temperature of 25°C (allowed limit: < 2 %)	1.0 %	0.7 %	0.4 %	2.1 % *	0.8 %	3.6 %	-5.6 %
Linearity deviation of V_{oc} for irradiance at 100-1100 W/m² irradiance range and a single temperature of 25°C (allowed limit: < 5 %)	-0.2 %	-1.0 %	-1.2 %	4.6 %	-1.3 %	-1.4 %	0.6 %
	* *Seems to be a slight experimental/processing error as the device meets the linearity requirement at above 600 W/m² and at 400 W/m² (or it can be neglected due to measurement uncertainty)*						

P_{max} Matrix Generation With Mesh Screen Placed 2 Inches Above Module Surface

The P_{max} matrix data for all the four module technologies were obtained using one of the four procedures (Procedure 1, 2, 3, or 4). The translation method of each procedure is briefly explained in the Appendix (Figures A3 and A4) (Marion et al., 2004) (IEC, 2009). This study required 8 to 23 reference I-V curves, depending on the procedure. The reference curves were obtained using calibrated screens, maintaining an optimum distance of 2 inches between screen and module surface, and keeping the reference cells outside the screens. Figure 9 shows the reference/measured conditions used for c-Si. Table 10 shows an example of P_{max} data obtained for mono-Si from actual measured conditions to reporting conditions of IEC 61853-1. The reference curves used for the other three technologies are shown in the Appendix (Figures A5 through Figures A7). Figure 10 shows the P_{max} matrix obtained for each of the four technologies using all the four procedures. The validation (translated vs. measured) of each procedure is presented in the next section.

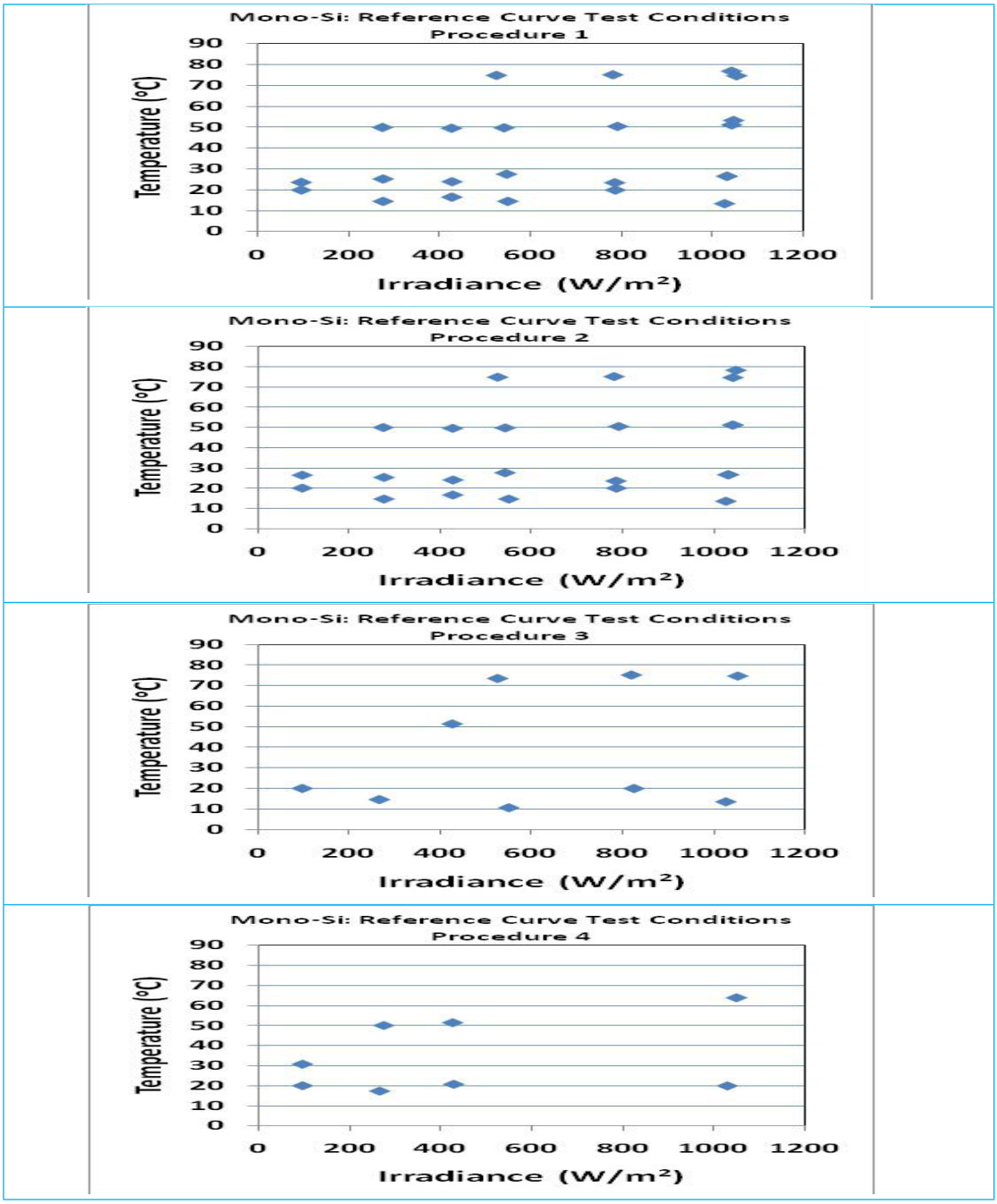


Figure 9. Test conditions used for c-Si to obtain reference curves for each procedure.

TABLE 10

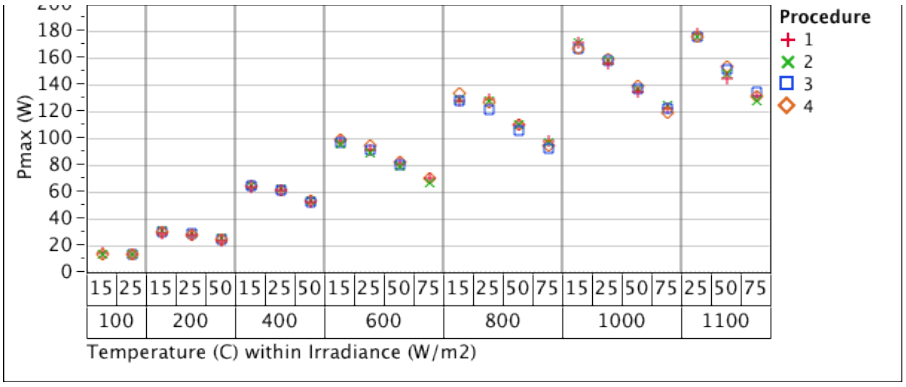
Example of P_{max} Data Obtained for Mono-Si From Actual Measured Conditions to Reporting Conditions of IEC 61853-1

Measured			Translated (Procedure)		
Irradiance (W/m^2)	Temp (°C)	P_{MAX} (W)	Irradiance (W/m^2)	Temp (°C)	P_{MAX} (W)
97	20.0	13.3	100	15	14.0
97	23.7	12.8	100	25	13.2
277	14.6	41.6	200	15	28.8
277	25.3	39.4	200	25	27.4
275	50.0	33.5	200	50	23.3
428	16.6	68.2	400	15	63.5
428	24.0	65.9	400	25	61.1
427	49.6	56.1	400	50	52.1
551	14.6	88.7	600	15	97.4
548	27.6	82.9	600	25	90.7
542	49.8	72.5	600	50	80.9
526	74.9	60.2	600	75	69.6
787	20.0	129.2	800	15	128.0
786	23.5	125.6	800	25	129.1
792	50.5	109.1	800	50	110.1
782	75.2	95.0	800	75	97.3
1027	13.5	173.7	1000	15	170.6
1032	26.6	162.8	1000	25	155.7
1043	51.2	142.2	1000	50	134.7
1054	74.7	128.9	1000	75	122.1
1032	26.6	167.9	1100	25	177.5
1046	53.3	140.5	1100	50	144.0
1042	76.9	126.5	1100	75	131.5

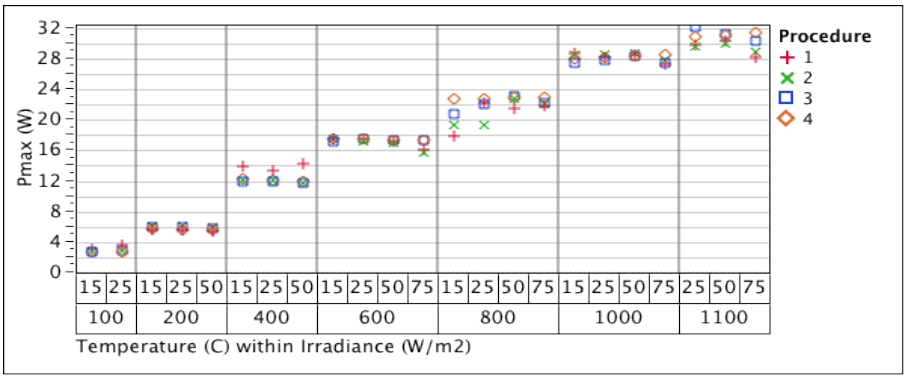
Measured irradiance is within 100 W/m^2 from target irradiance

Measured temperature is within 5°C from target temperature

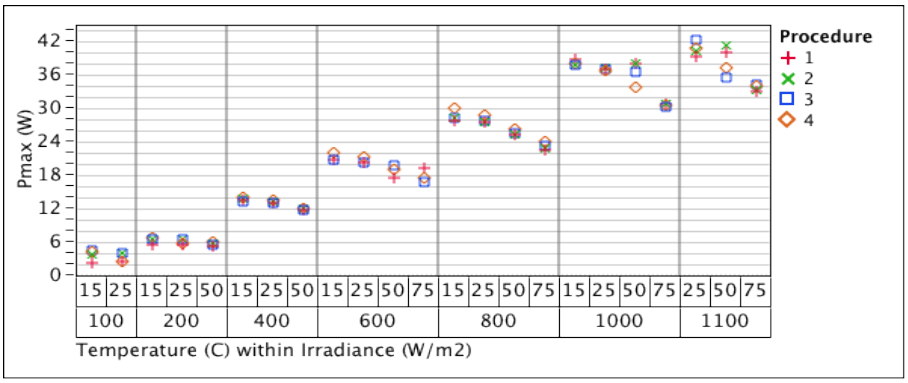
Pmax Matrix: Mono-Si



Pmax Matrix: CIGS



Pmax Matrix: a-Si



Pmax Matrix: CdTe

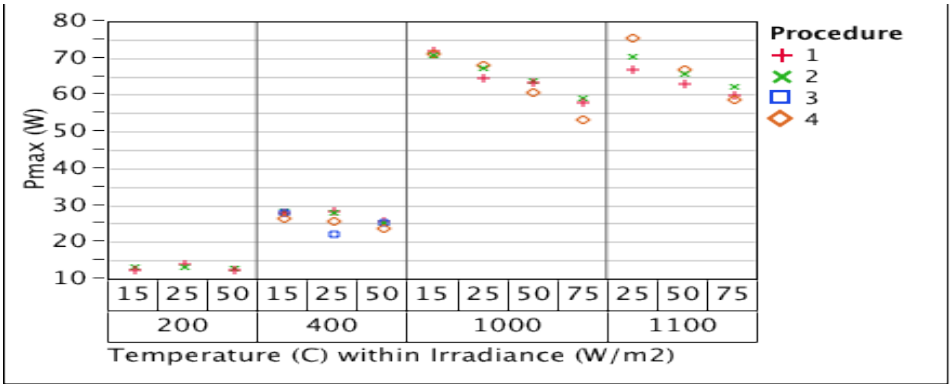


Figure 10. Pmax data of all four technologies at different temperatures and irradiance levels (Procedure-1: IEC60891; Procedure-2: IEC60891; Procedure-3: IEC60891; Procedure-4: NREL Method).

Validation of Current-Voltage Translation/Interpolation Procedures

The goal in using all four I-V curve translation and interpolation procedures is to fill up the 23-element performance matrix with the highest accuracy using the least number of measured/reference I-V curves. Procedure 1 requires the highest number of reference curves (as high as 23 curves) as the allowed irradiance deviation from target curves is less than 20%. Procedures 3 and 4 require the least number of reference curves (as low as 3-4 curves). The required number of reference curves for Procedure 2 falls between these two extremes. The major disadvantage of Procedures 1 and 2 (translation procedures) is the accurate determination of correction factors. The issue related to the accurate determination of correction factors can be minimized if the data processing is completely automated or the measured curves are obtained closest to the 23 target curves. The major disadvantage of Procedures 3 and 4 (interpolation procedures) is the difficulty in accurately accounting for the fill factor change between high and low irradiance ranges. The issue related to the fill factor change can be minimized if two sets of reference curves are obtained (one set of 3 to 4 curves at low irradiance range and the other set of 3 to 4 curves at high irradiance range). In order to execute Procedures 1 and 2, it is necessary to determine the correction parameters (see Figure A3 in the Appendix). It may be necessary to make a comment on the determination of proper single value for each of the correction parameters (a, Rs, or k) for the translation from any measured (reference) irradiance-temperature condition to any other measured (target) irradiance-temperature condition.

For the determination of proper value, the standard (IEC 60891) requires that the P_{max} deviation between reference and target curves shall be within 0.5%. It is possible to meet this requirement if the best fit individual correction value is used for each reference test condition rather than a single value for all the reference conditions (or use multiple narrow translation ranges rather than a single large translation range)

In order to determine the accuracy of each of these four translations and interpolation procedures, the validation approach used by NREL Method was adopted in this work (Marion et al., 2004). Because the translation and interpolation procedures are more sensitive to the irradiance ranges than to the temperature ranges, the sensitivity of each translation procedure was verified at four irradiance ranges (approximate): A (within 1% of target irradiance), B (400-1000 W/m^2), C (100-400 W/m^2), and D (600-1000 W/m^2). We selected a large number of measured curves for this validation work. Some of the selected curves were treated as reference curves and the others were treated as target curves. As an example, 25 measured curves of mono-Si module were selected for the validation Procedure 4B (see Table 11). Out of these 25 measured curves, eight curves were treated as reference curves and the other 17 curves were treated as target curves.

The temperature and irradiance ranges of the target curves of only two technologies (mono-Si and CIGS) are presented in Table 11 as examples. The validation results of each procedure for P_{max} are provided in Figure 11A (average error in %) and Figure 11B (RMSE in %). Because the irradiances of reference and target curves of Procedures 1A and 2A are within 1%, they are expected (and found) to be very accurate as evidenced in Figures 11A and 11B. As shown in Figure 11, all the ranges (A, B, C, and D) in all the procedures agree with each other and are within about a 3% average error from the actual measured data. As suspected, among all the irradiance ranges considered, the low irradiance range (100 to 400 W/m^2) in all the four procedures tend to have the highest average error. The meta-stable nature of the thin-film technologies may also contribute to the errors for a-Si, CdTe, and CIGS technologies. We concluded that the general agreement between the translated/interpolated P_{max} data and the actual measured data for all four module technologies (within 3% average error) is remarkably good.

Table 11

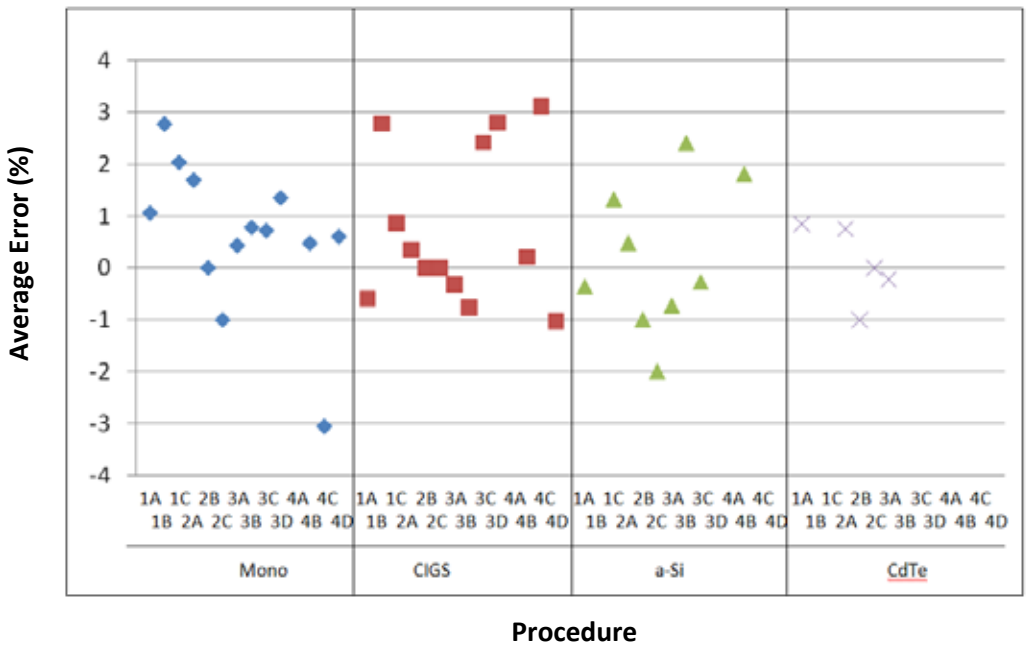
Irradiance and Temperature Ranges of Target I-V curves
Used for the Validation of Four Procedures

Procedure 1	Procedure 2	Procedure 3	Procedure 4
Number of reference I-V curves used = 23	Number of reference I-V curves used = 5-21	Number of reference I-V curves used = 9	Number of reference I-V curves used = 8
Data 1: Target & reference irradiance difference (%); Data 2: Target & reference temperature difference (°C); *Data 3: Number of target I-V curves used for validation; Data 4: Irradiance range/limit of target I-V curves used for translation or interpolation (W/m²)*			
Mono-Si			
Procedure 1A: 0.1 %; 4°C; 26 I-Vs; Irrad. range not applic.	Procedure 2A: < 1 %; < 4°C; 26 I-Vs; Irrad. range not applic.	Procedure 3A: NA; < 10°C; 17 I-Vs; < 200 W/m²	Procedure 4A: NA
Procedure 1B: < 25 %; 6°C; 6 I-Vs; 426-1054 W/m²	Procedure 2B: < 31 %; < 4°C; 13 I-Vs; 428-1054 W/m²	Procedure 3B: NA; 9-74°C; 14 I-Vs; 428-1029 W/m²	Procedure 4B: NA; 20-64°C; 17 I-Vs; 426-1050 W/m²
Procedure 1C: < 37 %; 6°C; 10 I-Vs; 97-428 W/m²	Procedure 2C: < 37 %; < 4°C; 7 I-Vs; 266-429 W/m²	Procedure 3C: NA; 9-51°C; 6 I-Vs; 97-528 W/m²	Procedure 4C: NA; 17-50°C; 9 I-Vs; 97-275 W/m²
Procedure 1D: Not applicable (NA)	Procedure 2D: Not applicable	Procedure 3D: NA; 14-75°C; 6 I-Vs; 526-1051 W/m²	Procedure 4D: NA; 14-58°C; 11 I-Vs; 542-1046 W/m²
CIGS			
Procedure 1A: 0.4 %; 3°C; 12 I-Vs; Irrad. range not applic.	Procedure 2A: < 4 %; < 4°C; 33 I-Vs; Irrad. range not applic.	Procedure 3A: NA; < 10°C; 17 I-Vs; < 200 W/m²	Procedure 4A: NA
Procedure 1B: < 28 %; 4°C; 6 I-Vs; 429-793 W/m²	Procedure 2B: < 28 %; < 4°C; 13 I-Vs; 429-798 W/m²	Procedure 3B: NA; 9-51°C; 6 I-Vs; 432-1034 W/m²	Procedure 4B: NA; 11-75°C; 17 I-Vs; 432-1034 W/m²
Procedure 1C: < 39 %; 3°C; 9 I-Vs; 262-433 W/m²	Procedure 2C: < 39 %; < 4°C; 7 I-Vs; 262-432 W/m²	Procedure 3C: NA; 9-51°C; 6 I-Vs; 104-564 W/m²	Procedure 4C: NA; 17-50°C; 9 I-Vs; 104-564 W/m²
Procedure 1D: NA	Procedure 2D: Not applicable	Procedure 3D: NA; 9-45°C; 6 I-Vs; 566-1030 W/m²	Procedure 4D: NA; 9-45°C; 11 I-Vs; 566-1030 W/m²

a) Procedure Validation: % Error

TYPICAL TRANSLATION RANGE/LIMIT

A: Within 1% of target irradiance; B: 400-1000 W/m^2; C: 100-400 W/m^2 *(very sensitive range);* D: 600-1000 W/m^2



b) Procedure Validation: % RMSE

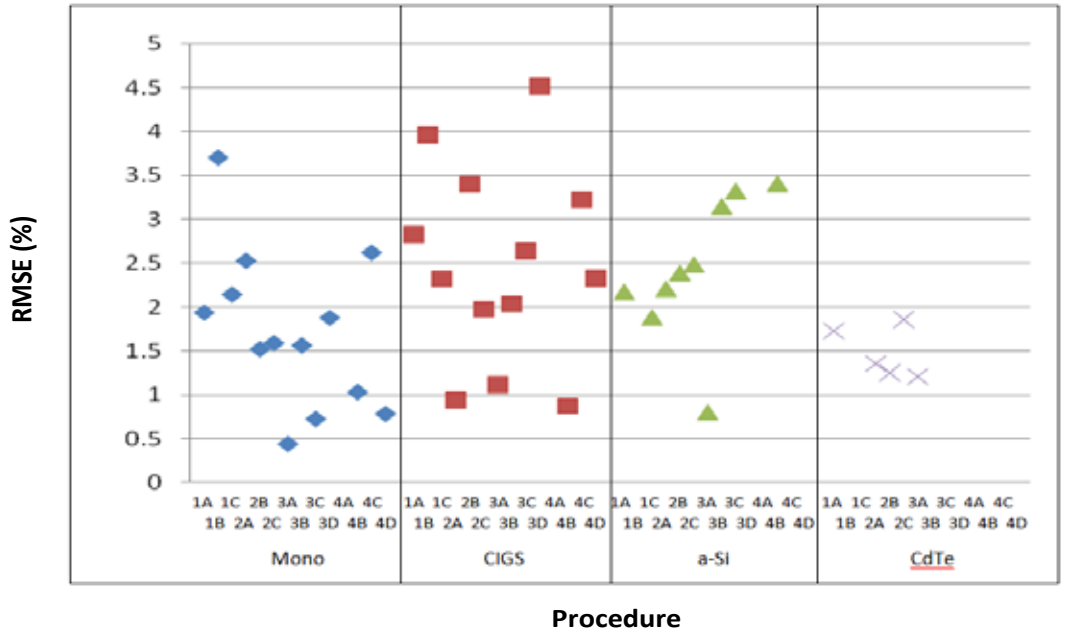


Figure 11a) Average (%). b) RMSE (%) errors of P_{max} of all four technologies at different temperature and irradiance ranges.

CONCLUSIONS

We carried out two rounds of power rating measurements. In the round one (2009) measurements, the distance between the screen and test module or small reference cell was kept at 0-inch distance. The round one measurements with 0-inch distance between test device and screen demonstrated that the P_{max} measurements are repeatable within only about 6 %—higher than the acceptable limit of 1 to 2 %. Based on the round one study, we conclude that the P_{max} matrix using natural sunlight can be acceptably repeated if:

- The measurements are carried out on clear sunny days when the air mass is less than 2.5.
- A matched reference cell technology is used to monitor the irradiance level.
- A calibrated mesh screen is used with the reference cell kept outside the screen.
- A minimum distance of 1.5 inch is maintained between the test module and the mesh screen.

In the round two (2010) measurements, the distance between the screen and test module was kept at a 2-inch distance and the reference cell was kept outside the screen. None of four technologies qualifies for the use of "Simplified Translation Procedure" of IEC 61853-1, because they all fail to meet the linearity requirement of IEC 61853-1. For I_{sc}, V_{oc}, and P_{max}, all four module technologies, excluding a-Si at 50°C, were determined to be linear, as per IEC 60904-10, with respect to temperature for a wide range of temperature (15 to 75°C). For V_{oc}, all four technologies, excluding CIGS at 1100 W/m^2 and a-Si at 600 W/m^2, were determined to be linear, as per IEC 60904-10, with respect to irradiance for a wide range of irradiance (100 to 1000 W/m^2). For the short-circuit current versus irradiance, the devices met the linearity requirement (2 % deviation limit) for irradiance levels above 200 W/m^2 but they surprisingly showed a higher deviation for the irradiance levels below 200 W/m^2. This higher deviation was evidently attributed to some minor experimental errors related to the calibration of low transmittance mesh screens under natural sunlight.

The required P_{max} matrix of IEC 61853-1 was successfully filled for all four module technologies using the four translation/interpolation procedures of IEC 60891 and NREL Method. With two narrow ranges of irradiance (typically 100 to 400 W/m^2 and 400 to 1100 W/m^2), all four procedures were validated using the measured reference and target I-V curves of all four technologies. The translation procedure validation work demonstrated that the translated/interpolated P_{max} data could be remarkably matched with the actual measured data for all of the procedures within an average error of about 3 %, provided these procedures were applied with a minimum of two ranges of irradiance (for example, 100 to 400 W/m^2 and 400 to 1100 W/m^2).

The Procedures 1 and 2 have the potential to lower the number of I-V measurements as compared to Procedures 3 and 4, but they require the determination of two temperature coefficients and up to three correction factors. The determination of proper correction parameters of Procedures 1 and 2 (translation procedures) for the 23 power rating conditions of IEC 61853-1 using a trial and error method would be very time consuming. Unless an extreme attention is paid or commercial test laboratories automate the data processing, the translation procedures (1 and 2) are more prone to human errors than the interpolation procedures (3 and 4). However, Procedures 1 and 2 would work extremely well if multiple narrow irradiance ranges are used with individual set of correction values for each narrow irradiance range or multiple/variable set of correction values are used for a single wide irradiance range.

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APPENDIX

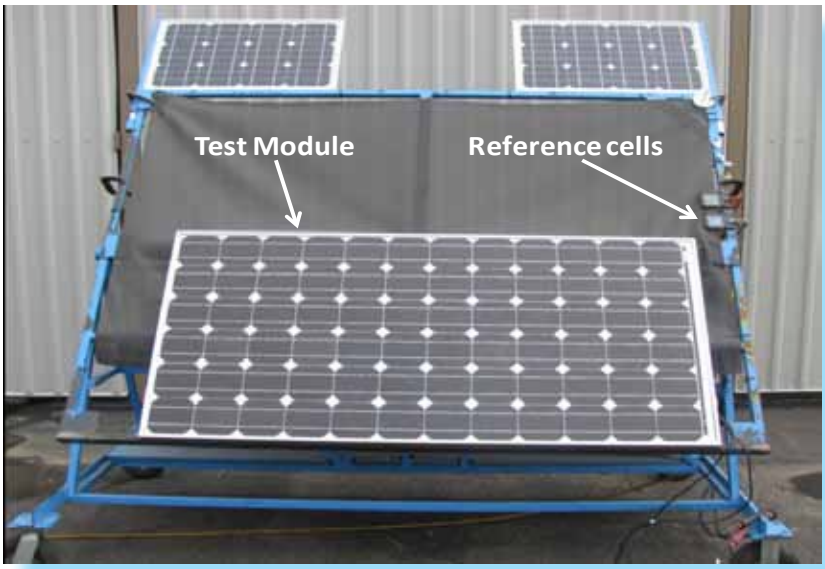


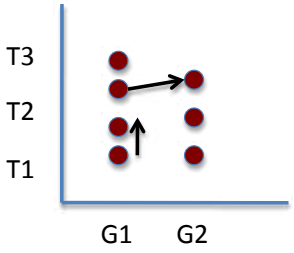
Figure A1. Outdoor performance measurements setup using a manual 2-axis tracker.

Screen Manufacturer: Phifer Incorporated Tuscaloosa Alabama	
Model Number of Manufacturers	**Screen Designation of ASU**
Sheer Weave (2100)	S-100
Shear Weave (3000)	S-200
Fiber Glass (20x20)	S-400
Fiber Glass (18x14)	S-600
Fiber Glass (Vent mesh)	S-800

Figure A2. Mesh screens (100"x50") used in this investigation.

IEC 60891:Procedure 1

$$I_2 = I_1 + I_{sc} (G_1/G_2 - 1) + \alpha (T_2-T_1)$$
$$V_2 = V_1 - R_s (I_2 - I_1) - \kappa I_2 (T_2-T_1) + \beta (T_2-T_1)$$



Procedures 1 and 2

Legend:

I_2 , V_2 = Target current and voltage
I_1, V_1 = Measured current and voltage
G_2, T_2 = Target irradiance and temperature
G_1, T_1 = Measured irradiance and temperature

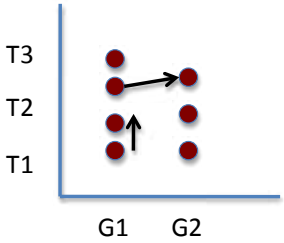
Module Parameters:

α = temp coeff I_{sc} (A/°C)
β = temp coeff V_{oc} (V/°C)
R_s = series resistance (Ω)
κ = curve correction factor (Ω/°C)

NOTE: Temperature coefficients, series resistance and curve correction parameters are required for this procedure. The difference between the measured and target irradiances should be within 20%.

IEC 60891:Procedure 2

$$I_2 = I_1 * (1 + \alpha_{rel} * (T_2 - T_1)) * G_2/G_1$$
$$V_2 = V_1 + V_{oc1} * (\beta_{rel} * (T_2 - T_1) + a * \ln (G_2/G_1)) - R'_s * (I_2 - I_1) - \kappa' * I_2 * (T_2 - T_1)$$



Procedures 1 and 2

Legend:

I_2 , V_2 = Target current and voltage
I_1, V_1 = Measured current and voltage
G_2, T_2 = Target irradiance and temperature
G_1, T_1 = Measured irradiance and temperature

Parameter constants of module

α_{rel} = relative temp coeff I_{sc} (1/°C)
β_{rel} = relative temp coeff V_{oc} (1/°C)
R'_s = series resistance (Ω)
κ' = curve correction factor (Ω/°C)
a = Irradiance correction factor

NOTE: Temperature coefficients, series resistance and curve & irradiance correction parameters are required for this procedure. The difference between measured and target irradiances can be higher than 20%.

Figure A3. IEC 60891—Procedures 1 and 2.

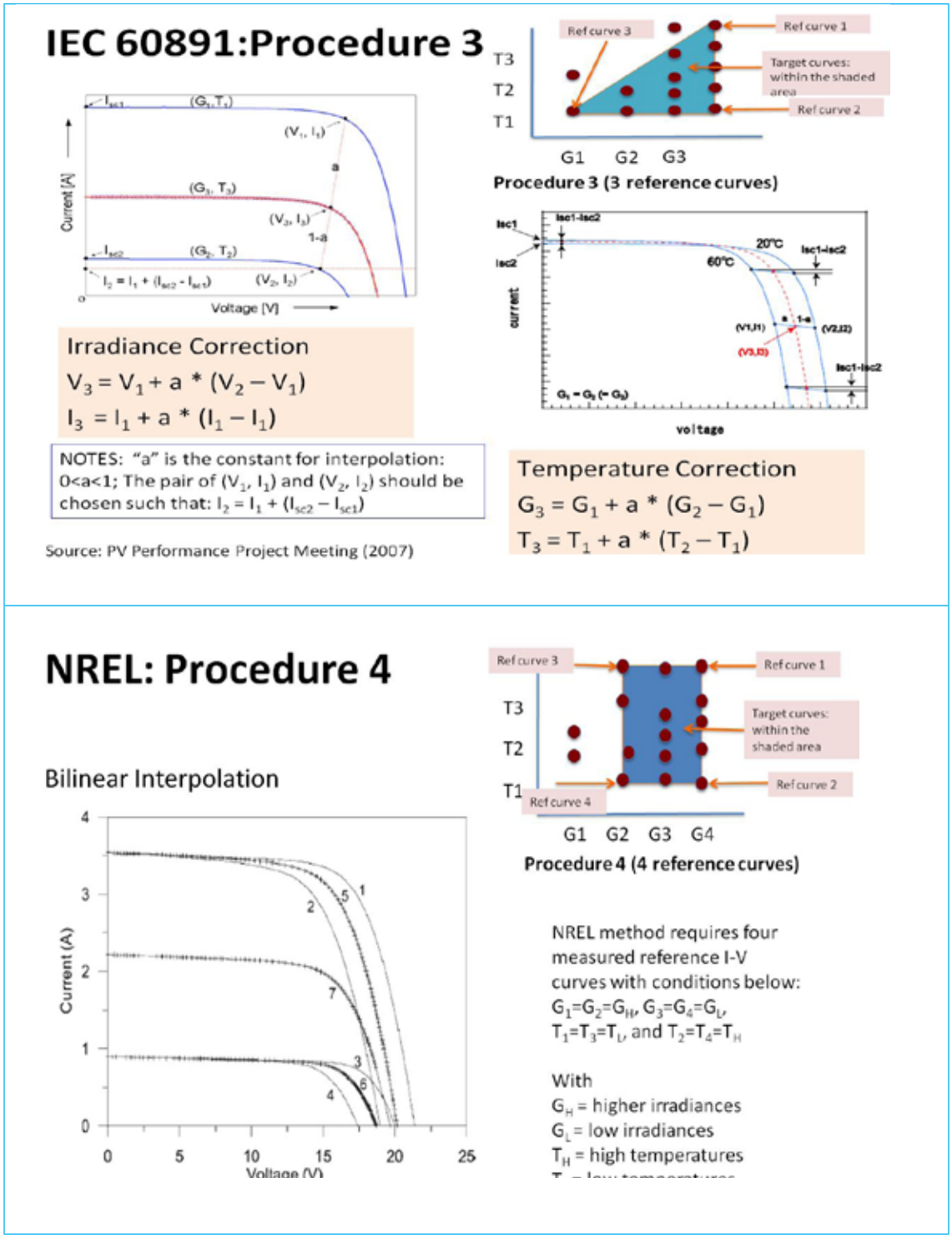


Figure A4. IEC 60891 Procedure 3 and NREL Method Procedure 4.

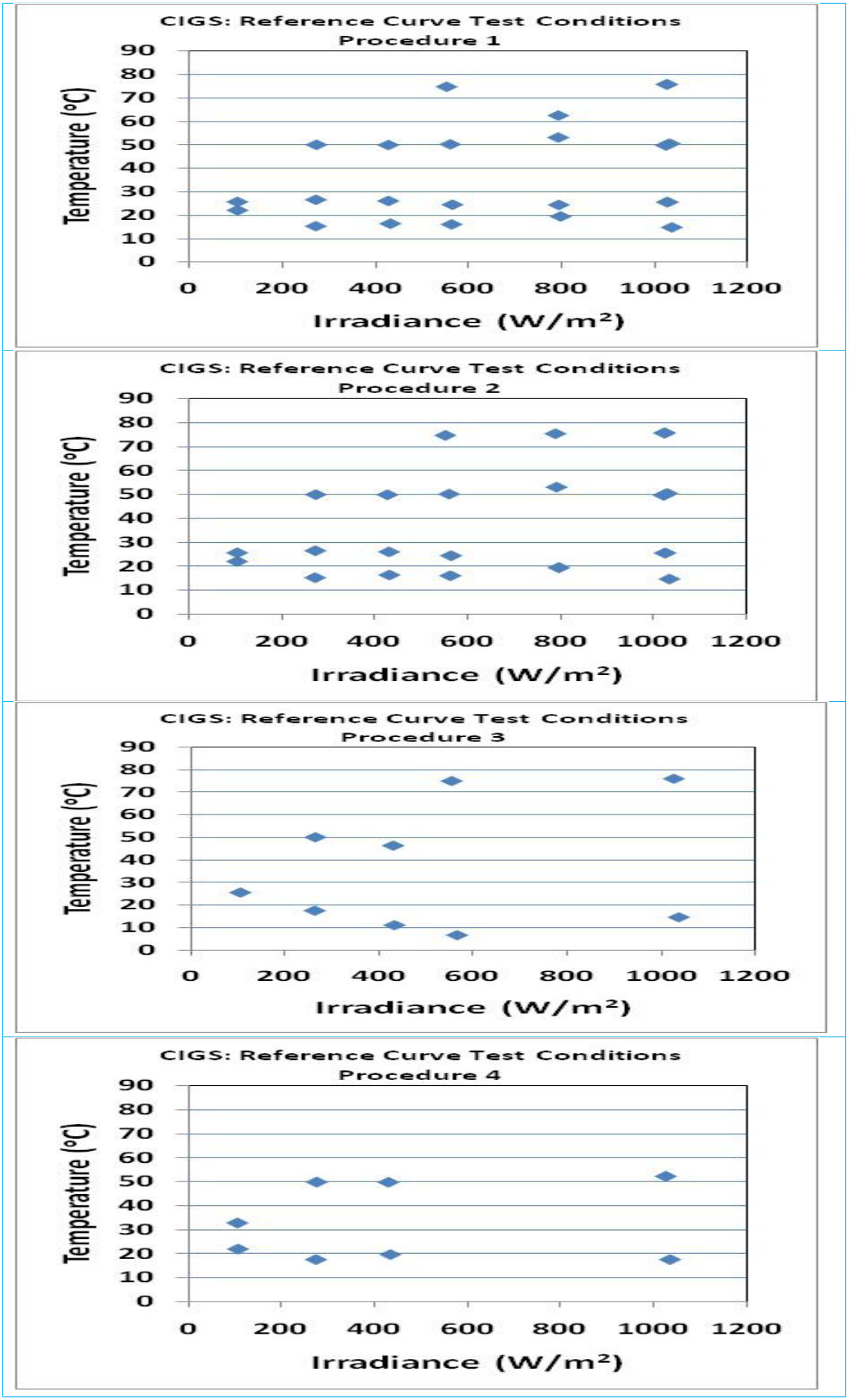


Figure A5. Test conditions to obtain reference curves—CIGS.

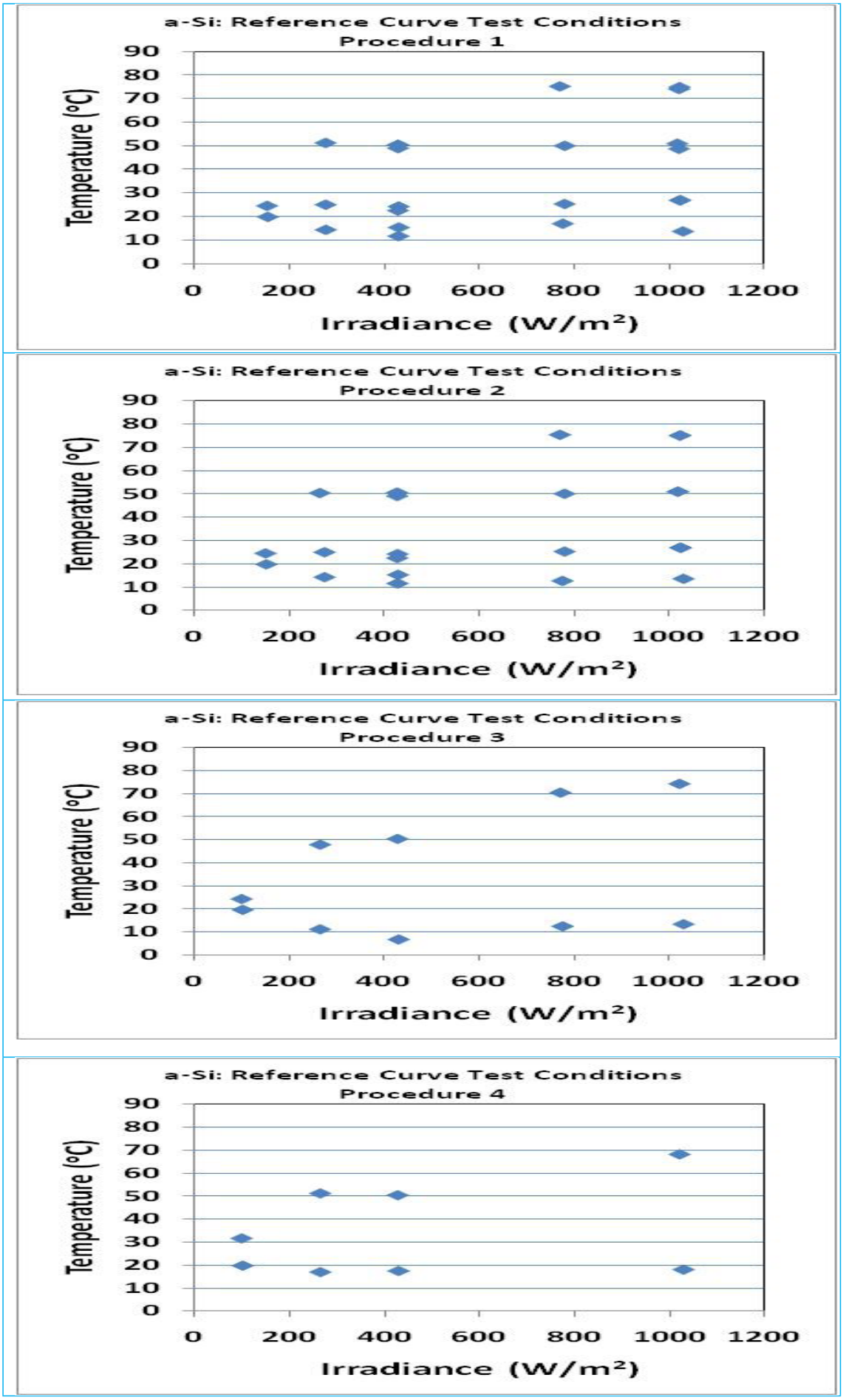


Figure A6. Test conditions to obtain reference curves—a-Si.

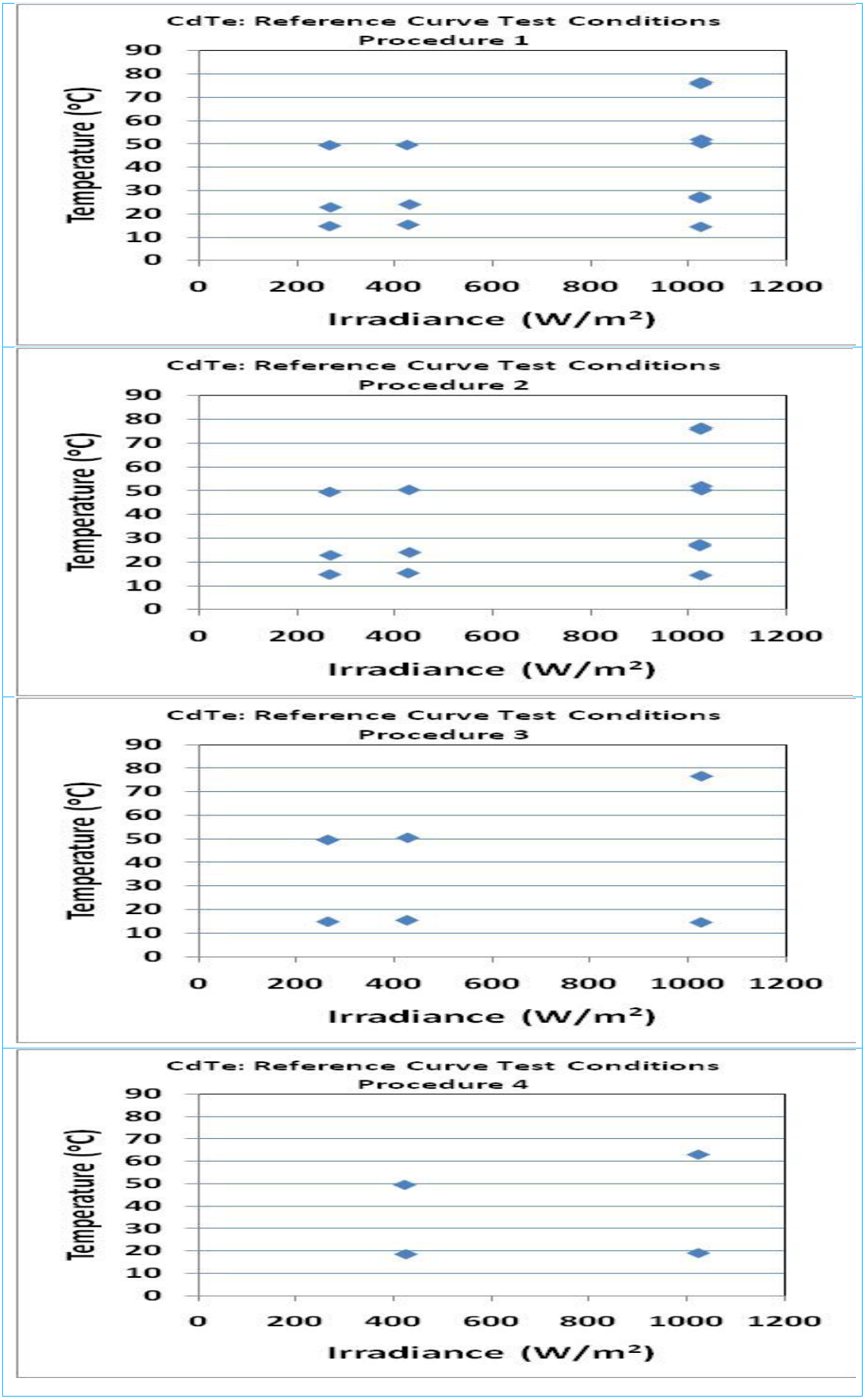


Figure A7. Test conditions to obtain reference curves—CdTe.

Table A1

Temperature Coefficients of All Four Technologies at Each Specific Irradiance Level

Technology	Irradiance (Approximate)	I_{sc} (A/°C)	V_{oc} (V/°C)	I_{max} (A/°C)	V_{max} (V/°C)	P_{max} (W/°C)
Mono-Si	1000	0.0021	-0.1667	-0.0009	-0.1744	-0.8230
	800	0.0024	-0.1671	0.0004	-0.1763	-0.6264
	600	0.0019	-0.1669	0.0000	-0.1673	-0.4627
	400	0.0005	-0.1727	-0.0002	-0.1793	-0.3378
	200	-0.0004	-0.1798	-0.0007	-0.1719	-0.1768
	100	0.0015	-0.1781	0.0012	-0.1724	-0.0382
a-Si	1000	0.0008	-0.4182	0.0008	-0.2133	-0.0745
	800	0.0005	-0.4170	0.0004	-0.2140	-0.0740
	600	0.0005	-0.4027	0.0004	-0.2203	-0.0490
	400	0.0002	-0.4015	0.0005	-0.2839	-0.0390
	200	0.0000	-0.3774	0.0000	-0.2022	-0.0212
	100	0.0000	-0.3671	0.0002	-0.3506	-0.0087
CIGS	1000	0.0004	-0.0912	0.0035	0.0193	0.0876
	800	-0.0003	-0.0923	0.0025	0.0334	0.0898
	600	-0.0001	-0.0978	0.0007	0.0190	0.0352
	400	-0.0003	-0.0993	0.0002	0.0057	0.0082
	200	-0.0010	-0.1075	-0.0007	-0.0077	-0.0140
	100	-0.0001	-0.1093	-0.0002	-0.0190	-0.0073
CdTe	1000	0.0008	-0.1222	-0.0001	-0.0590	-0.0914
	800	0.0001	-0.1341	0.0000	-0.0576	-0.0190
	600	0.0001	-0.1406	0.0000	-0.0576	-0.0182
	400	-0.0003	-0.1578	-0.0003	-0.0634	-0.0341
	200	0.0006	-0.1982	0.0006	-0.1126	-0.0078
	100	0.0000	-0.2049	0.0000	-0.1198	-0.0189

TABLE A2

Linearity Checking of Test Modules As Per IEC 60904-10

(the red highlighted data do not meet the linearity deviation limit)

CIGS	Linearity deviation for temperature (°C)			
	15	25	50	75
Linearity deviation of I_{sc} for temperature at 15-75°C temperature range and a single irradiance of 1000 W/m² (allowed limit: <5%)	0.2%	-0.4%	0.6%	-0.2%
Linearity deviation of V_{oc} for temperature at 15-75°C temperature range and a single irradiance of 1000 W/m² (allowed limit: <5%)	0.8%	-0.8%	-0.4%	0.4%
Linearity deviation of P_{max} for temperature at 15-75°C temperature range and a single irradiance of 1000 W/m² (allowed limit: <5%)	0.0%	1.0%	-1.9%	1.0%

CIGS	Linearity deviation for irradiance (W/m2)						
	1100	1000	800	600	400	200	100
Linearity deviation of I_{sc} for irradiance at 100-1100 W/m² irradiance range and a single temperature of 25°C (allowed limit: <2%)	-2.0%	-3.0%*	-0.9%	0.4%	-3.0%*	-1.9%	-7.9%
Linearity deviation of V_{oc} for irradiance at 100-1100 W/m² irradiance range and a single temperature of 25°C (allowed limit: <5%)	8.1%**	-3.6%	-3.4%	-1.4%	-3.1%	3.5%	-0.2%
	* Seems to be a slight experimental/processing error as the device meets the linearity requirement at above 600 W/m² and at 400 W/m²; ** Could be due to the series resistance issue of this device						

TABLE A3

Linearity Checking of Test Modules As Per IEC 60904-10

(the red highlighted data do not meet the linearity deviation limit)

a-Si	Linearity deviation for temperature (°C)			
	15	25	50	75
Linearity deviation of I_{sc} for temperature at 15-75°C temperature range and a single irradiance of 1000 W/m² (allowed limit: <5%)	0.7%	0.0%	1.9%	0.2%
Linearity deviation of V_{oc} for temperature at 15-75°C temperature range and a single irradiance of 1000 W/m² (allowed limit <5%)	0.4%	-0.3%	-0.5%	0.4%
Linearity deviation of P_{max} for temperature at 15-75°C temperature range and a single irradiance of 1000 W/m² (allowed limit: <5%)	1.1%	2.5%	-8.3% *	4.8%

a-Si	Linearity Deviation for Irradiance (W/m2)						
	1100	1000	800	600	400	200	100
Linearity deviation of I_{sc} for irradiance at 100-1100 W/m² irradiance range and a single temperature of 25°C (allowed limit: <2%)	-2.2% **	-2.3% **	-0.5%	1.0%	-0.8%	-2.9%	-13.3%
Linearity deviation of V_{oc} for irradiance at 100-1100 W/m² irradiance range and a single temperature of 25°C (allowed limit: <5%)	3.9%	-4.5%	-2.0%	6.9% *	-3.9%	-3.5%	3.1%
	* Seems to be an experimental error as the device meets the requirement at below 50°C and at 75°C or at below/above 600 W/m²; ** Neglected from deviation due to measurement uncertainty						

TABLE A4

Linearity Checking of Test Modules As Per IEC 60904-10

(the red highlighted data do not meet the linearity deviation limit)

CdTe	Linearity Deviation for Temperature (°C)			
	15	25	50	75
Linearity deviation of I_{sc} for temperature at 15-75°C temperature range and a single irradiance of 1000 W/m² (allowed limit: < 5 %)	-0.3 %	0.0 %	1.0 %	-0.4 %
Linearity deviation of V_{oc} for temperature at 15-75°C temperature range and a single irradiance of 1000 W/m² (allowed limit: < 5 %)	0.6 %	-1.0 %	0.7 %	-0.2 %
Linearity deviation of P_{max} for temperature at 15-75°C temperature range and a single irradiance of 1000 W/m² (allowed limit: < 5 %)	-3.3 %	4.5 %	-1.1 %	-0.2 %

CdTe	Linearity Deviation for Irradiance (W/m²)						
	1100	1000	800	600	400	200	100
Linearity deviation of I_{sc} for irradiance at 100-1100 W/m² irradiance range and a single temperature of 25°C (allowed limit: < 2 %)	-2.2 % *	-2.6 % *	NA	NA	-1.4 %	-3.9 %	NA
Linearity deviation of V_{oc} for irradiance at 100-1100 W/m² irradiance range and a single temperature of 25°C (allowed limit: < 5 %)	1.7 %	-1.6 %	NA	NA	-0.3 %	0.3 %	NA
	** Neglected from deviation due to measurement uncertainty; NA = module broke during measurements*						

ACRONYMS

ASTM	American Society for Testing and Materials (formerly the American Society for Testing and Materials)
AM	air mass
a-Si	amorphous silicon
CdTe	cadmium telluride
c-Si	crystalline silicon
CIGS	copper indium gallium diselenide
G	global
I_{sc}	short-circuit current
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
I-V	current-voltage
NREL	National Renewable Energy Laboratory Method
P_{max}	maximum power
PV	photovoltaic
RMSE	root mean square error
V_{max}	voltage at maximum power
V_{oc}	open circuit voltage

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ABCS-18-SR

Validation of Draft International Electrotechnical Commission 61853-2 Standard: Angle of Incidence Effect on Photovoltaic Modules

Prepared by:

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February 2013

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EXECUTIVE SUMMARY

The purpose of this study is to test and validate the draft International Electrotechnical Commission (IEC) 61853-2 standard's (IEC, 2012) experimental procedures and related mathematical models for the measurement of angle of incidence (AOI) effects on photovoltaics (PV) modules. This is a continuation of a previous project to test and validate the IEC 61853-1 standard. A comprehensive report related to the validation of the IEC 61853-1 standard can be downloaded from the Solar America Board for Codes and Standards *(Solar ABCs)* website (*Photovoltaic Module Power Rating per IEC 61853-1 Standard: A Study Under Natural Sunlight*, March 2011). Both of these experimental projects were carried out at Arizona State University Photovoltaic Reliability Laboratory according to the outdoor test procedure of the standard.

This validation study is important because PV modules are typically tested and rated only at three different test conditions—standard test conditions (STC) (1,000 watts per square meter [W/m^2] irradiance, 25°C cell temperature), low irradiance (200 W/m^2 irradiance, 25°C cell temperature), and nominal operating cell temperature (800 W/m^2 irradiance, 20°C ambient temperature). In addition, all these measurements are currently conducted at only a single spectral level of air mass 1.5 and at a single incidence angle of zero degree.

Installed modules, however, operate at a wide range of temperatures, irradiance levels, angles of incidence, and solar spectra. To accurately predict the energy production of the modules under various field conditions, it is necessary to characterize the modules at a wide range of temperatures, irradiances, angles of incidence, and spectra.

Toward that end, the IEC is developing the IEC 61853 standard titled "Photovoltaic Modules Performance Testing and Energy Rating." This standard has four parts, and this Solar ABCs report focuses on the section of the second part (IEC 61853-2) concerned with AOI effects on PV modules. A working group of IEC Technical Group 82 developed the procedures and mathematical models used in the first two parts of the standard, and the accuracy of these procedures and models must be independently tested and validated. The IEC 61853-2 standard is in the IEC review and approval process and is expected to be released in 2015.

This report presents the effects of AOI on short circuit current (I_{sc}) for five different module technologies:

- monocrystalline silicon (mono-Si),
- polycrystalline silicon (poly-Si),
- amorphous silicon (a-Si),
- cadmium telluride (CdTe), and
- copper indium gallium selenide (CIGS).

The superstrate/encapsulant/substrate materials of each of these modules are:

- glass/ethylene vinyl acetate (EVA)/polymer—mono-Si,
- glass/EVA/polymer—poly-Si,
- glass/EVA/glass—a-Si,
- glass/EVA/glass—CdTe, and
- glass/EVA/polymer—CIGS.

In addition, we used:

- four irradiance sensors—Kipp & Zonen pyranometer, Eppley PSP pyranometer, Kipp & Zonen pyrheliometer, and polycrystalline silicon reference cell—to measure global and direct irradiance levels,
- thermal sensors to measure the ambient temperature as well as the test module and reference cell temperatures,
- a data acquisition system to collect and store the output of thermal sensors and the I_{sc} of the test modules and reference cell, and
- an attitude reference heading device to directly measure AOI.

We conducted three rounds of measurements and improved the experimental setup and data processing strategies after each round based on lessons learned:

- During the first round (see Appendix C for details), we encountered
  - — multi-curve tracer that could record and store data in one-minute intervals, which we determined was not fast enough for our purposes;
  - — irradiance sensors that had not been calibrated, so that we could not confirm the accuracy of the measurements or calculate uncertainty; and
  - — a human error in constructing Equation A6.
- During the second round (see Appendix D for details), we
  - — used transducers and a data logger and multiplexer rather than a multi-curve tracer, which increased the data storage and measurement speed from one minute to 30 seconds;
  - — identified and corrected the human error in Equation A6; and
  - — found that the reference devices had still not been calibrated and we could not calculate the uncertainty analysis.
- During the third and final round of measurements (detailed in the body of this report), we incorporated the lessons learned from the first two rounds and used calibrated reference devices.

During the rotation of the tracker platform, the test equipment measured and stored I_{sc} and temperature of all the test modules, irradiance data from all the irradiance sensors, and AOI data from the attitude reference heading device. We processed the data according to the IEC 61853-2 model to determine the relative light transmission or relative optical response of all the test modules, free from the influence of the diffuse light component and the cosine effect. We also compared this data with the data derived for the air-glass interface using various theoretical light transmission models and with the data derived specifically for PV modules with glass superstrate using an empirical model developed by Sandia National Laboratories.

The major conclusions resulting from this project are:

- Accurate test results require meticulous experimental setup and rigorous test procedures.
- Test results show nearly identical relative light transmission plots for all five test modules with glass superstrate regardless of the type of PV cell technology (mono-Si, poly-Si, a-Si, CdTe, or CIGS). This indicates that the reflective losses are governed almost exclusively by the air-glass interface of the PV modules.

- The relative light transmission plots obtained using the IEC 61853-2 model were in good agreement with the plots obtained using the theoretical air-glass interface models and the empirical model developed by Sandia National Laboratories for the glass superstrate PV modules.
- The standard states that "for the flat glass superstrate modules, the AOI test does not need to be performed, rather, the data of a flat glass air interface can be used." The results obtained in the current study validate this statement.

Author Biographies

Brett Knisely and Suryanarayana Vasantha Janakeeraman are M.S. students at Arizona State University (ASU). Both are research assistants at the ASU Photovoltaic Reliability Laboratory (ASU-PRL) evaluating the performance of photovoltaic (PV) modules under various outdoor conditions.

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The Solar America Board for Codes and Standards (Solar ABCs) provides an effective venue for all solar stakeholders. A collaboration of experts formally gathers and prioritizes input from groups such as policy makers, manufacturers, installers, and large- and small-scale consumers to make balanced recommendations to codes and standards organizations for existing and new solar technologies. The U.S. Department of Energy funds Solar ABCs as part of its commitment to facilitate widespread adoption of safe, reliable, and cost-effective solar technologies.

Acknowledgments

The authors gratefully acknowledge the support and comments received from David King (DK Solar Works; formerly Sandia National Laboratories), Bill Marion (National Renewable Energy Laboratory [NREL]), John Wohlgemuth (NREL), George Kelly (BP Solar), and Sarah Kurtz (NREL).

Table of Contents

Disclaimer 2

Executive Summary 3

Author Biographies 6

Solar ABCs 6

Acknowledgments 6

Introduction 8

Background 9

Scope and Purpose of IEC 61853-2 Standard 11

Outdoor Measurement Procedure of IEC 61853-2 Standard 12

Outdoor Measurement Procedure of ASU-PRL 14

Results and Discussion 19

Uncertainty Analysis 23

Conclusions 24

Acronyms 25

References 26

Scope of Appendices 27

Appendix A: Sandia Procedure to Determine Relative Optical Response 28

Appendix B: Crosschecking of Aoi Device Using a Manual Method 31

Appendix C: Lessons Learned 1: Round 1 Measurements Using a Multi-Curve Tracer . 33

Appendix D: Lessons Learned 2: Round 2 Measurements Using a Data Logger 35

Appendix E: Inter-Comparison and Crosschecking of Pyranometers 37

Appendix F: Measurement of f_2(AOI) Versus AOI in the Opposite Direction 40

Introduction

The reflected and transmitted fractions of incident light determine the amount of sunlight that reaches photovoltaic (PV) solar cells. Module design influences the reflections of this light within the superstrate and encapsulant and at the air/superstrate, superstrate/encapsulant, and encapsulant/cell interfaces. It also influences transmittances through the superstrate and encapsulant. These reflections and transmittances are functions of the solar incidence angle. The surface roughness and antireflective coatings of superstrates heavily influence the incident angle effect.

The purpose of this study is to test and validate the draft International Electrotechnical Commission (IEC) 61853-2 standard's (IEC, 2012) experimental procedures and related mathematical models for the measurement of angle of incidence (AOI) effects on PV modules. This is a continuation of a previous project to test and validate the IEC 61853-1 standard. A comprehensive report related to the validation of the IEC 61853-1 standard can be downloaded from the Solar America Board for Codes and Standards (*Solar ABCs*) website (*Photovoltaic Module Power Rating per IEC 61853-1 Standard: A Study Under Natural Sunlight,* March 2011).

This validation study is important because PV modules are typically tested and rated only at three different test conditions—standard test conditions (STC) (1,000 watts per square meter [W/m^2] irradiance, 25°C cell temperature), low irradiance (200 W/m^2 irradiance, 25°C cell temperature), and nominal operating cell temperature (800 W/m^2 irradiance, 20°C ambient temperature). In addition, all these measurements are currently conducted at only a single spectral level of air mass (AM) 1.5 and at a single incidence angle of zero degree.

In actual installations, however, modules operate at a wide range of temperatures, irradiance levels, angles of incidence, and solar spectra. To accurately predict the energy production of the modules under various field conditions, it is necessary to characterize the modules at a wide range of temperatures, irradiances, angles of incidence, and spectra.

Toward that end, the IEC is developing the IEC 61853 standard titled "Photovoltaic Modules Performance Testing and Energy Rating" to characterize PV modules at a wide range of test conditions. This standard has four parts. The first (IEC 61853-1) was released in January 2011 and deals with the characterization of PV modules at 23 test conditions of irradiance and temperature but at a single angle of incidence (zero degree) and a single spectrum (AM1.5). The second (IEC 61853-2) is in the IEC review and approval process and is expected to be released in 2015. It addresses the wide range of angles of incidence and spectral effects. The third and fourth parts of the standard deal with energy rating calculations and reference conditions respectively, and are still under development. A working group of IEC Technical Group 82 developed the procedures and mathematical models used in the first two parts of the standard, and the accuracy of these procedures and models must be independently tested and validated.

Background

There are two primary ways AOI influences the short circuit current (I_{sc}), and thus the power output, of PV modules. The first is a purely mechanical/geometrical effect due to the module's orientation with respect to the incident sunlight. It is often referred to as the "cosine effect." It states that the irradiance incident on the module decreases with increasing AOI and it is proportional to cos(AOI). The second way AOI influences I_{sc} is related to the optical effects or surface characteristics of the module itself. PV manufacturers go to great lengths to improve the optical characteristics of modules by incorporating antireflective coatings, rolled or textured glass, or other methods.

This report presents the effects of AOI on I_{sc} for five different module technologies:

- monocrystalline silicon (mono-Si),
- polycrystalline silicon (poly-Si),
- amorphous silicon (a-Si),
- cadmium telluride (CdTe), and
- copper indium gallium selenide (CIGS).

The superstrate/encapsulant/substrate materials of each of these modules are:

- glass/ethylene vinyl acetate (EVA)/polymer—mono-Si,
- glass/EVA/polymer—poly-Si,
- glass/EVA/glass—a-Si,
- glass/EVA/glass—CdTe, and
- glass/EVA/polymer—CIGS.

We conducted three rounds of measurements on these modules and improved the experimental setup and data processing strategies based on lessons learned in each of the the first two rounds:

- During the first round (see Appendix C for details), we encountered
  - a multi-curve tracer that could record and store data in one-minute intervals, which we determined was not fast enough for our purposes;
  - irradiance sensors that had not been calibrated, so that we could not confirm the accuracy of the measurements or calculate uncertainty; and
  - a human error in constructing Equation A6.
- During the second round (see Appendix D for details), we
  - used transducers and a data logger and multiplexer rather than a multi-curve tracer, which increased the data storage and measurement speed from one minute to 30 seconds;
  - identified and corrected the human error in Equation A6; and
  - found that the reference devices had still not been calibrated, and we could not calculate the uncertainty analysis.
- During the third and final round of measurements (detailed in the body of this report), we incorporated the lessons learned from the first two rounds and used calibrated reference devices.

We made all measurements on clear sunny days using a two-axis tracker. We used a novel device to accurately measure the AOI and three conventional reference devices to measure the irradiance—a pyranometer and a polycrystalline silicon reference cell to measure global irradiance and a pyrheliometer to measure direct normal irradiance.

To help the reader understand the intent and requirements of the standard, we present a synopsis of the scope, purpose, and measurement procedures of the IEC 61853-2 standard in this report. We also explain the sensitivity of test results to the experimental setup and the rigorous test procedures required to execute this project. In addition, we describe the lessons learned before the final measurements were made. We thoroughly analyzed and compared our experimental results with various empirical and theoretical models developed by various organizations including IEC and Sandia National Laboratories.

Scope and Purpose of IEC 61853-2 Standard

The scope of the IEC 61853 series of standards includes:

- test methods to map module performance over a wide range of temperature and irradiance conditions (part 1),
- test methods to determine incidence angle effects, module operating temperature, and spectral response (part 2),
- procedures for evaluating instantaneous and integrated power and energy results and an approach for providing a numerical rating for the results obtained in part 3 (part 3), and
- a definition of reference day irradiance and climatic profiles (part 4).

The purpose of part 2 of the IEC 61853 standard (IEC 61853-2) is to define procedures for measuring AOI effects, operating temperature, and spectral response on module performance. This Solar ABCs report deals only with the procedures and measurements related to AOI effects.

Outdoor Measurement Procedure of IEC 61853-2 Standard

The measurement procedure of the IEC 61853-2 standard for AOI effects is based on collecting the I_{sc} data of the test modules over a wide range of light incident angle. The required test apparatus, experimental setup, and measurement procedures are briefly presented below. For detailed and exact procedures, refer to the standard (IEC, 2012).

Test Apparatus

The standard identifies the use and technical requirements of test apparatus, including:

- irradiance sensors to measure the global and direct irradiance levels (reference cell for global irradiance and direct irradiance level using shadowing/collimating method as described in the "measurement procedure" below or a combination of pyranometer for global irradiance and pyrheliometer for direct normal irradiance),
- thermal sensors to measure the ambient temperature as well as the test module and reference cell temperatures,
- a data acquisition system (DAS) to collect and store the output of thermal sensors and the I_{sc} of the test modules and reference cell,
- a two-axis tracker to mount the test modules and change the incident angles on the test modules, and
- an AOI measuring device to determine the tilt angle to the sun and verify the coplanarity of test modules and irradiance sensors.

Test Setup

- Clean the front surfaces of the test modules.
- Mount the modules on the two-axis tracker racking system.
- Connect all the sensors and test modules to the DAS.

Measurement Procedure

- If the diffuse component does not exceed 10% of the total irradiance, then directly measured I_{sc} at various angles of incidence, $I_{sc}(\theta)$, can be used to calculate the relative angular light transmission data, $\tau(\theta)$, as delineated below. If the diffuse component exceeds 10% of the total irradiance, then the measured $I_{sc}(\theta)$ should be corrected before use in the calculation of $\tau(\theta)$. The $I_{sc}(\theta)$ correction depends on the type of irradiance sensor used (PV reference cell or pyranometer).

- If a PV reference cell device is used as an irradiance sensor, the diffuse light component should not exceed 10% of the total irradiance during the $I_{sc}(\theta)$ measurement period. If the diffuse component exceeds 10%, it can be subtracted after measuring the angular response with blocked direct light component or the diffuse component can be blocked to below 10% by reducing the field of view of the diffuse component; for example, by collimating the incident light reaching the test module.

- If the pyranometer and pyrheliometer are used as irradiance sensors, the diffuse component visible to the module is:

$$G_{diff} = G_{tpoa} - G_{dni} \cos(\theta) \quad (1)$$

Where:

G_{diff} is global diffuse irradiance

G_{tpoa} is the total irradiance in the plane of the module, as measured by a pyranometer in the module plane

G_{dni} is direct normal irradiance as measured by the pyrheliometer

θ corresponds to the tilt angle between the module normal and the direct solar irradiance.

The I_{sc} induced by the direct incident light can be estimated in the presence of the diffuse light component to be:

$$I_{sc}(\theta) = I_{sc}_measured(\theta)\ (1 - G_{diff} / G_{tpo}a\ ) \qquad (2)$$

- Use the two-axis tracker to rotate the test module with respect to the normal solar irradiance. Vary the angle between module normal and sunlight between -80° and +80° in steps of maximum 10°. Do a minimum of nine different angles to span the angles from 0 to 80°.
- The relative angular light transmission (or relative angular optical response) into the module is given by:

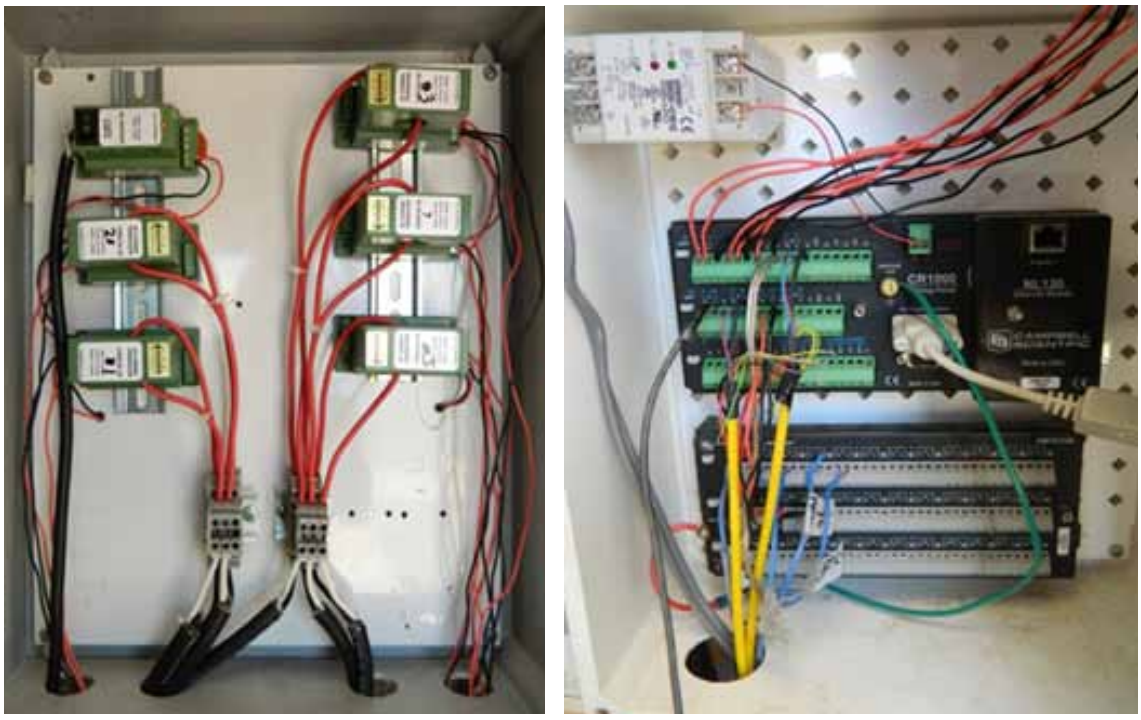
$$\tau(\theta) = I_{sc}(\theta)/(\cos(\theta)\ I_{sc}(0)) \qquad (3)$$

Outdoor Measurement Procedure of ASU-PRL

During the outdoor measurements at the Arizona State University Photovoltaic Reliability Laboratory (ASU-PRL), we closely followed the measurement procedures of the IEC 61853-2 standard. We present the test apparatus, experimental setup, and measurement procedures used in this work below.

Test Apparatus

- Test modules: We used test modules of five different technologies: mono-Si, poly-Si, a-Si, CdTe, and CIGS. In all the five modules, the superstrate was glass. The superstrate/encapsulant/substrate materials of these five modules are: glass/EVA/polymer (mono-Si); glass/EVA/polymer (poly-Si); glass/EVA/glass (a-Si); glass/EVA/glass (CdTe); and glass/EVA/polymer (CIGS).
- Irradiance sensors: We used a PV reference cell (poly-Si), two pyranometers from two vendors (Eppley PSP and Kipp & Zonen), and a pyrheliometer (Kipp & Zonen), and calibrated all the irradiance sensors. For the data analysis in this report, we processed only the data obtained using the pyranometers and pyrheliometer.
- Thermal sensors: We attached Omega T-type thermocouples to the center of the backsheet of each module using thermal tape. The manufacturer gives the accuracy for the thermocouples as +/- 1°C or 0.75% for temperatures above 0°C when temperature is expressed in °C.
- DAS: We used CR Magnetics DC current transducers to measure the I_{sc} for each module (Figure 1A). The transducers were kept in an air-conditioned shed to maintain a constant operating temperature and to comply with the manufacturer rated accuracy of 1%. A linear relation is given between current passing through the transducer and the voltage output by the transducer. We used a Campbell Scientific CR1000 data logger to record and store all the simultaneously collected data, including module I_{sc}, module temperature, and irradiance. Because temperatures of the five modules also had to be recorded, we used a multiplexer to provide the necessary number of inputs (Figure 1B). The CR1000 was also kept inside a temperature-controlled shed to meet the manufacturer rated accuracy of 1%.



(A) *(B)*

Figure 1. (A) DC current transducers; (B) CR 1000 DAS with a multiplexer.

- Two-axis tracker: We used a two-axis tracker to mount the test modules, irradiance sensors, and AOI measuring device. Ideally, the tracker should have full range of motion in both azimuth and elevation angles to achieve high angles of incidence for any time of day. The tracker used for this experiment was limited to 180° rotation about the azimuth angle and 65° of rotation about the elevation angle. High AOI could be achieved by starting the experiment at a certain time of day (around 2:30 pm for our setup) so that the tracker could use its full azimuth range. Because it was necessary to obtain E_{dni} (direct normal irradiance) measurements throughout the experiment, the pyrheliometer was allowed to track the sun using another manual or automatic 2-axis tracker.

- AOI measuring device: To determine the tilt angle to the sun for all modules and reference devices mounted on the two-axis tracker, we used a 3DM-GX3-25 miniature attitude heading reference system (Figure 2A) from MicroStrain (www.microstrain.com). It consists of a triaxial accelerometer, triaxial magnetometer, temperature sensors, and processor that run an algorithm to give static and dynamic orientation measurements with a manufacturer rated accuracy of +/- 0.5° static accuracy and a +/- 0.2° repeatability. To comply with the static accuracy of the device, the tracker stopped for six seconds at each AOI. This allowed for a stable AOI reading from the device. We used AOI software to calculate the position of the sun relative to the modules' orientation, therefore providing the AOI. We mounted the device on the surface of a plastic platform (Figure 2B) at the end of a plastic bar extending from the tracker and coplanar to the modules. AOI data was measured and recorded by a laptop that was kept outside of the shed. The tracker operator manually rotated the two-axis tracker while referring to the laptop with software that displayed the AOI of the tracker and thus of the modules and irradiance devices. The AOI data and data recorded by the Campbell Scientific CR1000 data logger were combined by synchronizing the laptop's clock to that of the data logger.

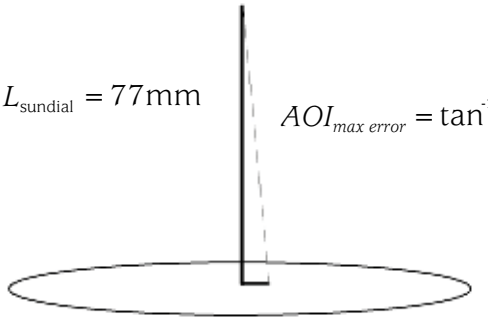
(A) *(B)*

Figure 2. (A) AOI device; (B) AOI device mounted on a plastic arm.

Ideally, to ensure that all modules and reference devices are coplanar with respect to each other, the attitude heading reference device would be placed on each module and the AOI could be read from the software and checked for consistency. However, the accuracy of the device is greatly affected by any magnetic material. Although we were careful to ensure the device was mounted on a plastic platform with non-magnetic screws so that the measurement of AOI would not be affected, when

the 3DM-GX3-25 device is placed near the modules, an accurate reading of AOI is unobtainable. To check that all modules were coplanar with respect to each other, we set the tracker to automatic mode and allowed it to track at an angle normal to the solar incidence beam. We placed both the 3DM-GX3-25 device and a sundial on the plastic mounting arm of the AOI device and "zeroed" the tracker so that the AOI device measured a maximum AOI of 0.3° or less and there was no visible shadow on the sundial (Figure 3A). We then placed the sundial at the center and corner (Figure 3B) of each module and measured the shadow of the sundial for each location. As shown in the equation below, the point on the tracker with the longest shadow length represented the least accurate point with respect to AOI ($AOI_{max\ error}$). We measured this maximum shadow length and calculated the corresponding angle to be 0.7°. Given that the initial AOI reading was a maximum of 0.3°, the projected maximum uncertainty for AOI was +/-1.0°.

$$L_{sundial} = 77mm \qquad AOI_{max\ error} = \tan^{-1}\left(\frac{L_{max\ shadow}}{L_{sundial}}\right)$$



$$L_{max\ shadow} = 1mm$$

(A) *(B)*

Figure 3. (A) Sundial "zeroed" to AOI platform with essentially no shadow present; (B) Using the sundial to check the accuracy of AOI for the mono-Si module.

Test Setup

Figure 4 shows the setup we used for this experiment. As required by the standard, we cleaned all the modules before beginning the measurements. In Figure 4, we include the name of each module technology next to the respective module, and identify all the components and test apparatus used in this work.

Figure 4. AOI measurement setup on a two-axis tracker.

Measurement Procedure

To reduce the effects of module temperature, solar irradiance, and solar spectral variations, the data should be collected as quickly as possible. For this experiment, data was simultaneously collected for five different modules and irradiance sensors. We paid careful attention to the following factors during the experiment:

1. Soiling: Dust on the surface of the modules can influence the irradiance incident on the surface of the module. Therefore, we cleaned all modules before each experiment.
2. Reflection from the surroundings: There should be no objects of abnormally high solar reflectance at the test sight. We were careful to prevent reflection from the surroundings, and we removed any unnecessary devices on the tracker that protruded from the plane of array of the modules. The ground surrounding the tracker was a flat gravel surface.
3. Standard and constant irradiance: Ideally, if the entire global irradiance of about 1,000 W/m^2 is made up of direct irradiance, then AOI measurements on PV modules become very simple. However, even on very clear days, there is always some diffuse light. Clouds will further increase the ratio of diffuse to direct irradiance. This ratio plays a prominent role in measurement accuracy, especially at higher AOI. Therefore, all the tests were performed under clear sky conditions when the ratio of direct normal irradiance (measured by the normal incidence pyrheliometer) to global normal irradiance (measured by the pyranometer) was higher than 0.85.
4. Standard and constant spectrum: Ideally, the test should be performed in a short period of time near solar noon to minimize the influence of spectral variation during the test period. Due to the physical limitation of the tracker, we performed this test around 2:30 pm in order to use the full range of the tracker. However, we

did the test quickly (in about 10 minutes) in order to maintain a constant spectrum throughout the experiment. We changed the AOI by rotating the tracker in azimuth and elevation from west to east up to angles close to 90° (the data obtained in the opposite direction, east to west, is presented in Appendix F).

5. Standard and constant temperature: Ideally, the measurements should be done at a constant module temperature. However, when AOI is changed, the module temperature cannot be kept constant due to varying irradiance level on the module surface. We measured the temperature of each module, under a very low wind speed condition, by attaching a thermocouple to the center of the backsheet and recording the temperature throughout the experiment. Using the measured temperature coefficient for current of each module, we corrected the I_{sc} values to 25°C to eliminate the influence of varying temperature during the test period.
6. Maximum number of data points: A higher number of data points will improve the confidence level in the accuracy of measurements. The minimum time interval that the data logger could collect data was 30 seconds. To obtain enough data points, with nearly constant irradiance and AM conditions, we moved the tracker 5° every 30 seconds up to AOI close to 85° (or as far as the tracker would allow). This allowed for a minimum of 18 data points to generate the I_{sc} versus AOI plots (the actual number of data points collected was 21 because we rotated the tracker more slowly at higher AOI to obtain more data points).

Relative I_{sc} With Diffuse Component and Cosine Effects

We selected the first set of data when the ratio of direct normal irradiance (G_{dni}) to total plane of irradiance (G_{tpoa}) was 87 %. During this experiment, we measured the I_{sc} data of each module and collected the I_{sc} data for each AOI. Figure 5 shows the I_{sc} data relative to the I_{sc} data obtained at zero AOI. This plot indicates that the data is amazingly identical for all the modules with glass superstrate regardless of the test technology (mono-Si, poly-Si, a-Si, CdTe, or CIGS). It is important to note that both optical and cosine effects of both the direct component and the diffuse component of the incident irradiance influence relative I_{sc} data. In order to obtain the true I_{sc} value (relative light transmission or relative optical response) free from the influence of the diffuse light component and the cosine effect, the I_{sc} data shown in Figure 5 needs to be corrected.

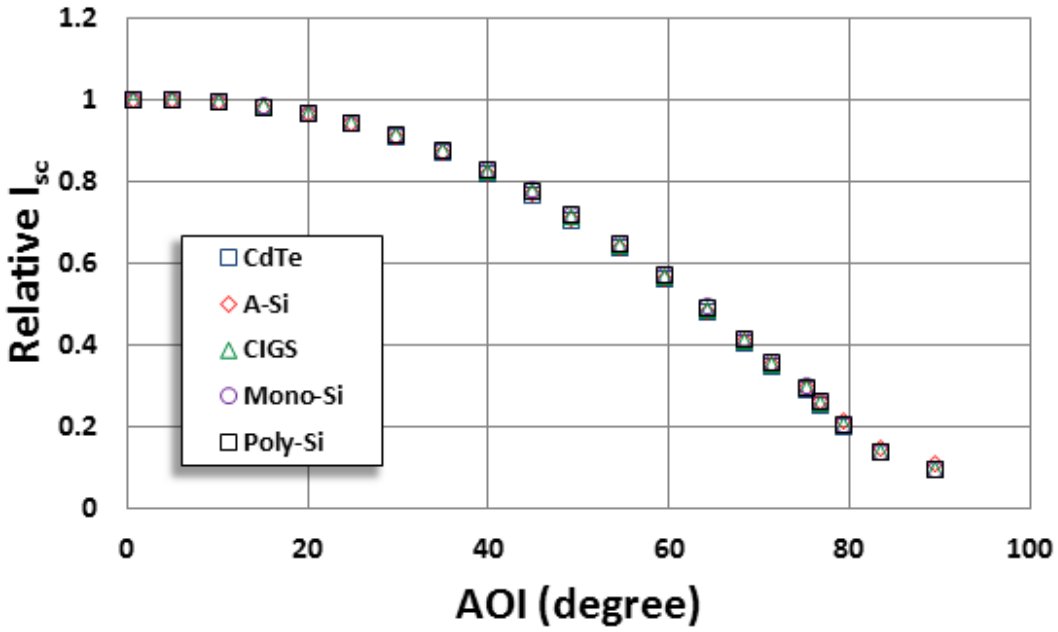


Figure 5. Relative I_{sc} with diffuse component and cosine effects.

Relative I_{sc} Without Diffuse Component and Cosine Effects

According to the requirements of the standard, the diffuse component of the incident light should not exceed 10 % of the total irradiance during the experiment. If it does, then the data should be corrected to eliminate the influence of the diffuse component. This correction can be made using the reference cell method or the pyranometer/pyrheliometer method described in the standard and delineated in the Outdoor Measurement Procedure of IEC 61853-2 Standard section of this report.

To make the correction using the reference cell method, follow the procedure delineated in the standard: "If the diffuse component exceeds 10 %, it can be subtracted after measuring the angular response with blocked direct light component or the diffuse component can be blocked to below 10 % by reducing the field of view of the diffuse component, for example by collimating the incident light reaching the test module." The I_{sc} data obtained with this correction method is now influenced only by the direct irradiance without any influence from diffuse irradiance, because the I_{sc} contribution from diffuse irradiance is subtracted from the I_{sc} value obtained with total irradiance.

This I_{sc} data, referred to as $I_{sc}(\theta)$, can then be directly used in equation 3 of this report (or equation 2 of the standard) to obtain the relative light transmission (or relative optical response) data, which is the true corrected data after eliminating the cosine and diffuse component effects.

For the correction using the pyranometer/pyheliometer method, we evaluated the IEC (IEC, 2012) and Sandia (King, Kratochvil, & Boyson, 1997) procedures/models. The IEC procedure/model is briefly described in the Outdoor Measurement Procedure of IEC 61853-2 Standard section of this report. The Sandia procedure/model involves equations 4 and 5 and the details of this procedure are provided in Appendix A (King, 2012). The relative optical response, $f_2(AOI)$, is given as:

$$f_2(AOI) = \frac{\left[E_0 \left(\frac{I_{sc}}{\left(1+\alpha_{isc}(T_c-25)\right)\cdot I_{scr}}\right) - \left(\left(E_{poa} - E_{dni}\cdot cos(AOI)\right)\right)\right]}{\left[E_{dni}\cdot \cos(AOI)\right]} \quad (4)$$

$$I_{scr} = I_{sc} * \left(\frac{E_o}{E_{poa}}\right) * \left(1 + \alpha_{Isc}(T_c - 25)\right) \quad (5)$$

Where:

E_{dni} = Direct normal solar irradiance (W/m^2)

E_{poa} = Global solar irradiance on the plane-of-array (module) ($W/m^{2)}$

E_o = Reference global solar irradiance, typically 1000 W/m^2

AOI = Angle between solar beam and module normal vector (degrees)

T_c = Measured module temperature (°C)

α_{Isc} = Short circuit current temperature coefficient (1/°C)

I_{scr} = Module short circuit current at STC (A)

I_{sc} = Measured short circuit current (A)

The plots obtained using the IEC procedure (equations 1, 2, and 3) and the Sandia procedure (equations 4 and 5) are provided in Figures 6 and 7, respectively. Both the IEC model and the Sandia model yield practically the same result. As shown in Figure 8, the modeled data can be slightly influenced at higher AOI values (>60°) by the pyranometer type (Eppley or Kipp & Zonen) probably due to the AOI sensitivity of the calibration factors of the pyranometers above 60°.

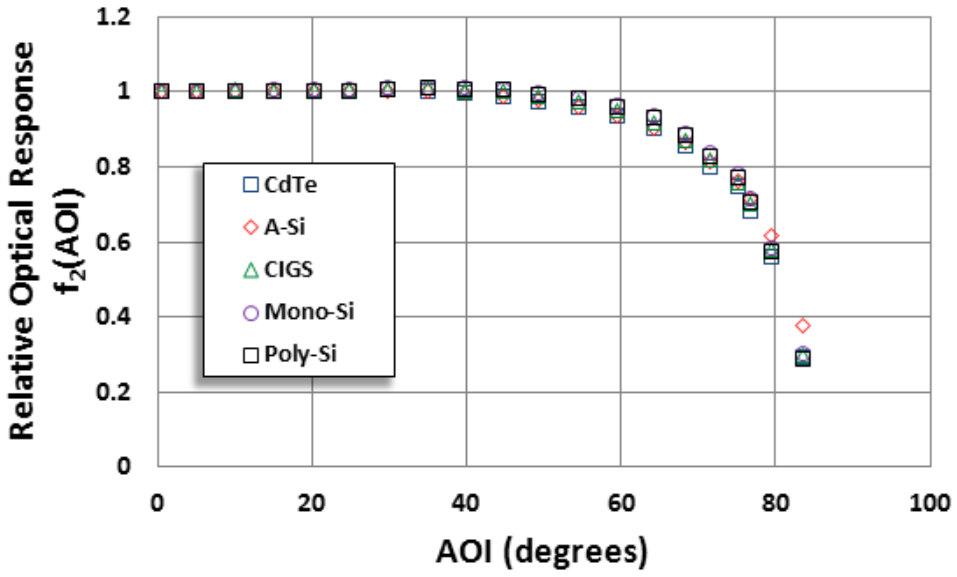


Figure 6. Relative I_{sc} without diffuse component and cosine effects—IEC method.

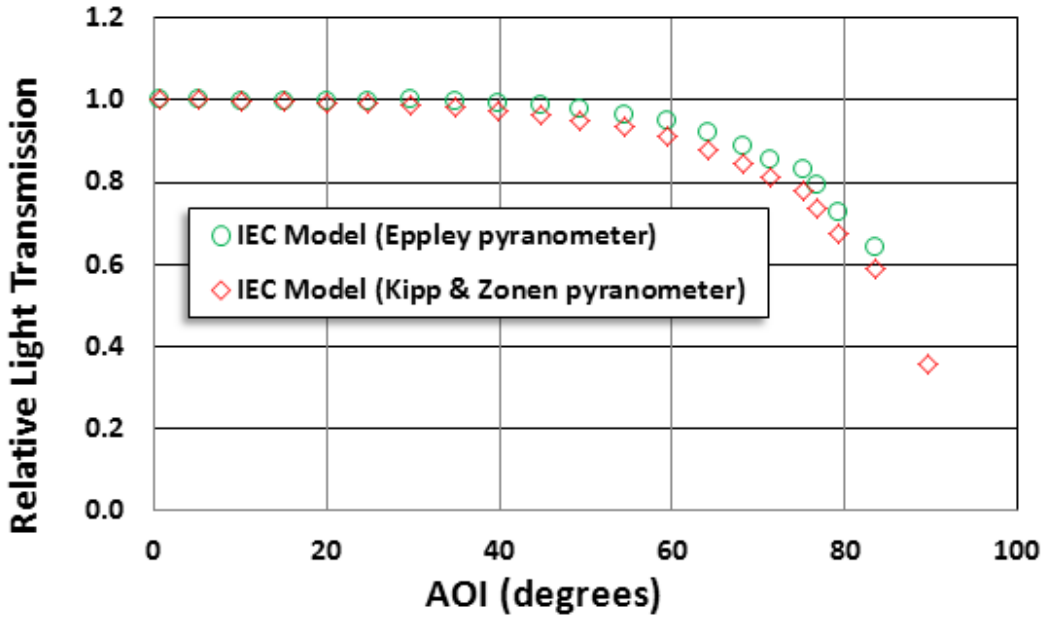


Figure 7. Relative I_{sc} without diffuse component and cosine effects—Sandia method.

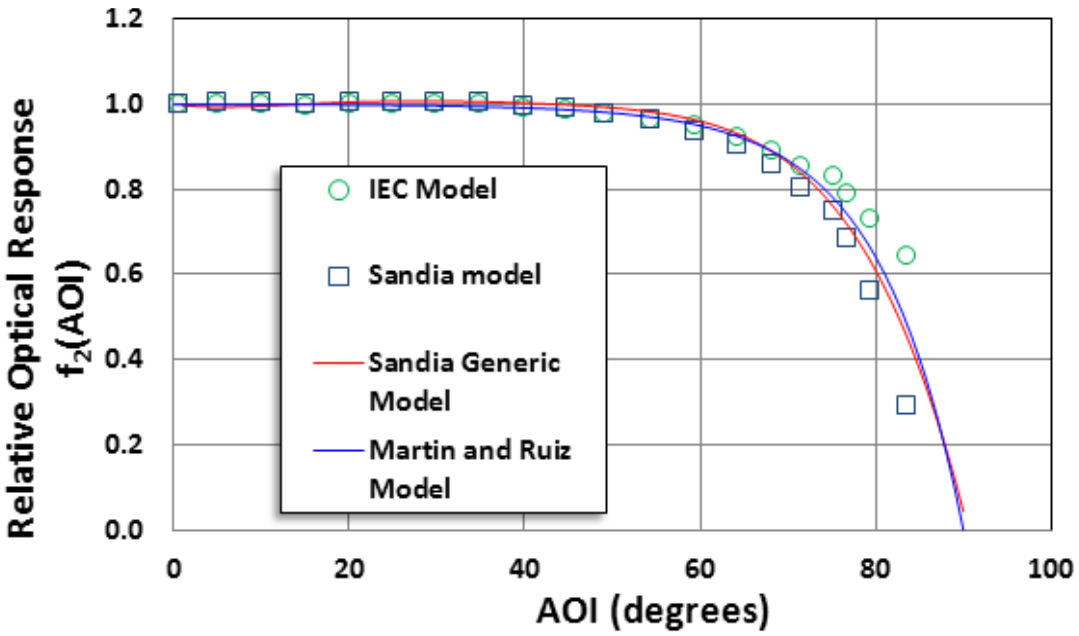


Figure 8. Comparison between Eppley and Kipp & Zonen pyranometers—CdTe Module.

Both the reference cell and pyranometer/pyrheliometer methods have advantages and disadvantages. The reference cell method reduces or eliminates the spectral mismatch error (if the test duration is long) between the reference cell and test module when matched reference cell technology is used, but it requires additional module measurements with blocked or collimated lights. The pyranometer/pyrheliometer method eliminates the additional module measurements, but there could be a spectral mismatch error between the test module, pyranometer, and pyrheliometer if the AM is much higher than 1.5. If the experiment duration is very short, this error can be nearly eliminated and can be considered a second order issue with little or no influence on the final results.

Comparison Between the Models

Based on the f2(AOI) data obtained for various PV module technologies with glass superstrate, Sandia developed a "generic" polynomial model as shown in equation 6 (see Appendix A for details).

$$f_2(AOI) = 1\text{-}2.4377E\text{-}3(AOI) + 3.1032E\text{-}4(AOI)^2\text{-}1.2458E\text{-}5(AOI)^3 + 2.1122E\text{-}7(AOI)^4\text{-}1.3593E\text{-}9(AOI)^5 \quad (6)$$

Several AOI models have been developed and reported for the glass/air interface (Martin & Ruiz, 2005) (Soto, Klein, & Beckman, 2006) (Sjerps-Koomen, Alsema, & Turkenburg, 1997). We compared the data obtained using the Sandia model and the IEC model for the CdTe module (glass superstrate) with the "generic" polynomial model of Sandia and glass/air AOI model of Martin and Ruiz (Martin & Ruiz, 2005). They all have an excellent match with each other, confirming that the relative optical response of all the glass superstrate modules is almost exclusively dictated by the glass/air interface. The draft standard states: "For modules with a flat uncoated front glass plate made of standard solar glass, the relative light transmission into the module is primarily influenced by the first glass-air interface. In this case, the test does not need to be performed, rather, the data of a flat glass air interface can be used." The experimental and modeled data presented in this report fully validate this statement.

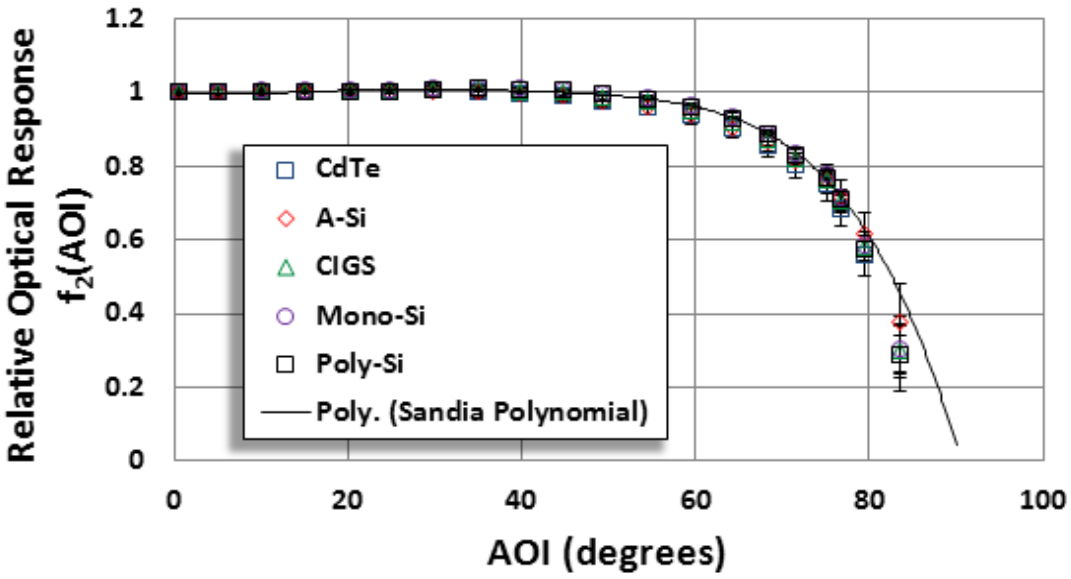


Figure 9. Comparison between various models developed by different institutions.

For a more accurate and repeatable process to test non-glass (including antireflective coated glass) or non-planar (non-flat) glass superstrate modules, follow the reference module (with flat glass superstrate and matched cell technology) approach suggested by Sandia National Laboratories (see Appendix A). Because all the models for the flat glass-air interface are leading to identical results, the reference module (flat glass with matched cell technology) and test module may be tested side-by-side to quickly identify and eliminate the experimental and data processing errors, if any.

Uncertainty Analysis

We took great care during the test setup and procedure to ensure accuracy, but minor errors are inevitable. For equations 4 and 5, each uncertainty contributor was taken into account and the magnitude of the associated uncertainty was assigned based on the calibration report or manufacturer specifications. Table 1 lists the uncertainty contributors and their uncertainties.

Table 1

Uncertainty of Various Uncertainty Contributors in Equations 4 and 5

Uncertainty Contributor (U_i)	Uncertainty
I_{sc} (U_{isc})	1.00%
Global Irradiance (U_{epoa})	1.40%
Temperature Coefficient (U_{alpha})	0.01%
Module Temperature (U_t)	0.75%
Direct Irradiance (U_{dni})	1.10%
Angle of Incidence (U_{AOI})	1.00%

The combined standard uncertainty for f_2(AOI) was quantified by taking the square root of the sum of the squares of the uncertainty estimates multiplied by the squares of their corresponding sensitivity coefficients. The sensitivity coefficients are determined by taking the derivative of the $f_{2(}$AOI) equation with respect to the uncertainty contributor.

$$u_c = \sqrt{\sum_i c_i^2 u_i^2} \tag{7}$$

The resulting uncertainties are presented as error bars in Figure 10 for each module. As calculated from the equation, the combined uncertainty for f_2(AOI) increases with increasing AOI. This can be attributed to a greater dependence on the accuracy of the pyranometer at higher AOI. For this experiment, a single sensitivity/calibration factor for the pyranometers was used for all AOI values. However, as discussed previously, the sensitivity factor is expected to vary slightly with an increase in AOI beyond 60°. Therefore, the accuracy of the pyranometer decreases with increasing AOI and the uncertainty of f_2(AOI) is expected to increase.

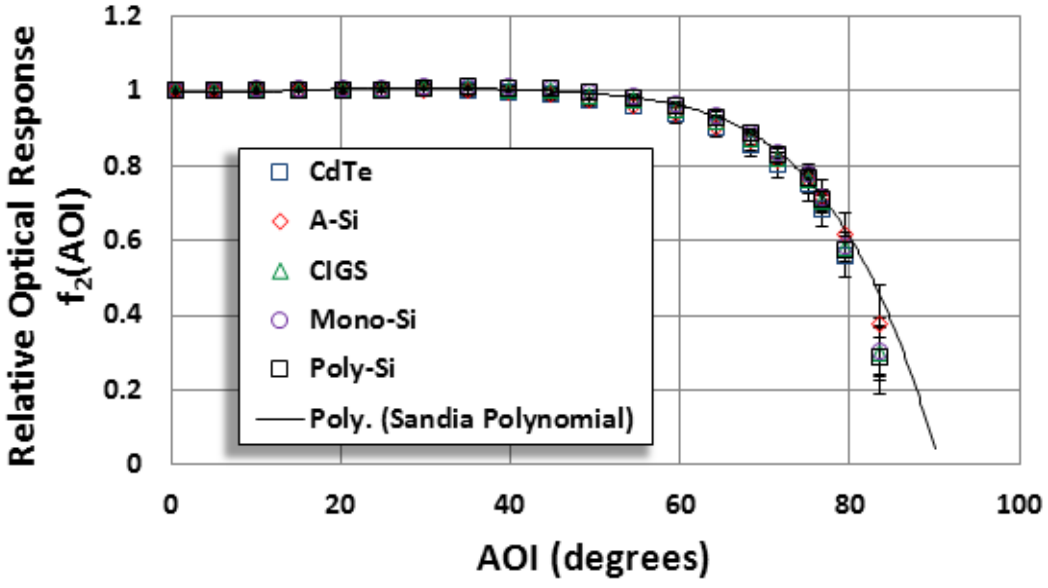


Figure 10. Relative optical response with error bars for all five module technologies.

Conclusions

During this project, we successfully tested and validated the draft IEC 61853-2 standard procedure for the measurement of incident angle effects on PV modules using an outdoor test method on five PV modules of different technologies.

Our major conclusions include:

- The results show nearly identical relative light transmission plots for all five test modules with glass superstrate regardless of the type of PV cell technology (mono-Si, poly-Si, a-Si, CdTe, or CIGS). This indicates that the reflective losses are governed almost exclusively by the air-glass interface of the PV module.
- The relative light transmission plots obtained using the IEC 61853-2 model were in good agreement with the plots obtained using the theoretical air-glass interface models and the empirical model developed by Sandia National Laboratories for glass superstrate PV modules.
- The standard states that "for the flat glass superstrate modules, the AOI test does not need to be performed, rather, the data of a flat glass air interface can be used." The results of this study validate this statement.
- Obtaining accurate results required careful experimental setup and rigorous test procedures.
- For a more accurate and repeatable process to test non-glass or non-planar (non-flat) glass superstrate modules, the reference module (with flat glass superstrate and matched cell technology) approach suggested by Sandia National Laboratories (Appendix A) may be followed. The reference module and test module may be tested side-by-side to quickly identify and eliminate the experimental and data processing issues, if any.

Acronyms

AM	air mass
AOI	angle of incidence
a-Si	amorphous silicon
ASU-PRL	Arizona State University Photovoltaic Reliability Laboratory
CdTe	cadmium telluride
CIGS	copper indium gallium selenide
cos	cosine
DAS	data acquisition system
DC	direct current
E_{dni}	direct normal solar irradiance (W/m^2)
E_{poa}	global solar irradiance in the plane-of-array (module) (W/m^2)
EVA	ethylene vinyl acetate
IEC	International Electrotechnical Commission
I_{sc}	short circuit current
I-V	current-voltage
mono-Si	monocrystalline silicon
poly-Si	polycrystalline silicon
PV	photovoltaic
Solar ABCs	Solar America Board for Codes and Standards
STC	standard test conditions

References

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Martin, N. & Ruiz, J.M. (2005). Annual angular reflection losses in PV modules. *Progress in Photovoltaics*. 13. 75–84.

Sjerps-Koomen, E.A., Alsema, E.A., & Turkenburg, W.C. (1997). A simple model for PV module reflection losses under field conditions. *Solar Energy*. 57. 421-432.

Soto, W.D., Klein, S. A., & Beckman, W.A. (2006). Improvement and validation of a model for photovoltaic array performance. *Solar Energy*. 80. 78–88.

Scope of Appendices

Appendix A: Sandia Procedure to Determine Relative Optical Response

The Sandia procedure to measure relative optical response has already been published (King, Kratochvil, & Boyson, 1997). An extended and detailed version of this procedure was recently documented in a private communication, and this document is reproduced in Appendix A.

Appendix B: Crosschecking of AOI Device Using a Manual Method

We directly measured the AOI data provided in this report using a 3DM-GX3-25 sensor from MicroStrain. In order to crosscheck that these measured data are accurate, we also manually determined the AOI data, and Appendix B discusses this process. We found that the AOI data obtained by the sensor and manual methods matched.

Appendix C: Lessons Learned 1: Round 1 Measurements Using a Multi-Curve Tracer

During the first round of measurements, we used a multi-curve tracer to obtain the entire current-voltage (I-V) curve including the short circuit current data required for the AOI experiment. We discuss the lessons learned during the first round of measurements in Appendix C. (Note that during the third and final round of measurements, we used calibrated transducers and a data logger with a multiplexer to gather the data that we used in the body of this report.)

Appendix D: Lessons Learned 2: Round 2 Measurements Using Transducers and Data Logger

During the second round of measurements, the transducers and data logger we used were not calibrated, so we could not do an uncertainty analysis. We present the lessons learned during the second round of measurements in Appendix D. (Note that during the third and final round of measurements, we used calibrated transducers and a data logger with a multiplexer to gather the data that we used in the body of this report.)

Appendix E: Inter-Comparison and Crosschecking of Pyranometers

Because the accuracy of the data obtained from the pyranometer is extremely important in these relative light transmission experiments, we decided to compare and crosscheck the data using two calibrated pyranometers from two different manufacturers. Appendix E provides inter-comparison results obtained with Eppley and Kipp & Zonen pyranometers.

Appendix F: Measurement of f2(AOI) Versus AOI in the Opposite Direction

The standard states: “For devices with rotational symmetry of the reflectivity with respect to the module normal, do a minimum of 9 different angles to span the angles from 0 to 80° for one direction and assume the reflectivity to be identical for the second orthogonal direction. For rotationally asymmetrical devices, the full measurement series needs to be carried out for two orthogonal directions across the module plane.” In order to determine whether the test modules have any asymmetric behavior for the reflectivity, we carried out these measurements for both directions and we present the results of these measurements in Appendix F.

Appendix A: Sandia Procedure To Determine Relative Optical Response, F_2(AOI)

Measuring Angle of Incidence (AOI) Influence on PV Module Performance

Private Communication with David L. King (June 2012)

There are two AOI influences that need to be considered—"mechanical" and "optical." The mechanical influence really doesn't have anything to do with the module itself, but rather its orientation relative to the incident sunlight, often called the "cosine effect." The beam solar irradiance incident on the module is reduced by cos(AOI).

The optical effect is due to the surface characteristics of the module, which can be highly planar (float glass), dimpled (rolled glass), coated with antireflective (AR) coatings, heavily textured for light gathering at large AOI, or specifically patterned for optical concentration purposes. The primary influence on the optical effect is increasing reflectance loss as AOI increases. Both of these AOI influences apply primarily to the beam or direct component of sunlight, rather than the diffuse component of sunlight.

The Sandia module performance model attempts to account for both these influences using an expanded expression for the solar irradiance, called the effective solar irradiance (E_e), which in turn determines the module's short circuit current (I_{sc}). Equation (A1) gives the Sandia expression for E_e, and Equation (A2) gives the resulting equation for I_{sc}. The intent of this document is to provide a discussion of the procedures that can be used to empirically measure the optical effect, f_2(AOI).

$$E_e = [E_{dni} * \cos(AOI) * f_2(AOI) + f_d * (E_{poa} - E_{dni} * \cos(AOI))]/E_o \quad \text{(A1)}$$

$$I_{sc} = I_{sco} * [1 + \alpha I_{sc} * (T_c - 25)] * f_1(AM_a) * E_e \quad \text{(A2)}$$

Where:
E_e = Solar irradiance actually captured and used by module (effective irradiance)
E_{dni} = Direct normal solar irradiance (W/m^2)
E_{poa} = Global solar irradiance in the plane-of-array (module) (W/m^2)
E_o = Reference global solar irradiance, typically 1000 W/m^2
f_d = Fraction of diffuse irradiance used by module, typically assumed = 1
AOI = Angle between solar beam and module normal vector (degrees)
T_c = Measured module (cell) temperature (°C)
α_{Isc} = Short circuit current temperature coefficient (1/°C)
$f_1(AM_a)$ = Empirical relationship for solar spectral influence on I_{sc} versus air mass
I_{sco} = Module short circuit current at standard test conditions (STC) (A)
I_{sc} = Measured short circuit current (A)

Direct Measurement of f_2(AOI)

The direct procedure for measuring f_2(AOI) involves measuring module I_{sc} as the module is moved in angular increments using a solar tracker through a wide range of AOI conditions, 0° to 90°. The challenge is to conduct the test in a way that either minimizes or compensates for all the factors in Equations (A1) and (A2) that influence the measured I_{sc} values. The following list identifies desirable conditions and approaches, depending on the capabilities of the test equipment available:

- Conduct test during clear sky conditions when the direct normal irradiance is the dominant component; for example, when the ratio of direct normal divided by global normal irradiance is greater than about 0.85. This reduces the influence of diffuse irradiance on the determination of f_2(AOI).

- Conducting the test near solar noon also has a couple advantages—variation in the solar spectrum during the test is minimized, and the full range for AOI can typically be achieved by changing only the elevation angle of a two-axis solar tracker.
- Measure I_{sc}, E_{dni} , E_{poa} , and T_c associated with each AOI increment. E_{dni} should be measured with a thermopile pyrheliometer, and E_{poa} should ideally be measured using a thermopile pyranometer that has been calibrated as a function of AOI.
- Module temperature will vary during the test, so measured temperature should be used to translate measured I_{sc} values to a common temperature; for example, 25°C.
- If possible, record data over the full range of AOI as rapidly as possible, so that solar spectral variation can be ignored. A less than 30-minute test period is desirable. If the test period must be longer, then a spectral correction to measured I_{sc} can be done using a previously determined $f_1(AM_a)$ relationship.

The Sandia model Equations (A1) and (A2) can be solved to provide an equation for the angle-of-incidence relationship, $f_2(AOI)$, as a function of the measured variables, Equation (A3).

$$f_2(AOI) = \{[I_{sc} * E_o/(_{Isco} * f_1(AM_a) * (1 + \alpha_{Isc}(T_c - 25)))] - f_d * (E_{poa} - E_{dni} * \cos(AOI))\}/(E_{dni} * \cos(AOI)) \quad (A3)$$

In order to simplify, recognize that by definition $f_2(AOI) = 1$ when $AOI = 0^o$. Therefore, Equation (A3) can be solved for the I_{sco} value at the start and end of the outdoor test period when $AOI = 0^o$. The value solved for is not exactly I_{sco} at STC because the air mass value may not be exactly $AM_a = 1.5$ at the time of day when the $AOI = 0^o$ conditions were achieved. This calculated value is only intended to provide a reference value for I_{sc} in order to normalize $f_2(AOI) = 1$ when $AOI = 0^o$, so to avoid confusion call the calculated value I_{scr}.

$$I_{scr} = I_{sc} * E_o/\{f1(AM_a) * (1 + \alpha_{Isc}(T_c - 25)) * (E_{dni} + f_d * (E_{poa} - E_{dni}))\} \quad (A4)$$

After determining the value for I_{scr} using the average value for several measurements when $AOI = 0^o$, the measured values for $f_2(AOI)$ can be determined using Equation (3) by substituting the I_{scr} value for I_{sco}.

Further simplification in the determination of $f_2(AOI)$ can be made for conventional flat-plate modules, depending on the test procedure and assumptions made. If data for the full range of AOI is recorded in a relatively short period of time, then the influence of varying solar spectrum is likely to be negligible. In addition, for conventional flat-plate modules the assumption is usually made that they capture both diffuse and direct irradiance; therefore $f_d = 1$. Under these simplified conditions, Equations (A3) and (A4) can be rewritten as Equations (A5) and (A6).

$$I_{scr} = I_{sc} * (E_o/E_{poa}) * (1 + \alpha_{Isc}(T_c - 25)) \quad (A5)$$

$$f_2(AOI) = [E_o * (I_{sc}/(1 + \alpha_{Isc}(T_c - 25)))/I_{scr} - (E_{poa} - E_{dni} * \cos(AOI))]/(E_{dni} * \cos(AOI)) \quad (A6)$$

For conventional flat-plate glass modules, this procedure should result in empirical $f_2(AOI)$ relationships similar to those shown in Figure A1. As previously mentioned, AR-coated glass or heavily textured glass will provide different results. For the simple case with a planar glass surface, Snell's and Bougher's optic laws along with glass optical properties (index of refraction, extinction coefficient, thickness) can also be used to calculate a theoretical relationship for $f_2(AOI)$ (Soto, Klein, & Beckman, 2006).

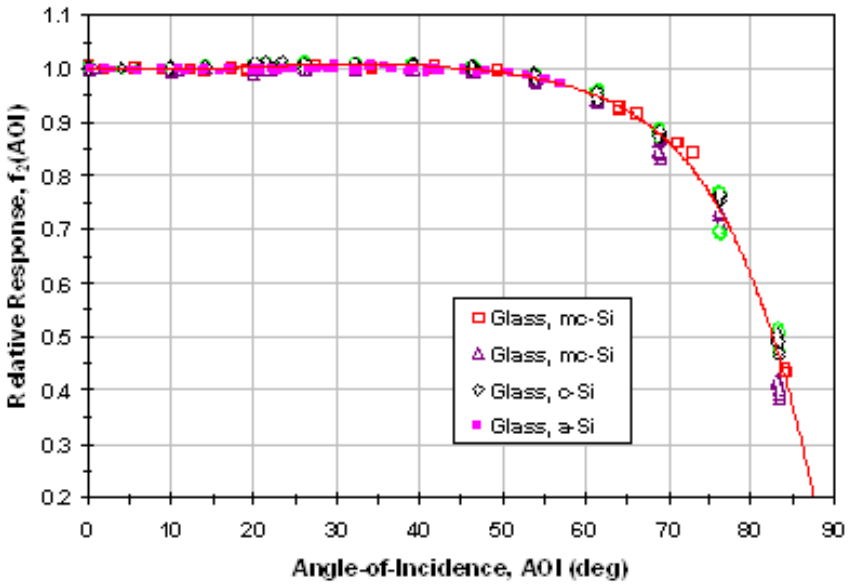

Figure A1. Empirical f_2(AOI) measurements by Sandia National Laboratories for conventional flat-plate modules with planar glass front surfaces.

Although polynomial fits to measured data can be problematic, ten years ago when the procedure was developed and the Sandia module database initiated, a fifth order fit was used to represent the measured data. There are probably better ways to represent the data, but at this point the Sandia module database has gained enough inertia that it would be difficult to change the model coefficients used to match the measured data. The "generic" polynomial used for the majority of typical glass-surface modules is given below.

$$f_2(AOI) = 1\text{-}2.4377E\text{-}3(AOI) + 3.1032E\text{-}4(AOI)^2\text{-}1.2458E\text{-}5(AOI)^3 + 2.1122E\text{-}7(AOI)^4\text{-}1.3593E\text{-}9(AOI)^5$$

Relative (Comparison) Measurements for f_2(AOI)

Although not presented in this document, an alternative test procedure providing simultaneous measurements of the I_{sc} of a test module and a reference module may possibly provide a more accurate and repeatable process. The reference module is assumed to have "known f_2(AOI)" characteristics. The reference device could be a module or an individual reference cell, ideally with matching cell technology to provide equivalent solar spectral sensitivity. For a reference device with ideally planar glass surface, the "known f_2(AOI)" could be derived from optical laws, perhaps providing a more fundamental basis for the outdoor test procedure.

REFERENCE

Soto, W.D., Klein, S. A., & Beckman, W.A. (2006). Improvement and validation of a model for photovoltaic array performance. *Solar Energy*. 80. 78–88.

Appendix B: Crosschecking of AOI Device Using a Manual Method

In this study, the AOI was directly determined using an AOI device purchased from MicroStrain. However, in the absence of this device, the AOI value can also be determined using a manual calculation (equation B1) given by Sandia National Laboratories (King, Kratochvil, & Boyson, 1997).

$$AOI = \cos^{-1}(\cos(T_m)\cos(Z_s) + \sin(T_m)\sin(Z_s)\cos(AZ_s - AZ_m)) \quad \text{(B1)}$$

Where:

AOI = solar angle of incidence (degrees)

T_m = tilt angle of module (degrees, 0° is horizontal)

Z_s = zenith angle of the sun (degrees)

AZ_m = azimuth angle of module (0° = North, 90° = East)

AZ_s = azimuth angle of sun (degrees)

As shown in Figure B1 (azimuth rotation) and Figure B2 (elevation rotation) below, the accuracy of the AOI device used in this project was crosschecked with the manual method using Equation (B1) above. These plots confirm that the AOI data obtained using the MicroStrain device was reliable and accurate.

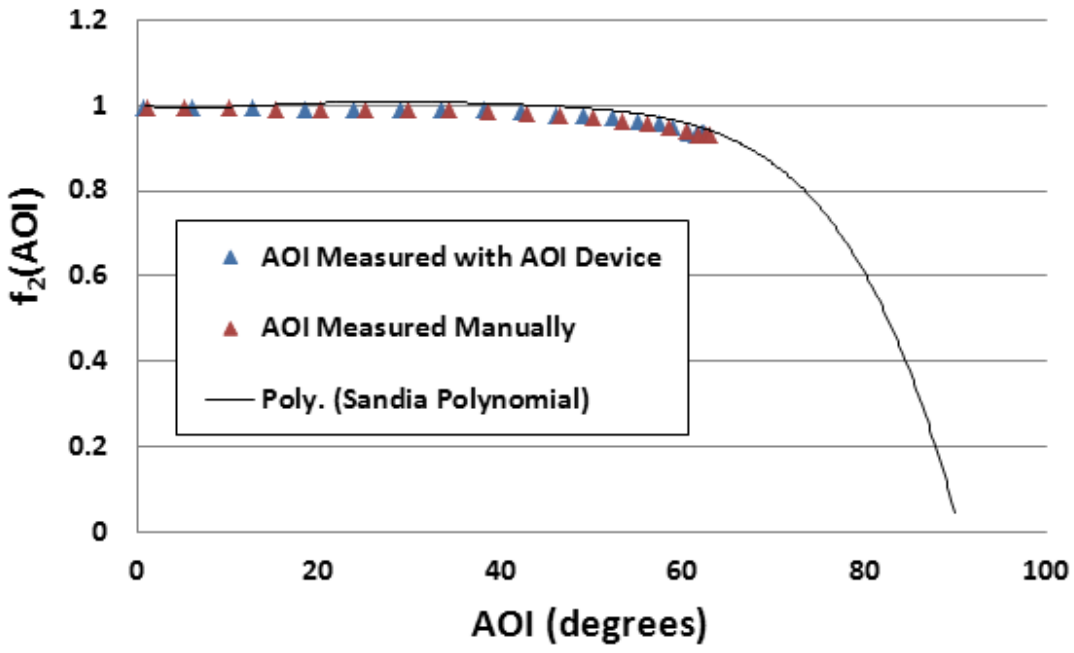

Figure B1. Comparison of relative optical responses obtained using the AOI hardware and AOI calculation for a CdTe module with glass superstrate for azimuth rotation (direct to global ratio was 0.89).

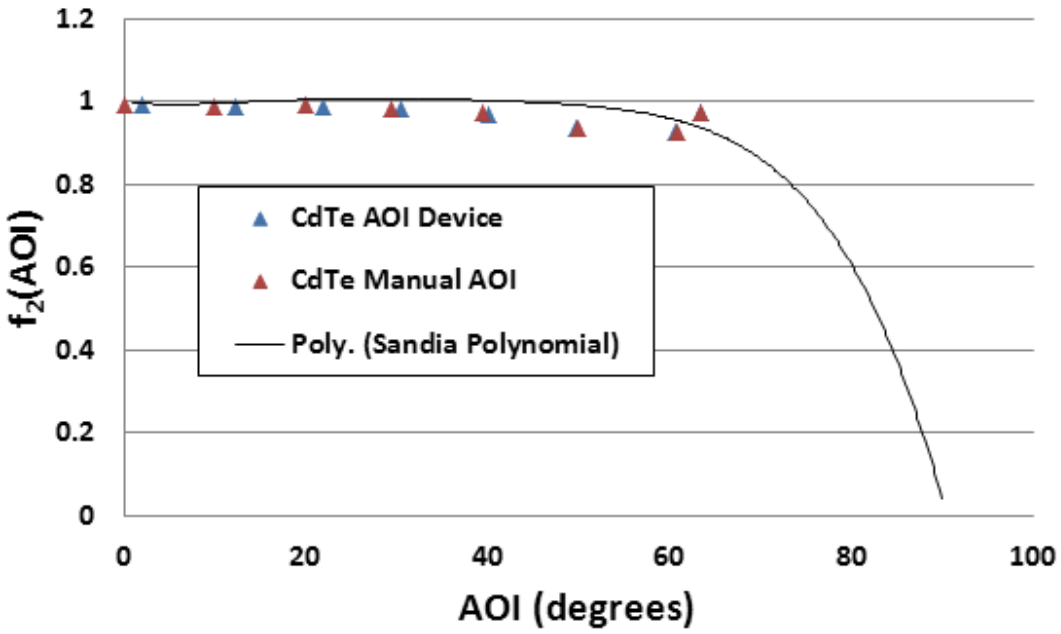

Figure B2. Comparison of relative optical responses obtained using the AOI hardware and AOI calculation for a CdTe module with glass superstrate for elevation rotation (direct to global ratio was 0.89).

For azimuth angle, the tracker was allowed to rotate to its full westward rotation angle and tracked azimuthally to the east. The azimuth angle of the module was manually measured by dividing the diameter of the tracker pole into 360° and fixing a dial to the rotating head of the tracker to indicate its change in angle. Because the azimuthal rotation of the tracker was limited, azimuth verification could only be obtained for AOI up to 63°. For elevation angle, the two-axis tracker was tilted to the maximum horizontal position of 11° (where 0° is horizontal) and tilted downward to a maximum angle of 74.5°. The f_2(AOI) data for elevation angle deviates from the generalized polynomial for higher tilt angles due to the inconsistent reflectance throughout the measurement. When the modules are at 11° tilt (close to horizontal), they "see" only the sky. As they are tilted downward, the ground reflection could interfere with the data accuracy. This phenomenon does not occur for azimuth angles because the modules are essentially seeing the same ratio of sky and ground (they were at 30° tilt angle for the duration of the azimuth rotation).

The purpose of this experiment was to verify that the manual method and AOI device measurements were consistent. Both methods proved to be accurate. The standard deviation between manually calculated AOI and the AOI device measurement for azimuth angle was 1.66°. The standard deviation between manually calculated AOI and AOI device measurement for elevation tilt was 1.08°.

Appendix C: Lessons Learned 1: Round 1 Measurements Using a Multi-Curve Tracer

The data presented in the main body of the report (the third and final round) evolved from previous two rounds of data collections and reductions. Improvements to the experimental setup and data processing were made after each round. For the first round of data collection, a DayStar (DS3200) multi-curve tracer was used to measure and record I_{sc}, module temperature, and irradiance sensor readings. The main problems concerning these measurements were:

1. The fastest time the multi-curve tracer could record and store data was one minute intervals. This was due to a software limitation of the multi-curve tracer, not a hardware issue. The multi-curve tracer saves data files onto the hard drive by automatically assigning them a file name based on the time the data was collected. The data file is named only for the hour and minute it is stored (not for the second). The physical capabilities of the tracker allow it to take data for the five modules in ten seconds. However, because the files are automatically assigned a name based on the time they were taken, the minimum time interval the data could be recorded and stored was one minute. For this experiment, the tracker was rotated by 5° AOI every one minute until it reached a maximum of 77° AOI. The experiment was performed in 16 minutes and a total of 16 data points were collected. The 16 data points in 16 minutes are sufficient to comply with the IEC 61853-2 standard, which states "for devices with rotational symmetry of the reflectivity with respect to the module normal, do a minimum of 9 different angles to span the angles from 0 to 80° for one direction." To confidently validate this statement, however, more data points were needed. Because data should be recorded as quickly as possible to reduce the spectral change during the experiment, round 2 was to be carried out using equipment that could measure and record data in less than one minute intervals.
2. The irradiance sensors used for measuring global irradiance in the plane of array (pyranometers) and direct normal irradiance (pyrheliometer) had not been calibrated, and therefore the accuracy of the measurements could not be confirmed and the uncertainty could not be calculated.
3. The relative I_{sc} obtained versus AOI plot is shown in Figure C1. Using Sandia's Equation A6, the relative optical response data—f_2(AOI) data—was plotted versus AOI as shown in Figure C2. The plotted data (symbols) was then compared to the "generic" polynomial curve (solid line) empirically derived by Sandia National Laboratories. As this figure shows, there is a significant difference between the f_2(AOI) data calculated using the experimental data and the generic polynomial curve (between 60° and 75°). This difference warranted further investigation, which revealed a human error in constructing the Equation A6 in the Excel spreadsheet. This error was fixed in the final rounds of data processing.

Nevertheless, the multi-curve tracer method, as opposed to the transducer/data logger method, was not continued for the second and third (final) rounds of measurements due to the limitation on the number of data points that could be collected during the short duration of tracker rotation.

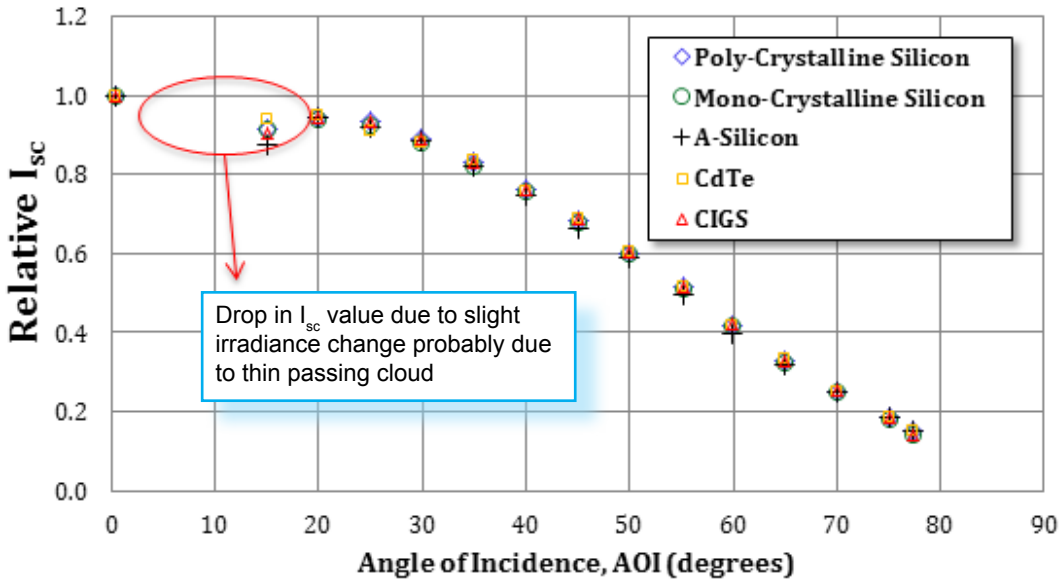

Figure C1. Round 1—Relative I_{sc} versus AOI for five modules (multi-curve tracer method).

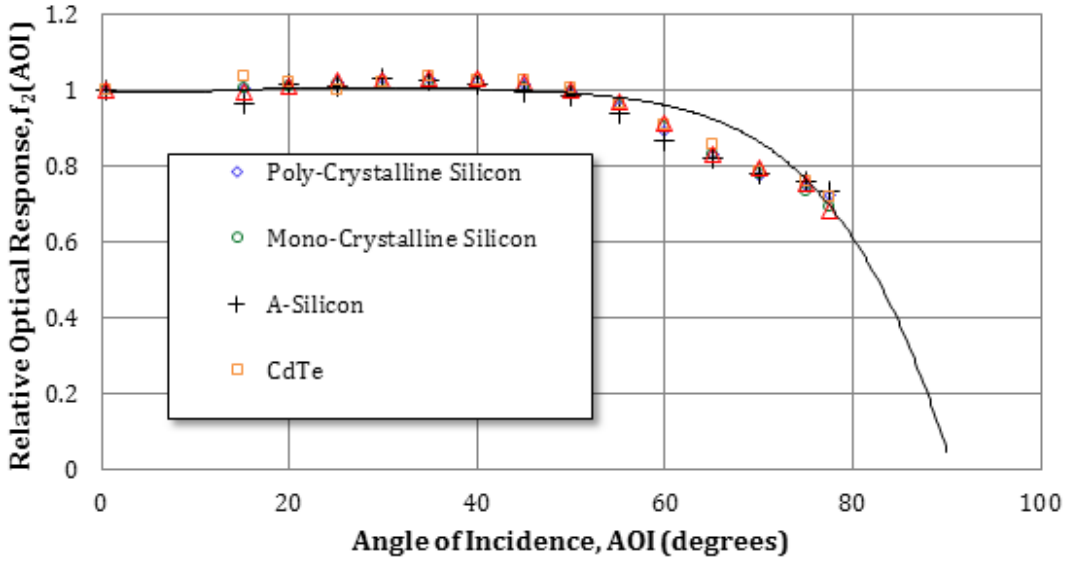

Figure C2. Round 1—Data for five modules where f_2(AOI) was erroneously calculated using Equation A6 (multi-curve tracer method).

Appendix D:
Lessons Learned 2: Round 2 Measurements Using Transducers and Data Logger

During round 2, we used CR Magnetics DC current transducers and a Campbell Scientific CR1000 data logger and multiplexer to measure and record I_{sc}, module temperature and reference cell readings. The problems apparent in round 1 were addressed in round 2:

1. The fastest time interval that the multi-curve tracer could measure and store data was one minute. For round 2, the fastest time interval that the data logger and multiplexer could store data was 30 seconds. For round 2, we collected 16 data points during the 9.5-minute experiment.
2. In round 2, we identified and corrected the human error that was present in round 1 when constructing Equation A6 in the Excel spreadsheet. Therefore, all plots presented in round 2 used the correct f_2(AOI) equation.
3. The reference devices had yet to be calibrated for this experiment. Therefore, uncertainty analysis of f_2(AOI) could not be calculated.

For round 2 measurements, the relative I_{sc} obtained versus AOI is shown in Figure D1. The plot of f_2(AOI) versus AOI, which was correctly generated using the Sandia Equation A6, is given in Figure D2.

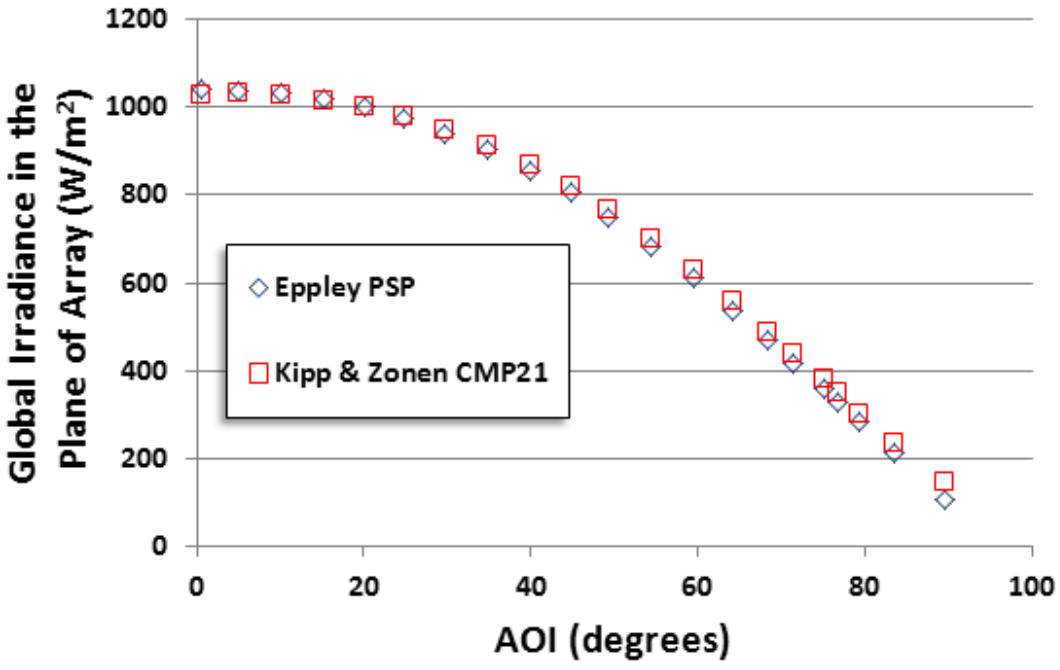

Figure D1. Round 2—Relative short circuit current versus AOI for five modules (data logger method).

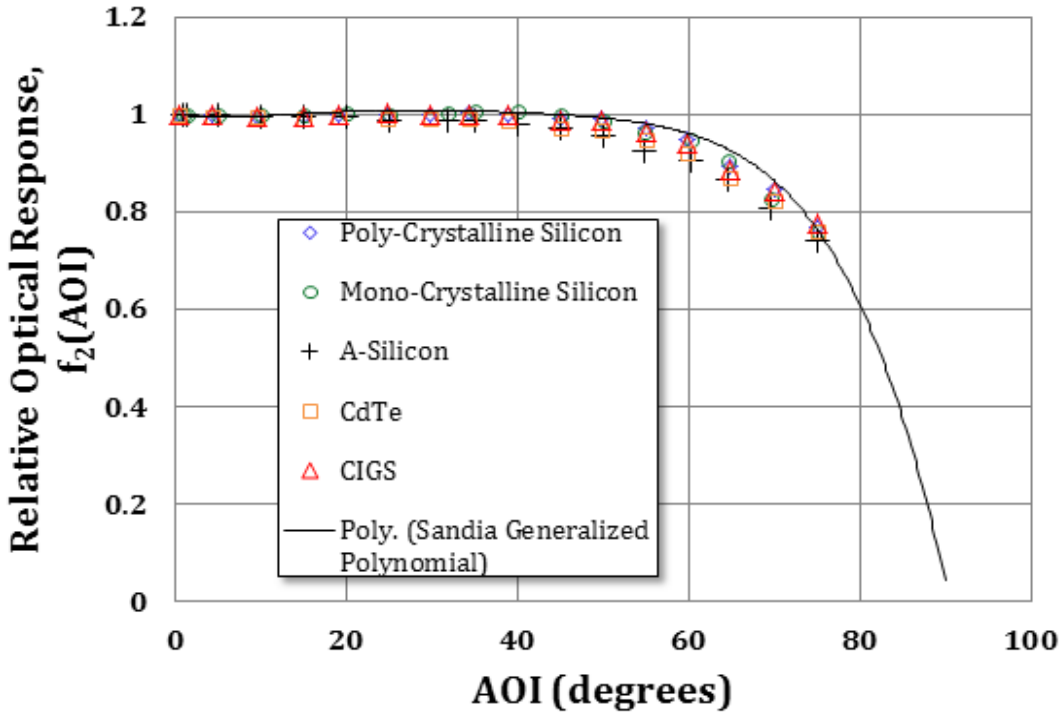

Figure D2. Round 2—Data for five modules where f_2(AOI) was *correctly* calculated using Equation A6 (data logger method).

Appendix E:
Inter-Comparison and Crosschecking of Pyranometers

For this experiment, we used a calibrated Eppley PSP pyranometer to measure global irradiance in the plane of array and cross referenced it with a Kipp & Zonen CMP21. The f_2(AOI) calculation proved to be extremely sensitive to the accuracy of the global irradiance measurements. We mounted the pyranometers coplanar to the PV modules and in positions on the tracker so that no shading of the modules or the other reference devices occurred. The E_{poa} measurements for both devices were recorded simultaneously by the CR1000 data logger and are shown in Table E1. The AOI experiment was performed on several different days with various ratios of direct normal irradiance to global irradiance (E_{dni}/E_{poa}). For each case, the standard deviation of the pyranometers' measured global irradiance in the plane of array (E_{poa}) increased as AOI increased. Figure E1 gives E_{poa} measured for both pyranometers and their standard deviation as measured for an 87 % E_{dni}/E_{poa} ratio.

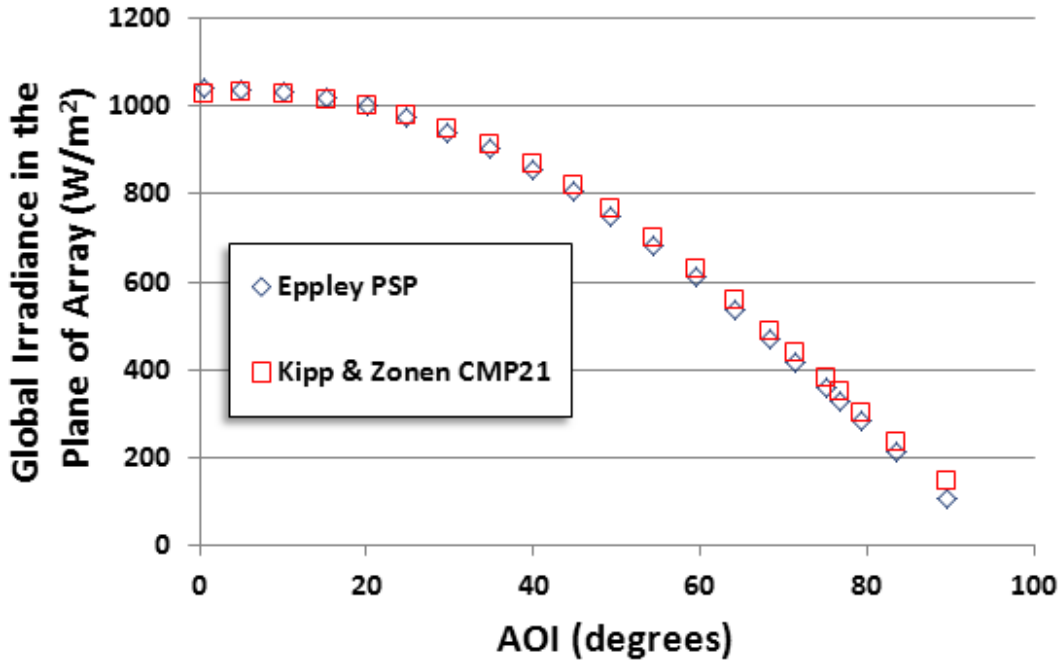

Figure E1. Global irradiance as measured by the Kipp & Zonen CMP21 and Epply PSP pyranometer for 87 % Edni/Epoa.

Table E1:
Comparison of Kipp & Zonen CMP21 Versus Eppley PSP Measured Global Irradiance in the Plane of Array for 87% Direct to Global Irradiance Ratio

88% E_{dni} to E_{poa} Ratio			
AOI (degrees)	Kipp & Zonen E_{poa} (W/m^2)	Eppley E_{poa} (W/m^2)	Difference (%)
0.6	1029.3	1038.6	0.9%
5.1	1030.3	1036.4	0.6%
10.1	1026.0	1029.5	0.3%
15.1	1015.2	1018.2	0.3%
20.2	1000.0	1000.0	0.0%
24.9	979.4	976.1	0.3%
29.8	949.1	940.9	0.9%
34.9	913.3	901.5	1.3%
39.9	868.9	854.4	1.7%
44.8	819.7	804.4	1.9%
49.2	764.8	747.8	2.3%
54.5	700.4	681.5	2.8%
59.5	629.9	610.2	3.2%
64.2	559.0	537.4	4.0%
68.3	489.3	468.4	4.5%
71.4	437.2	418.3	4.5%
75.2	381.8	359.9	6.1%
76.8	351.1	329.2	6.7%
79.4	302.6	282.5	7.1%
83.5	233.9	215.8	8.4%
89.6	146.0	109.2	33.7%

The data presented in Table E1 represents the data used in the body of this report. However, we also performed experiments for other days with various direct to global irradiance ratios. Figure E2 gives a comparison of irradiance data for a direct to global irradiance ratio of 81%. This data also shows a higher standard deviation for higher AOI. For AOI from 0° to 66° the average standard deviation is 4%, whereas for AOI from 67° to 90° the average standard deviation is 15%. Figure E3 gives a comparison of irradiance data for an overcast day where the ratio of direct to global irradiance was 2%. For this data, the standard deviation between the two pyranometers remained approximately constant, but higher, for all AOI.

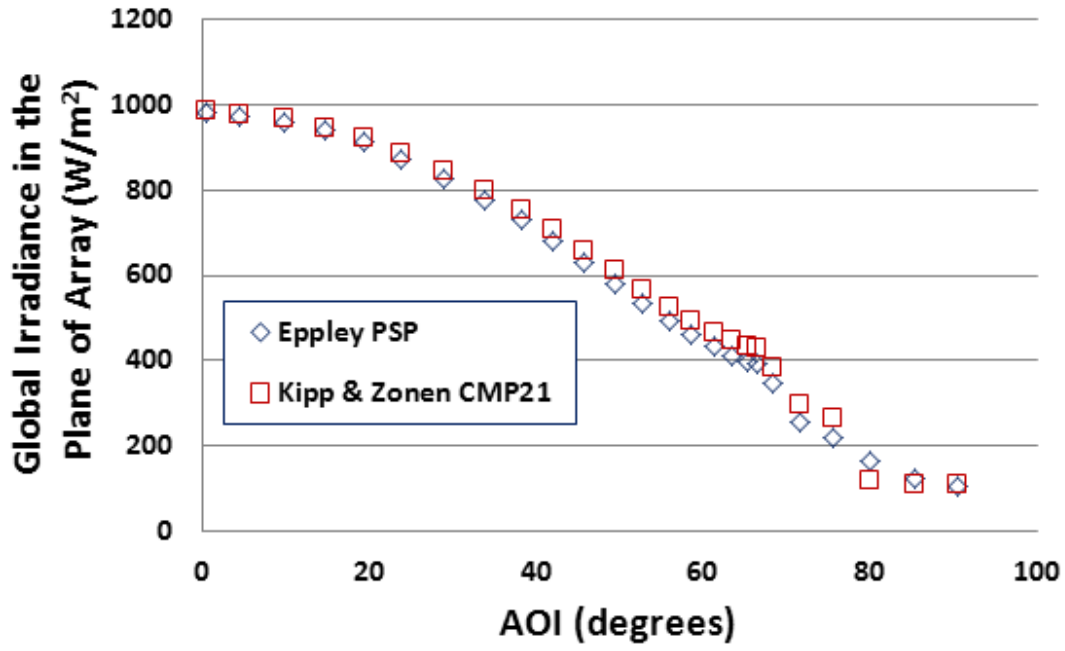

Figure E2. Comparison of Kipp & Zonen CMP21 versus Eppley PSP measured global irradiance in the plane of array for 81 % direct to global irradiance ratio.

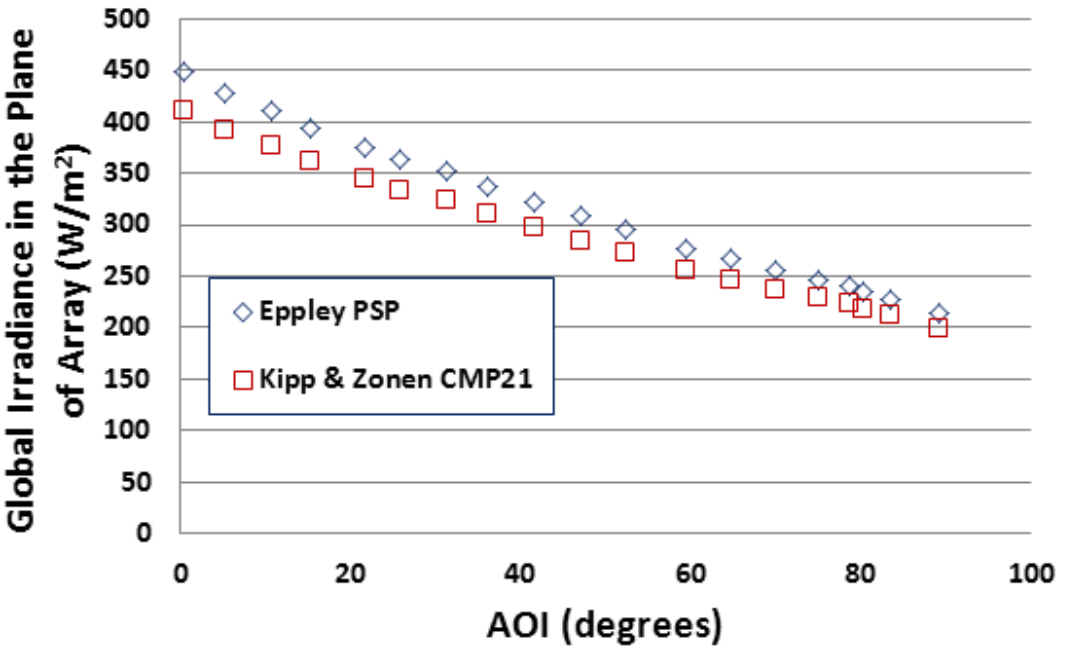

Figure E3. Comparison of Kipp & Zonen CMP21 versus Eppley PSP measured global irradiance in the plane of array for 2 % direct to global irradiance ratio.

Appendix F: Measurement of f_2(AOI) Versus AOI in the Opposite Direction

To obtain Figure 7 in the main body of this report, we collected experimental data at 14:37:30 and the tracker was rotated from the west (starting at 0.59° AOI) to the east (ending at 83.50° AOI). This experiment took 10 minutes to complete. To verify the rotational symmetry of the reflectivity with respect to module normal as called for in IEC 61853-2, the data was also collected for the five modules in the opposite direction (east to west). This experiment started at 14:47:30. The tracker was set to automatic mode and allowed to track the opposite direction (from east to west). The data was processed using Sandia Equation A6 and the corresponding graph of f_2(AOI) is given in Figure F1.

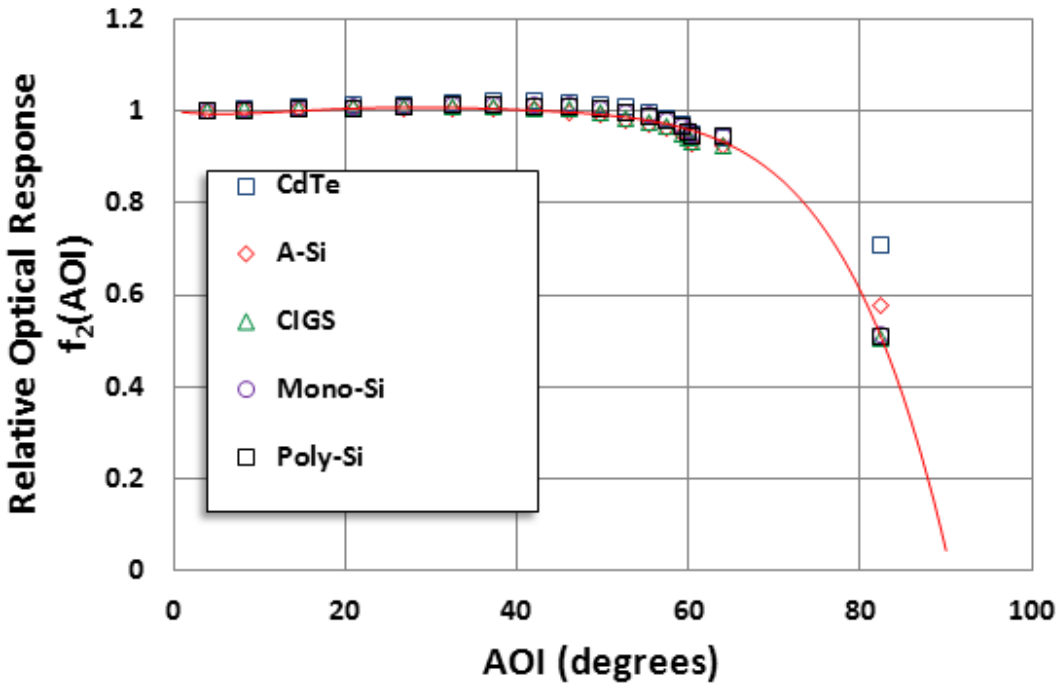

Figure F1. Round 3—Data for five modules where f_2(AOI) was calculated when the tracker was rotated in the opposite direction (east to west).

Using the automatic function to track in the opposite direction had a few disadvantages. In the manual mode, the tracker was rotated in both azimuth and elevation proportionally. However, when the tracker was set to automatic mode to track back to zero AOI, it first adjusted elevation angle, then tracked back azimuthally. This is not expected to affect the relative optical response of the module, but it does limit the number of data points collected. Tilting the tracker in elevation changes the AOI much more quickly than rotating azimuthally. Because the tracker tilted the modules in elevation for the first 30 seconds, data could only be recorded for AOI of 83° (the starting point taken at 14:37:30) and 63° (the next point taken at 14:38:00). After the tracker had adjusted its elevation angle it began tracking azimuthally, and more data points could be obtained. Figures F2 through F6 give the plots for f_2(AOI) calculated for each module technology tracking in both directions (east to west and west to east). The data for each technology is consistent for AOI when rotated in both directions from 0 to 63°.

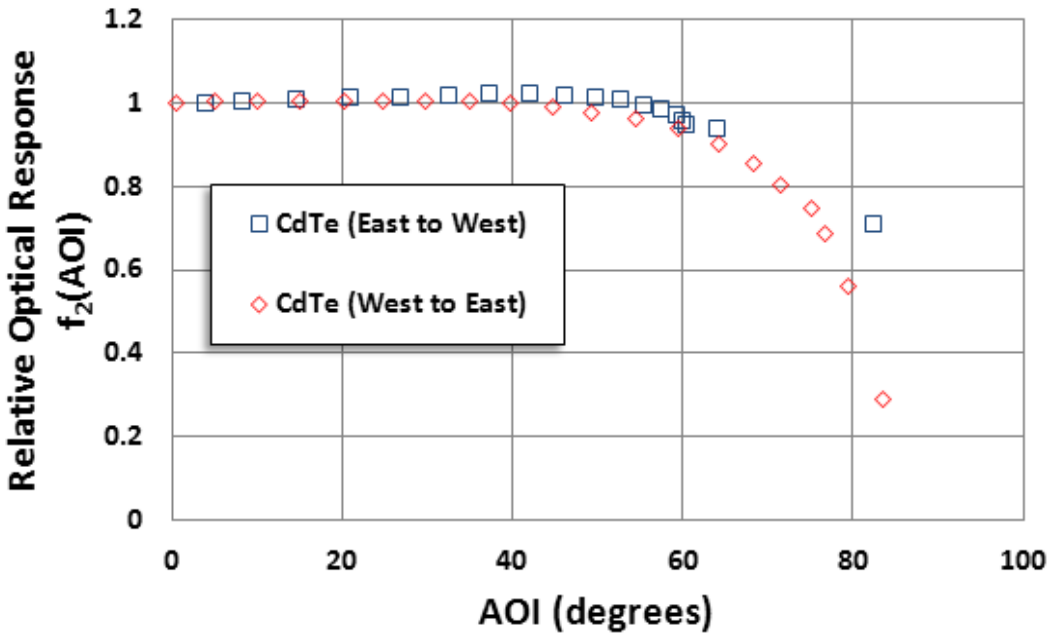

Figure F2. Round 3—Data for f_2(AOI) calculated for CdTe from west to east compared to data when the tracker was rotated in the opposite direction (east to west).

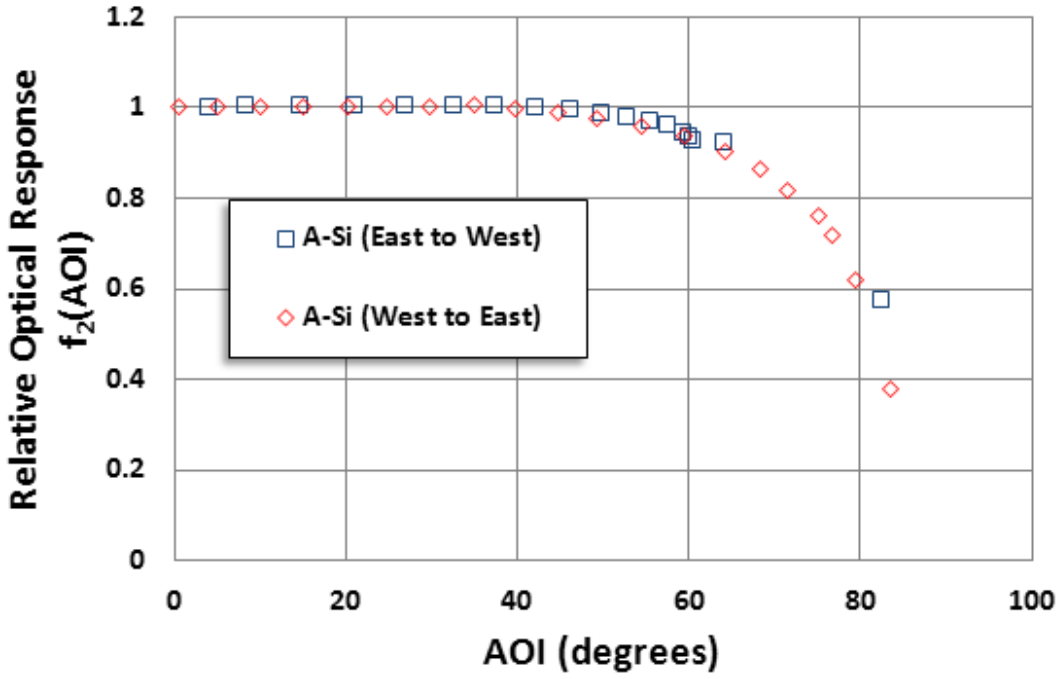

Figure F3. Round 3—Data for f_2(AOI) calculated for a-Si from west to east compared to data when the tracker was rotated in the opposite direction (east to west).

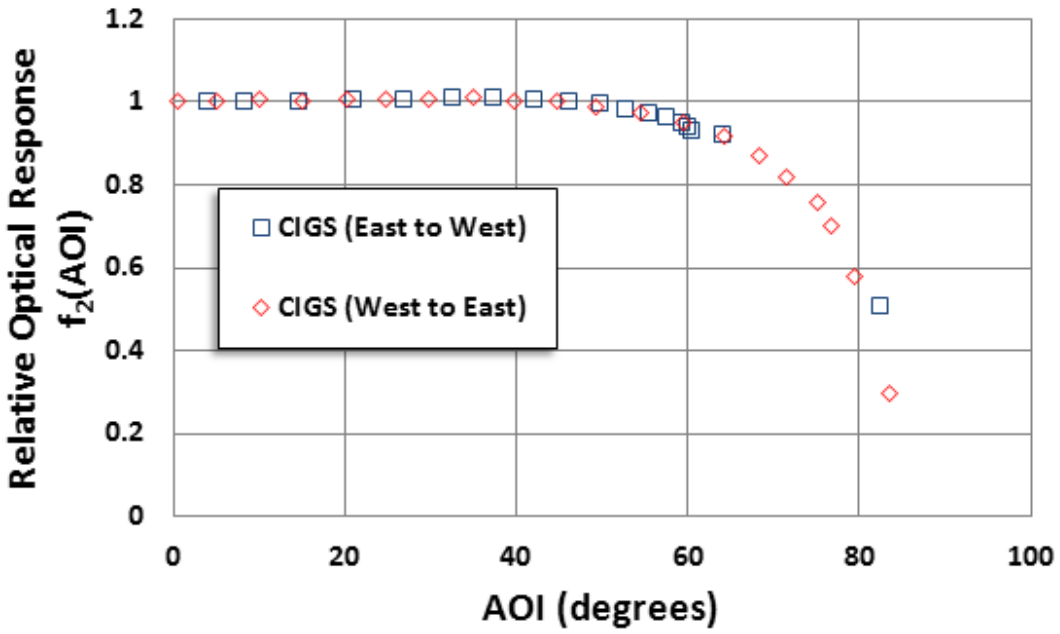

Figure F4. Round 3—Data for f_2(AOI) calculated for CIGS from west to east compared to data when the tracker was rotated in the opposite direction (east to west).

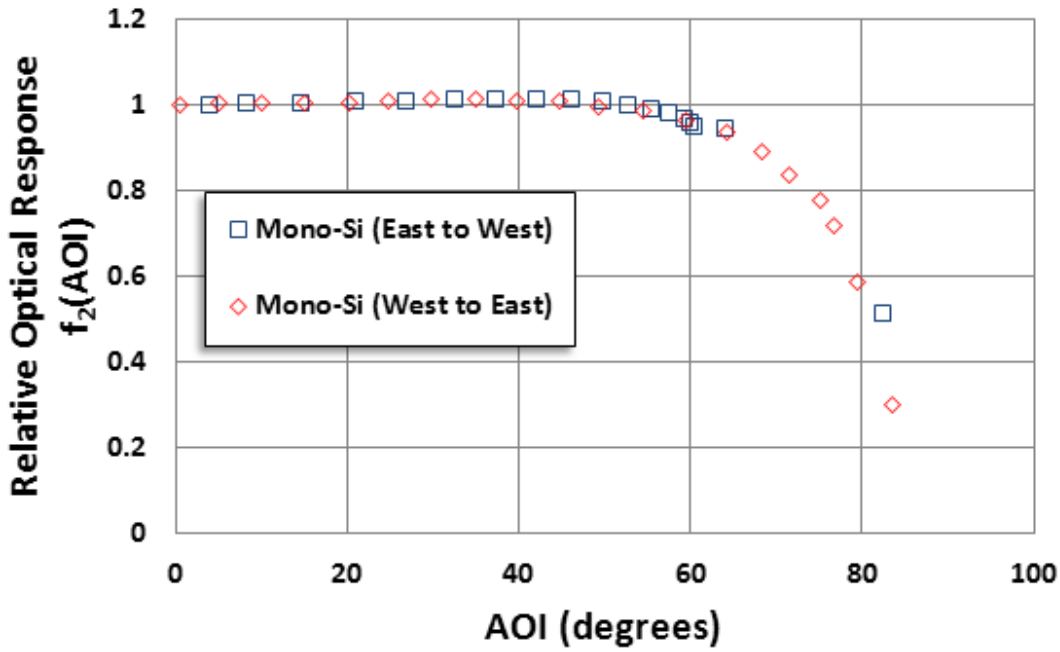

Figure F5. Round 3—Data for f_2(AOI) calculated for mono-Si from west to east compared to data when the tracker was rotated in the opposite direction (east to west).

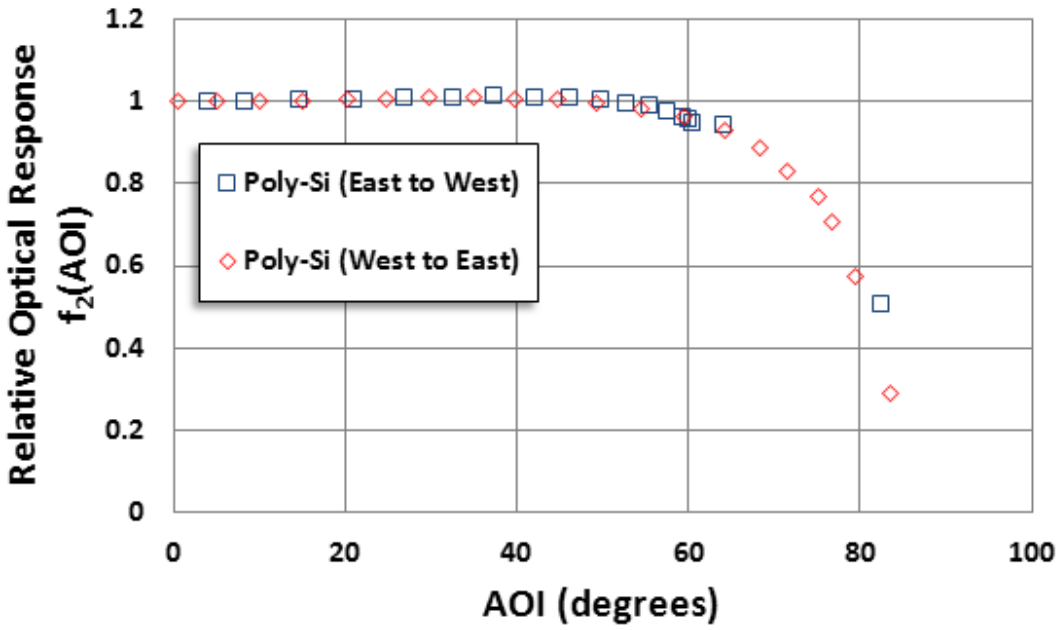

Figure F6. Round 3—Data for f_2(AOI) calculated for poly-Si from west to east compared to data when the tracker was rotated in the opposite direction (east to west).

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Proposed Updates to IEC 61853-1 Standard

Current Entire Clause 4 - Marking

Each module shall carry the following clear and indelible markings:

- name, monogram or symbol of the manufacturer;
- type or model number;
- serial number;
- polarity of terminals or leads (colour coding is permissible);
- nominal and minimum values of maximum output power at STC after preconditioning, as specified by the manufacturer for the product type (see Clause 5).

The date and place of manufacture shall be marked on the module or be traceable from the serial number.

For future production the power ratings for NOCT, LIC, HTC and LTC determined by this standard as defined in Clause 7 and Table 1 and determined via the procedure in 9.2 shall be marked on a label, or be stated in the manufacturer's literature provided with each module of this type.

Proposed Clause 4 - Marking (additions in red and deletions struck through)

Each module shall carry the following clear and indelible markings:

- name, monogram or symbol of the manufacturer;
- type or model number;
- serial number;
- polarity of terminals or leads (colour coding is permissible);
- nominal and minimum values of maximum output power at STC after preconditioning, as specified by the manufacturer for the product type (see Clause 5).

The date and place of manufacture shall be marked on the module or be traceable from the serial number.

For future production **the following determined by this standard** shall be marked on a label or be stated in the manufacturer's literature provided with each module of this type:

- the power ratings for NOCT, LIC, HTC and LTC ~~determined by this standard~~ as defined in Clause 7 and Table 1 and determined via the procedure in 9.2;
- **a table of each of the parameters I_{sc}, P_{max}, V_{oc}, and V_{max} as functions of irradiance and temperature as defined in Table 2 and determined via the procedure in Clause 8 and 9.**
- **module thermal coefficients α_1, β_1, γ_1 measured at STC.**

Current Entire Clause 6 - Report

Following completion of the procedure, a certified report of the performance tests, with measured power characteristics shall be prepared by the test agency in accordance with the procedures of ISO/IEC 17025. Each certificate or test report shall include at least the following information:

a) a title;

b) name and address of the test laboratory and location where the calibration or tests were carried out;

c) unique identification of the certification or report and of each page;

d) name and address of client, where appropriate;

e) description and identification of the item calibrated or tested;

f) characterization and condition of the calibration or test item;

g) date of receipt of test item and date(s) of calibration or test, where appropriate;

h) identification of calibration or test method used;

i) reference to sampling procedure, where relevant;

j) any deviations from, additions to or exclusions from the calibration or test method, and any other information relevant to a specific calibration or test, such as environmental conditions;

k) a statement as to whether the simplified method in section 8 was used to complete the matrix. If the simplified method was used, the test report should give the values of relative temperature coefficients for maximum power and open circuit voltage for the two different irradiances used to validate the use of the simplified method;

l) measurements, examinations and derived results, including as a minimum table 2 for I_{sc}, P_{max}, V_{oc}, and V_{max} and module thermal coefficients α_1, β_1, the average power and the values for each of the three test modules at all reference power conditions (defined in section 7) and the temperature coefficient of module power (W) at the maximum power point (γ_1);

m) a statement of the estimated uncertainty of the calibration or test result (where relevant);

n) a statement as to whether the measured STC power agrees with the manufacturer's rated power range within the test laboratories measurement uncertainty;

o) a signature and title, or equivalent identification of the person(s) accepting responsibility for the content of the certificate or report, and the date of issue;

p) where relevant, a statement to the effect that the results relate only to the items calibrated or tested;

q) a statement that the certificate or report shall not be reproduced except in full, without the written approval of the laboratory.

Proposed Clause 6 - Report (additions in red and deletions struck through)

Following completion of the procedure, a certified report of the performance tests, with measured power characteristics shall be prepared by the test agency in accordance with the procedures of ISO/IEC 17025. **While this module type is available from the manufacturer the full certificate or test report shall be provided by the manufacturer upon request.** Each certificate or test report shall include at least the following information:

a) through q) unchanged from current standard

For reference: Table 2 from IEC 61853-1

Table 2 - I_{sc}, P_{max}, V_{oc}, and V_{max} versus irradiance and temperature

Irradiance	Spectrum	Module temperature			
W-m-2		15 °C	25 °C	50 °C	75 °C
1,100	AM1,5	NA			
1,000	AM1,5				
80O	AM1,5				
600	AM1,5				
400	AM1,5				NA
200	AM1,5			NA	NA
100	AM1,5			NA	NA

Accelerated Lifetime Testing of Photovoltaic Modules

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July 2013

Solar America Board for Codes and Standards

www.solarabcs.org

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EXECUTIVE SUMMARY

Technology risk—the concern that a technology will underperform (durability) or become obsolete prematurely (reliability)—is one of the major barriers to photovoltaic (PV) diffusion and project financing. Climate-specific and technology-dependent durability and reliability are the primary determinants of PV module lifetimes.

Maximizing energy production and minimizing downtime results in the highest return on investment for PV systems and makes the technology attractive to investors and consumers. Improving durability (minimizing soft or degradative losses) maximizes energy production and improving reliability (minimizing hard or catastrophic failures) minimizes downtime.

The primary metric for PV module durability is the annual degradation rate (% degradation per year) and the primary metric for reliability is failure rates (number and duration as well as the effective influence on energy production). The purpose of accelerated testing (AT) is to assess the reliability and durability of products by inducing failures and degradation in a short period of time using accelerated test conditions much more severe than actual field operating conditions while replicating the actual field failure mechanisms.

This report does not attempt to develop a new AT methodology or to select an existing AT methodology, but rather provides a literature review and analysis of field failures, degradation, and available AT methodologies. Based on this review report and the other published literature, research teams can develop AT protocols that could be converted into an accelerated comparative testing and/or lifetime testing protocol/standard by one or more standards developing organizations or international/national industry organizations.

To generate this report, the authors collected and systematically analyzed a large number of published papers on PV module reliability and durability. This review report covers the following major topics:

- the difference between reliability and durability;
- failure and degradation modes and mechanisms of PV modules;
- accelerated stress types (including potential induced degradation), levels, and prioritization;
- pitfalls in preparing representative sample designs for accelerated stress testing;
- existing and future (potential) accelerated comparative and lifetime testing programs;
- key attributes of accelerated comparative and lifetime testing programs;
- considerations for designing and developing new accelerated comparative and lifetime testing programs;
- a possible approach for a PV rating system; and
- physical and statistical models for lifetime prediction using black-box and white-box approaches based on field degradation data and accelerated test data.

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Acknowledgments

The authors gratefully acknowledge the constructive and critical comments of Dr. Bill Marion (National Renewable Energy Laboratory [NREL]), Dr. John Wohlgemuth (NREL), Dr. Sarah Kurtz (NREL), Dr. Jennifer Granata (Sandia National Laboratories), and Mr. George Kelly (BP Solar). This material is based upon work supported by the U.S. Department of Energy under Award Number DE-FC36-07GO17034.

Solar America Board for Codes and Standards

The Solar America Board for Codes and Standards (Solar ABCs) provides an effective venue for all solar stakeholders. It consists of a collaboration of experts who formally gather and prioritize input from groups such as policy makers, manufacturers, installers, and large and small-scale consumers. Together, these entities make balanced recommendations to codes and standards organizations for existing and new solar technologies. The U.S. Department of Energy funds Solar ABCs as part of its commitment to facilitate widespread adoption of safe, reliable, and cost-effective solar technologies.

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TABLE OF CONTENTS

DISCLAIMER 2

EXECUTIVE SUMMARY 3

AUTHOR BIOGRAPHIES 4

SOLAR ABCS 4

ACKNOWLEDGMENTS 4

INTRODUCTION 6
- Need for Accelerated Lifetime Testing Program for Photovoltaic Modules 6
- Challenges in Developing Accelerated Lifetime Testing Program for Photovoltaic Modules 7
- Scope and Limitation of the Report 9

DIFFERENCE BETWEEN RELIABILITY AND DURABILITY 11
- Reliability (Failure) vs. Durability (Degradation): A Hypothetical Representation 11
- Reliability (Failure) vs. Durability (Degradation): An Actual Field Representation 12
- Plots for Failure Rate and Degradation Rate Analysis: A Hypothetical Representation 12
- Prediction of Energy Production Based on Failure Rate and Degradation Rate Data 14

PV FIELD FAILURES AND DEGRADATIONS 15
- Field Failure and Degradation Rates 15
- Field Failure and Degradation Modes 17
- Field Failure and Degradation Modes, Mechanisms, Causes, and Effects 19

PV ACCELERATED TESTING: STRESS TYPES, LEVELS, AND PRIORITIZATION 27
- Concept of Accelerated Testing for Photovoltaic Modules 27
- Types and Selection of Accelerated Tests for Photovoltaic Modules 29
  - Stress Level and Duration Limits of Accelerated Tests for Photovoltaic Modules 32
  - Stress Level and Duration Limits: Temperature 33
  - Stress Level and Duration Limits: Humidity 36
  - Stress Level and Duration Limits: UV 41
  - Stress Level and Duration Limits: Humidity-Freeze 44
  - Stress Level and Duration Limits: Voltage 44
- Prioritization of Lifetime Accelerated Tests for Photovoltaics 51
  - Prioritization From Reliability (Failure) Perspective 51
  - Prioritization From Durability (Degradation) Perspective 54
- Pre- and Post-Characterization of Materials and Modules 55

PV ACCELERATED TESTING: PRESENT AND FUTURE PROGRAMS 57
- Types of Accelerated Testing Programs 57
  - Accelerated Qualification Testing (AQT) 58
  - Accelerated Comparative Testing (ACT) 59
  - Accelerated Lifetime Testing (ALT) 60
- Key Attributes and Considerations for Designing Future ACT and ALT Programs 62

PV RATING SYSTEM: A POSSIBLE APPROACH 66

PV RELIABILITY PREDICTION: PHYSICAL AND STATISTICAL MODELS 68
- Black-Box Modeling 70
  - Field Degradation Modeling 70
  - Accelerated Degradation Modeling 81
- White-Box Modeling 85

CONCLUSIONS 88

ACRONYMS 89

REFERENCES 90

APPENDIX A: PV POWER PLANT VISUAL INSPECTION CHECKLIST 95

APPENDIX B: EVOLUTION OF MODULE DESIGN QUALITY BETWEEN 1997 AND 2011 101

APPENDIX C: SUMMARY OF COMPARATIVE TESTING PROGRAMS DEVELOPED BY VARIOUS ORGANIZATIONS 103

APPENDIX D: EQUIPMENT AND EXPERTISE NEEDED FOR PV MODULE RELIABILITY RESEARCH PROGRAM—AN EXAMPLE 105

Introduction

Need for Accelerated Lifetime Testing Program for PV Modules

The levelized cost of energy (LCOE, $/kWh) of photovoltaic (PV) modules is dictated not only by the initial price of the modules (dollars per watt), but also by the reliability (distribution of surviving units over time) and durability (distribution of degradation rates over time) of the modules. Just a few failed modules (reliability) or underperforming modules (durability) can have a serious negative impact on both string level and system level performance.

Standards & Poor's is a global authority in credit quality and it identifies eight finance criteria for utility-scale PV projects (Standard & Poor's, 2009). Two of the criteria are technical criteria and the others are non-technical criteria. The technical criteria are based on technology reliability and resource availability. The Standards & Poor's report indicates that all of the PV technologies rely on accelerated testing (AT) for measuring and claiming useful lives of approximately 25 years.

Similarly, in February 2012, a Credit Suisse Equity Research Report indicates that (Credit Suisse, 2012): "Product quality in our view is THE MOST SIGNIFICANT metric for a solar companies' long-term survivability." A Web page article published by Burgess in the April 2012 issue of *Renewable Energy World* also notes the following on the importance of reducing the degradation rate over the lifetime of PV systems (Burgess, 2012):

> In a world where large solar assets are built with 80 percent debt leverage or more, a one percent change in output can equate to a 10 percent change in the ROI [return on investment] for the investors. The impact of an unanticipated drop in the performance ratio from 0.80 to 0.66 would probably wipe out any anticipated return from the project. This potential future variability has a major impact on site financial viability, but more importantly on the attractiveness of solar as an investable asset class. A key objective of the industry should be to increase the entitlement level for Performance Ratio beyond the 0.80 level and reduce the long-term risk of assets drifting off that entitlement level. This would: reduce the overbuild and hence initial capital outlay; reduce the levelized cost of electricity for the site; increase the ROI for the investors; and reduce the long-term financial risk, thus attracting financial backing and possibly reducing insurance premiums.

In addition, Solarex published a paper entitled "Testing Modules for Warranties" in 1993 (Wohlgemuth, 1993) that states: "The longer a module continues to produce electricity the greater will be its value to the customer. Failure of a large number of modules while still under warranty would impose a large financial burden on the manufacturer."

By reviewing and analyzing the results of these and other sources, this Solar America Board for Codes and Standards (Solar ABCs) report communicates and emphasizes the importance of AT for predictably assessing the reliability (failures) and durability (degradation) issues related to the lifetime of PV modules in the field. The LCOE of PV systems shown in Figure 1 is primarily dictated by site solar resource, the annual degradation rate of PV modules, and the inverter replacement price (U.S. Department of Energy, 2012). It is well known that failure rates are much higher for inverters than for PV modules. Surprisingly, however, the energy production (and hence LCOE) of the overall system during its lifetime is not strongly sensitive to variations in

inverter failure rate or inverter disturbances compared to the degradation rates of PV modules because of the quick replacement or repair of failed inverters (Collins et al., 2009).

The manufacturer warranty period typically exceeds 20 years for crystalline silicon modules and 15 years for thin-film modules. Unfortunately, there is little or no systematically field monitored data or independent accelerated test data available to support most of these warranty claims. Investors, financiers, power purchasing agreement companies, and consumers are now expecting objective substantiations for these warranty claims. The PV module components, including cells and polymeric materials, must be protected from degradative losses (soft/durability losses) and catastrophic failures (hard/reliability failures) caused by stresses including temperature, humidity, ultraviolet (UV) radiation, wind, hail, and high system voltages, as well as effects including corrosion, broken interconnects, hotspots, delamination, and encapsulant discoloration.

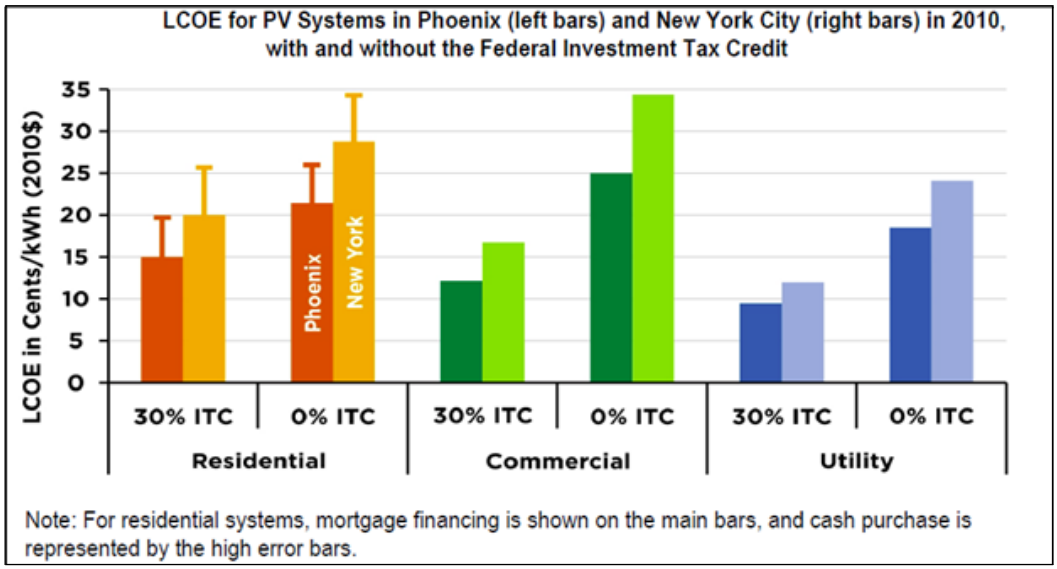


Figure 1: LCOE of PV systems in Phoenix and New York (U.S. Department of Energy, 2012).

Challenges in Developing an Accelerated Lifetime Testing Program for PV Modules

The anticipated lifetime of PV modules spans several decades. The construction materials and design are constantly changing to reduce LCOE, and the stakeholders cannot wait for decades to identify the failure modes and mechanisms of these new modules. The purpose of accelerated lifetime testing (ALT) for PV modules is to shorten the test time by using specified test conditions, which are more severe than the actual field operating conditions, to simulate actual field failure modes and mechanisms. As shown in Figure 2, only 4% (7 gigawatts [GW]) of the modules were installed before 2007, 38% (62 GW) were installed between 2007 and 2011), and 58% (95 GW) are expected to be installed between 2012 and 2015 (EPIA, 2012). Therefore, the required actual failure data and degradation data to develop an appropriate ALT program has to come from the field data of the 4% modules that were installed before 2007. Only a tiny fraction of the module data from the 4% modules (installed before 2007) is available for the degradation data analysis (due to availability of metered kWh data), however. In addition, little or no data from that 4% of modules is available for the failure analysis because there are only a few sustained event logs available for failures and replacements.

If the construction materials and design of the 4% of modules produced before 2007 are the same as those produced between 2007 and 2011 and those that will be produced between 2012 and 2015, then developing AT programs for the newer modules based on the old modules' field failure and degradation data becomes reasonably simple. However, this is based on the assumption that statistically significant field failure data and field degradation data are available from a large number of PV systems installed in varied (hot-dry, hot-humid, and hot-cold [temperate]) climatic conditions. The development of a lifetime AT program for newer modules becomes very challenging if the construction materials and design are not the same (as is often the case now) and if the changes are projected to significantly influence (positively or negatively) the field failure and degradation rates based on some preliminary AT such as accelerated qualification testing. Various AT programs developed by the industry are extensively discussed in the later sections of this report.

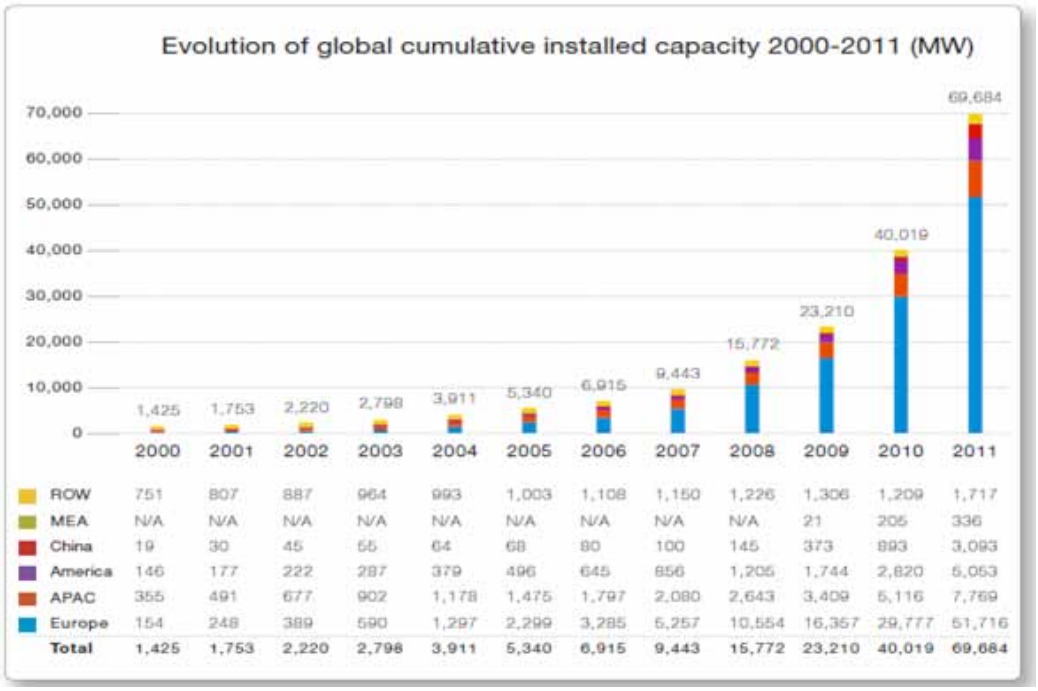


Figure 2: Only 4% (7 GW) of the modules had been installed before 2007, leading to only very minimal long-term field data availability for the reliability evaluations (EPIA, 2012).

To reduce the cost and keep up with the product development pace of ever-evolving new materials and designs, accelerated tests need to be carried out with minimum sample size and at the shortest testing time. The reliability and durability data obtained from accelerated tests should allow PV module manufacturers to predict product lifetimes and build confidence in their warranty periods. Unfortunately, as experimentally determined (Wohlgemuth, Cunningham, Amin, Shaner, Xia, & Miller, 2008), a large number of modules (eight out of ten models from various manufacturers studied in this work) appear to be currently designed and manufactured just to meet the pass requirements of qualification standards of International Electrotechnical Commission (IEC) 61215 and IEC 61646 (IEC 61215, 2005; IEC 61646, 2008).

The qualification tests are not meant to test PV modules for the end-of-life (wear-out) failure mechanisms, but they do an excellent job of identifying design, materials, and process flaws that are likely to lead to premature failure (infant mortality)

(Wohlgemuth, 2012a). The qualification testing involves a set of well-defined accelerated stress tests (irradiation, environmental, mechanical, and electrical) with strict pass/fail criteria based on extended functionality/performance, minimum safety/insulation, and detailed visual requirements. The qualification testing does not, as anticipated, identify all the possible actual lifetime/reliability field failures, but it does identify the major/catastrophic design quality issues that would initially occur in the field. The type, extent, limits, and sequence of the accelerated stress tests of qualification standards have been stipulated with two goals in mind—accelerate the same failure mechanisms observed in the field without introducing other unknown failures that do not occur in the field and induce/accelerate these failure mechanisms in a reasonably short period of time, say 60-90 days, to reduce testing time and cost.

A background literature review of the history of qualification testing and on the failure rates in the qualification testing programs is available elsewhere (Osterwald & McMahon, 2009; TamizhMani et al., 2012). Therefore, it may be concluded that the qualification tests are the minimum requirements to initiate comparative or lifetime/reliability testing, but they cannot be considered as lifetime or reliability tests because they do not cover the failures related to wear-out mechanisms. In other words, the modules that do not meet the qualification testing requirements may not be considered for comparative or reliability testing. Various challenges in developing ALT are presented in later parts of this report.

Scope and Limitation of the Report

A history of the development of PV AT programs by various organizations has been reviewed and reported in an earlier publication (Osterwald & McMahon, 2009). This Solar ABCs report is the result of an extensive background literature review on the following major topics for PV modules:

- difference between reliability and durability;
- field reliability/hard failures;
- field durability/soft losses;
- general AT programs for PV modules including
  - types/limits of accelerated tests,
  - failure modes/mechanisms, and
  - pre- and post-characterization of materials and modules;
- specific AT programs for PV modules including
  - qualification testing,
  - comparative testing,
  - lifetime testing, and
  - potential reliability testing protocols); and
- physical and statistical models for lifetime prediction of PV modules.

Because most of the long-term field and accelerated test data are available only for crystalline silicon modules, the technology specific reliability issues related to thin-film modules are not discussed in this report. Neither does this report attempt to provide any standardized accelerated comparative or lifetime testing protocol for PV modules. Rather, this report reviews and analyzes hundreds of publications and presentations, the major sources of which include:

- *Progress in Photovoltaics* (http://onlinelibrary.wiley.com/journal/10.1002/(ISSN)1099-159X),
- IEEE Photovoltaic Specialists Conference (www.ieee-pvsc.org),
- European Photovoltaic Solar Energy Conference (www.photovoltaic-conference.com),
- International Quality Assurance Forums (www.nrel.gov/ce/ipvmqa_forum),
- Photovoltaic Reliability Workshops (www.nrel.gov/pv/pvmrw.html),
- Jet Propulsion Laboratory (JPL) Reports (http://www2.jpl.nasa.gov/adv_tech/photovol/summary.htm), and
- Arizona State University Course Material (titled "Reliability and Standards of Photovoltaics").

Based on the review in this report, standardized accelerated comparative and/or lifetime testing protocols may be developed that in turn may potentially be considered for and converted into a test standard by national and/or international standards development organizations.

DIFFERENCE BETWEEN RELIABILITY AND DURABILITY

Reliability (Failure) vs. Durability (Degradation): A Hypothetical Representation

The term "reliability" for PV modules may be defined multiple ways. The ultimate definition of PV system reliability with storage may be described as "the lights go on when the switch is flipped" (Kurtz & Granata, 2009). A reliable PV module may also be defined as a PV module that has a high probability of performing its intended function adequately for 30 years under the operating conditions encountered (McMahon, Jorgensen, Hulstrom, King, & Quintana, 2000). For simplicity, it may be said that a PV module fails to provide service if its power output decreases by more than 30% after 30 years in its use environment. Also, "a high probability" means that 95% of the modules in the field will achieve this success. By "use environment" it is meant any and all use environments that the PV module will experience during service. Site meteorology, handling, and installation are included in use-environment considerations.

If the PV modules are removed (or replaced) from the field before the warranty period expires due to any type of failure, including power drop beyond warranty limit, then those failures may be classified as hard failures. In other words, all failures that qualify for warranty returns may be called a reliability failure. If the performance of PV modules degrades but still meets the warranty requirements, then those losses may be classified as soft losses or degradative losses. Toward the end of the module's life, multiple degradative mechanisms may develop and lead to wear-out failures due to accelerated degradative losses. The durability losses (and wear-out failures) and reliability failures can be hypothetically represented as shown in Figure 3. Overall, durability losses may be defined as degradative losses that meet the warranty requirements and the reliability failures may be defined as catastrophic and wear-out failures that do not meet the warranty requirements.

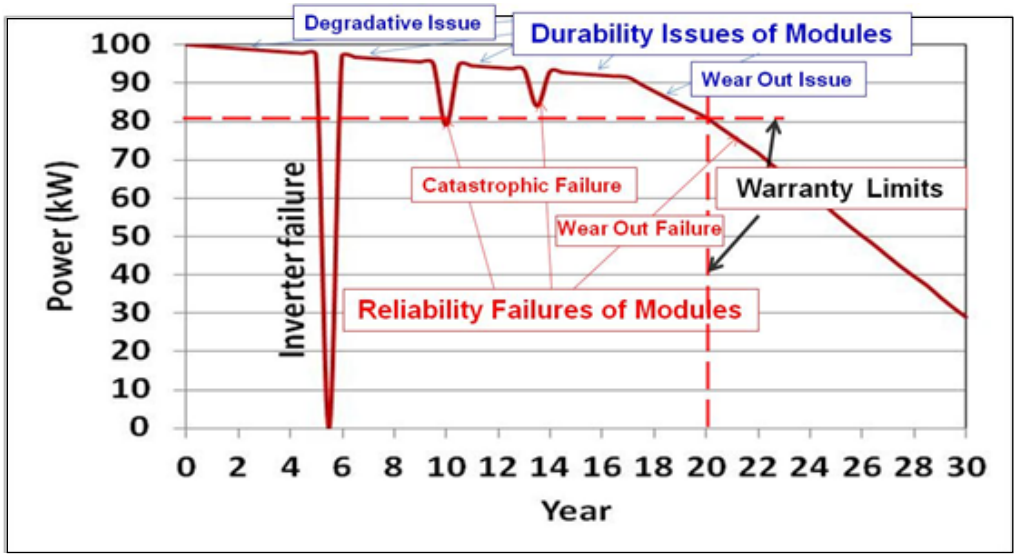


Figure 3: Reliability (failures) and durability (degradative) issues of PV modules—hypothetical plot.

Reliability (Failure) vs. Durability (Degradation): An Actual Field Representation

The hypothetical plot in Figure 3 shows durability losses and reliability failures of PV modules that can graphically be explained using actual field data shown in Figure 4. Figure 4 presents results obtained from 204 modules (composed of 53 different designs) field stressed over 18-22 years (Sample, 2011). Assuming all these modules are given a warranty of 20% maximum degradation over 20 years, about 34 modules have experienced reliability failures and the rest have experienced durability losses. Out of 34 reliability failed modules, four modules have experienced catastrophic delamination failures, six modules have experienced catastrophic diode (shorting) failures, and the other 24 modules have experienced cell and/or circuit wear-out failures.

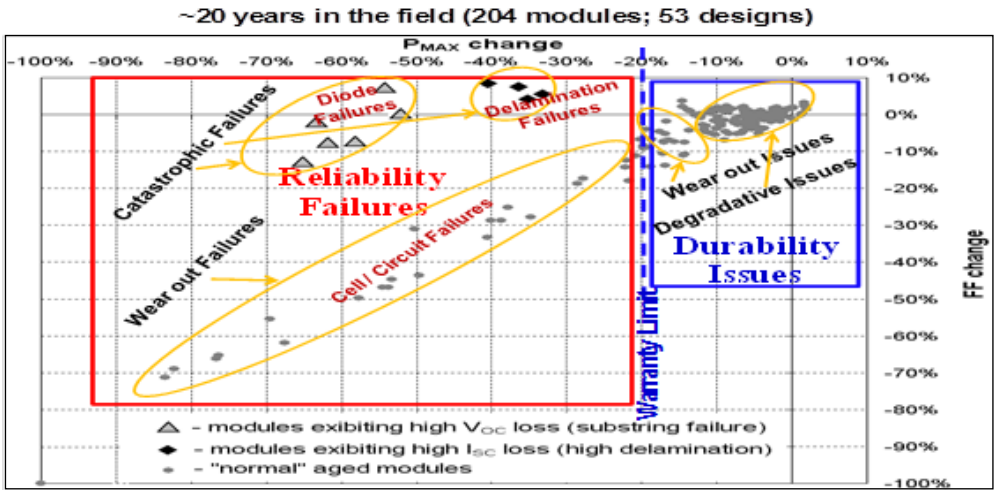


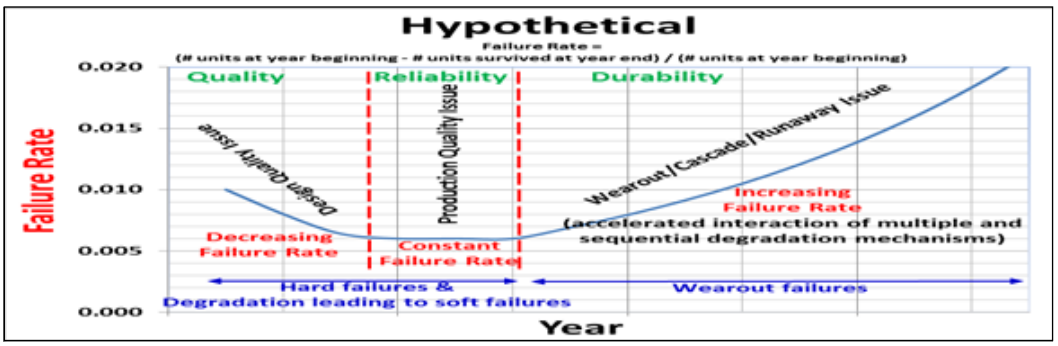
Figure 4: Reliability (failures) and durability (degradative) issues of PV modules—actual field data (figure based on data from Sample, 2011).

Plots for Failure Rate and Degradation Rate Analysis: A Hypothetical Representation

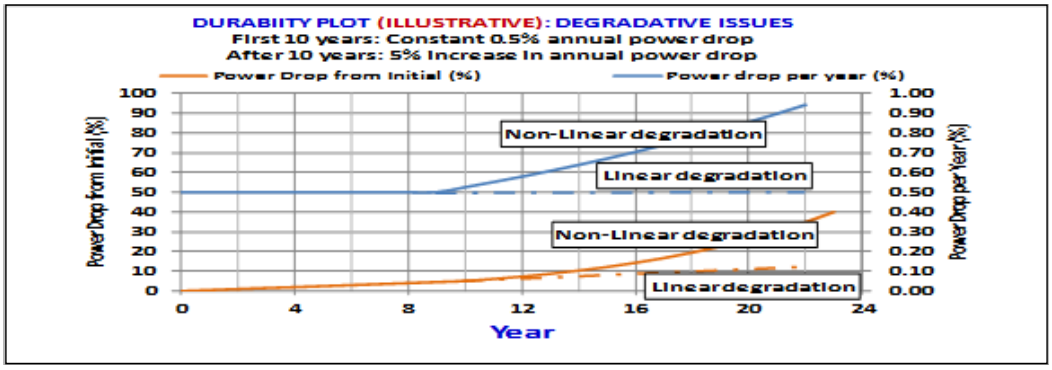
The reliability (catastrophic and wear-out) failures and durability (degradative and wear-out) losses of PV modules may be segregated and generalized using the hypothetical/illustrative plots shown in Figure 5A and Figure 5B. Failure rate is defined as the percentage of units failing per unit of time. In Figure 5A, the cause for the catastrophic failures could be attributed to the design quality (infant failures; decreasing failure rate) and production quality (useful life failures due to compounded design and production quality issues; constant failure rate) whereas the cause for the wear-out failures (end of life failures due to compounded design and production quality issues along with wear-out issues; increasing failure rate) could be attributed to the interaction of multiple degradative mechanisms accelerated by the catastrophic failures. For example, the corrosion degradative mechanism may be accelerated by the catastrophic delamination failure. The onset and slope of wear-out failures are dictated by the robustness of design quality and tolerance tightness of production quality. If there are workmanship issues, then there may be a few occasional spikes in the constant failure rate regime of the plot shown in Figure 5A. The data corresponding to these occasional spikes should not be considered in the statistical lifetime prediction, as the failure mechanisms corresponding to these spikes do not represent the normal degradation mechanisms of the product before the onset of the wear-out mechanisms, which are caused by the combination of multiple normal degradation mechanisms.

The lifetime energy production is heavily dictated by the degradation rate and this rate could be linear or non-linear depending on the failure mechanism. The Jet Propulsion Laboratory assigned a constant degradation rate for certain mechanisms and a linearly increasing degradation rate for the other mechanisms (Ross, 1984). In Figure 5B, the cause for the linear degradative failures in the first few years of operation in hot and humid climatic conditions could be attributed, for example, to fewer solder bond thermal fatigue failures and the non-linear degradative failures in the last few years of operation could be attributed to failures of additional solder bonds as failure of one bond puts more stress on others.

This hypothetical plot basically indicates that the non-linear degradation mechanism may happen right from the beginning of module installation but at a lower rank order as compared to the higher order linear degradation mechanism. However, the non-linear mechanism becomes dominant after several years of operation—10 years, for example—in the field. A recent literature review on the degradation rate of PV modules (Jordan & Kurtz, 2011) finds that "The median rate for exposure length up to 10 years is significantly higher than for studies of 10 years and longer." This investigation may seem to indicate that there could be a non-linear degradation of PV modules during 20+ years of field operation. However—as cautiously noted by the authors—this non-linearity might be due to the fact that modules with high degradation rates are unlikely to be left in the field and reported on as many times as modules with low degradation rates. Simple assumptions of a uniform and linear 0.8% degradation rate per year may or may not be valid and will need to be investigated carefully, especially when a significant number of higher degradation modules are removed in the early years, leaving the lower degradation modules.



(A)



(B)

Figure 5: Hypothetical representation of failure rate (A) and degradation (B) loss of PV modules.

Prediction of Energy Production Based on Failure Rate and Degradation Rate Data

The energy production in a specific year is basically dictated by the number of modules that survived in that year (reliability) and the performance level of the survived modules in that year (durability). The reliability and durability factors can be determined using the above plots and they can be used to calculate the annual or lifetime energy production by these modules using the following equations:

$$\text{Daily energy} = E_d = \sum_{h=1}^{h=24} E_h$$

$$\text{Annual energy} = E_a = \sum_{d=1}^{d=365} E_d$$

$$\text{Lifetime energy (for 20 years)} = E_L = \sum_{y=1}^{y=20} Ea$$

Hourly energy = E_h = Hourly Power x Hourly Durability Factor x Hourly Reliability Factor

For example:

Hourly Power = If hourly irradiance and module temperature are known or calculated (from ambient temperature, irradiance, and wind speed), then pick peak power (P_{max}) data for that irradiance and temperature from P_{max} matrix from IEC 61853-1 testing (IEC61853-1, 2011).

Hourly Durability Factor = 1 for y-1 hours; 0.995 for y-2 hours; 0.990 for y-3 hours; and so on for y-20 hours

Hourly Reliability Factor = number of samples survived (n for y-1 hrs, n-4 for y-2 hrs, n-? for y-20 hrs)

Summary—Reliability vs. Durability: If the PV modules are removed (or replaced) from the field before the warranty period expires for any types of failures, then those failures may be classified as reliability issues. If the performance of PV modules degrades but still meets the warranty requirements, then those losses may be classified as durability issues. Both reliability and durability issues are illustratively explained for both hypothetical and actual field scenarios.

PV FIELD FAILURES AND DEGRADATIONS

Field Failure and Degradation Rates

Table 1 is generated primarily from information in a paper published by Sandia (King, Boyson, & Kratochvil, 2002). As shown in Table 1, the performance loss of a grid-tied PV system could be caused by various non-failure factors and non-module degradation factors. In order to accurately determine and report the annual degradation rates and mismatch of PV modules, it is extremely important to isolate and remove the influence of all other factors. Another recent study carried out by Sandia serves as a good example of how to isolate and remove the influence of all the factors (which are not related to module durability issues) that determine module degradation rates (Granata, Boyson, Kratochvil, & Quintana, 2009). As shown in Figure 6, the module degradation rate can be as high as 4 %/year, but the median and average degradation rates are only 0.5 %/year and 0.8 %/year, respectively (Jordan & Kurtz, 2011).

Table 1

De-Rating Factors Involved in the Energy Production of Grid-Tied PV Systems (based on data from King, Boyson, & Kratochvil, 2002)

Influence of Module and System Level Factors on AC-Energy Production		
Factor	**Range (%)**	**Issue**
Module orientation	-25 to +30	Installation issue
Array utilization losses (MPPT)	-30 to -5	Inverter issue
Module power specification	-15 to 0	Performance overrating issue
Module temperature coefficients	-10 to -2	Performance issue
Module (array) degradation (%/yr)	-7 to -0.5	Durability Issue
Module Vmp vs. Irradiance	-5 to +5	Performance issue
Module soiling (annual average)	-10 to 0	Site and tilt angle issue
Angle-of-incidence optical losses	-5 to 0	Performance issue
Module mismatch in array	-5 to 0	Durability variation Issue
Solar spectral variation	-3 to +1	Performance issue

Note: MPPT is maximum power point tracking; Vmp is voltage at maximum power point.

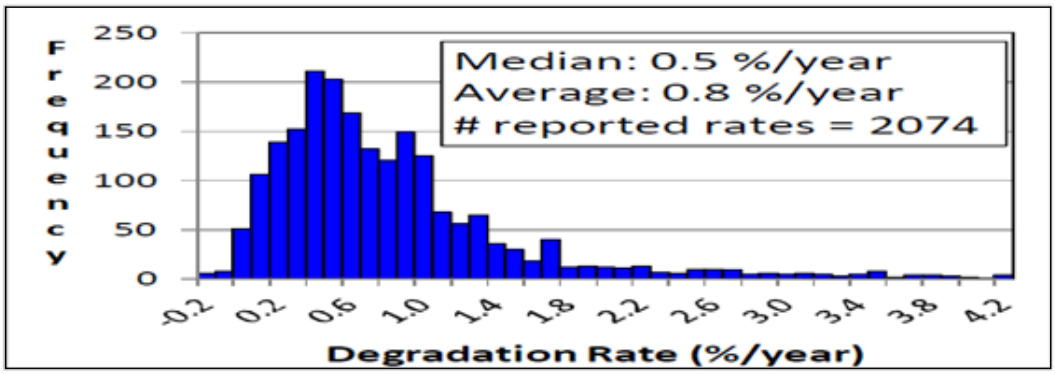


Figure 6: Annual degradation of PV modules based on 2074 reported data (Jordan & Kurtz, 2011).

The list of the module failures presented in Table 2 may seem to be very long, but in reality the crystalline silicon modules have a very impressive track record with only negligibly small field failure issues and warranty returns. As shown in Figure 7, most of the PV systems fail not due to modules but due to inverters (IEA-PVPS-TASK2, 2007).

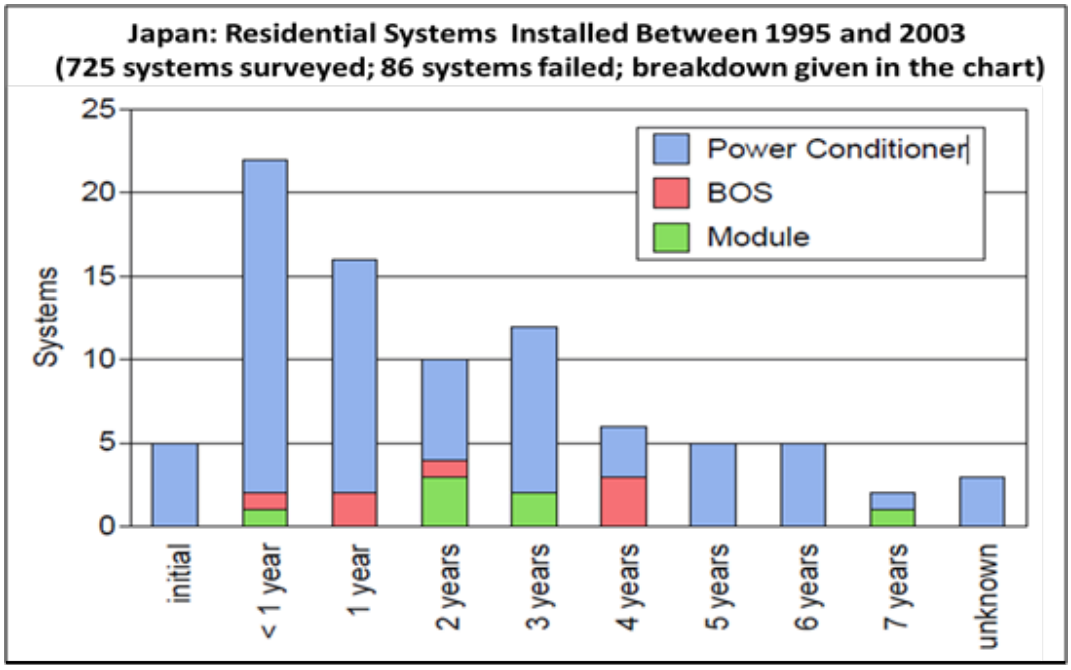


Figure 7: Failure rates of inverters, modules, and balance of system (BOS) in residential PV systems (IEA-PVPS-TASK2, 2007).

As noted earlier in this report, the inverters are replaced or repaired in a short period of time with less impact on lifetime energy production of the PV systems. The temporary energy production loss due to inverter failures during the lifetime of PV systems would be much less than the permanent energy production loss due to higher degradation rates of PV modules. The impact of higher degradation rate on the lifetime (and energy production) of PV modules would be dramatic, as shown in Figure 8 (Osterwald & McMahon, 2009).

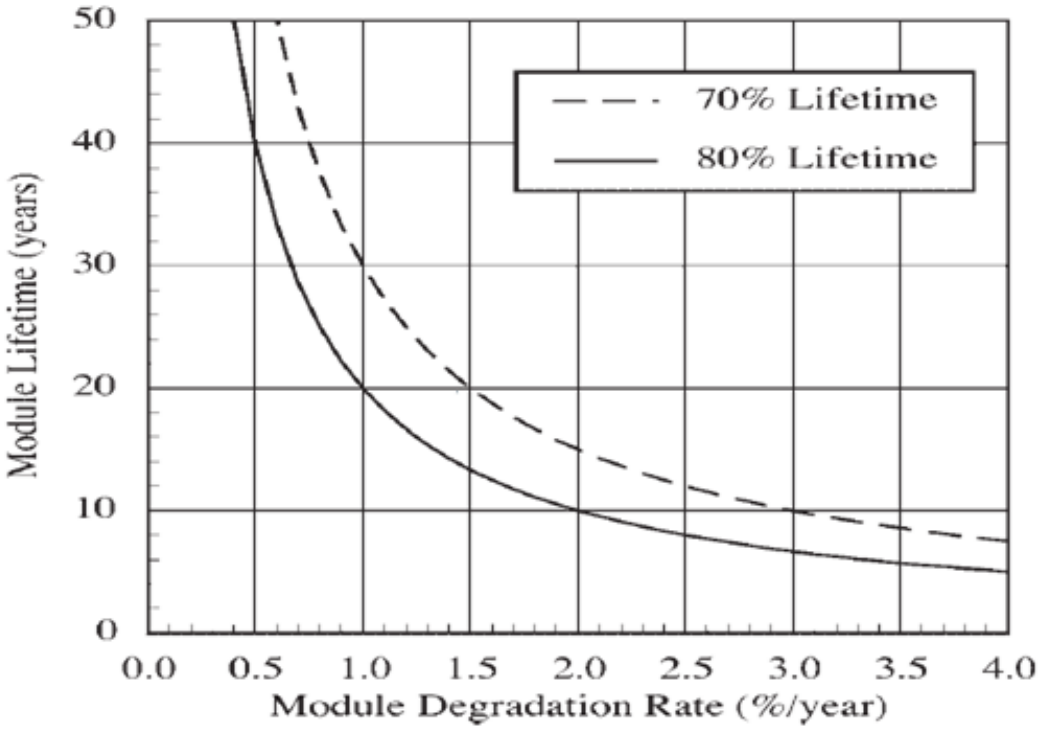


Figure 8: Serious impact of higher degradation rate on the lifetime of PV modules (Osterwald & McMahon, 2009).

Based on various publications, Wohlgemuth summarized recently reported field failure and warranty return rates for crystalline silicon modules (Wohlgemuth, 2012) as follows:

- less than 0.1 % of annual field failure rate on 10-year-old qualified (per qualification standards) modules,
- 0.005 % of annual field failure rate on up to 5-year-old modules (only six module failures out of 125,000 modules from 11 different manufacturers),
- 0.13 % warranty return rate on 1994-2005 modules (one failure every 4200 module-years of operation), and
- 0.01 % annual return rate on 2005-2008 modules.

Therefore, it may be concluded that the lifetime of PV modules is typically dictated by the degradation rates rather than failure rates. However, it is to be noted that the multiple failure modes over time could have cumulative influence on the degradation rates of the PV modules. For example, cracked cells and failed bypass diodes can electro-thermally accelerate degradation rates.

Summary—Field Failure and Degradation Rates: The degradation rate can be as high as 4 %/year but the median and average degradation rates are only 0.5 %/year and 0.8 %/year, respectively. Reports in the literature suggest that failure rates typically range between 0.005 % and 0.1 % per year depending on the duration of the modules in the field. The temporary energy production loss due to inverter failures during the lifetime of PV systems would be much less than the permanent energy production loss due to higher degradation rates of PV modules.

Field Failure and Degradation Modes

Failure and degradation modes and mechanisms of PV modules are dictated by their design/packaging/construction and the field environment in which they operate. As shown in Figure 9, the design/construction of PV modules has gone through a dramatic change since 1975 (Ross, 2012). The design and component changes include cell type (from monocrystalline silicon [mono-Si] to polycrystalline silicon [poly-Si] and mono-Si along with various thin-film technologies), superstrate (from silicone to glass), encapsulant (from silicone to ethylene vinyl acetate [EVA]), substrate (from fiberglass board to polymeric backsheet), cell string (from one to multiple), interconnect between cells (from one to multiple), and bypass diode (from none to multiple). An excellent representation of design evolution between 1975 and 1984 is shown in Figure 10 (Ross, 2012).

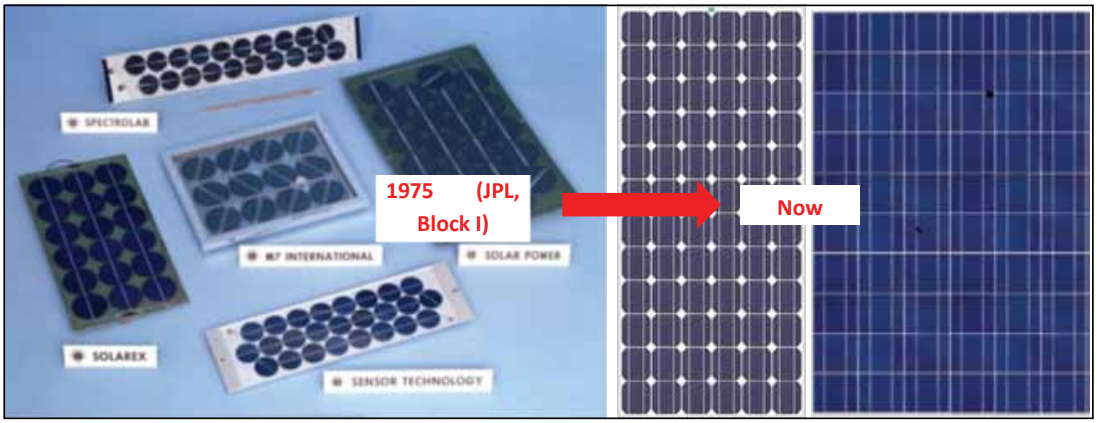


Figure 9: Evolution of PV module design since mid-1970s (Ross, 2012).

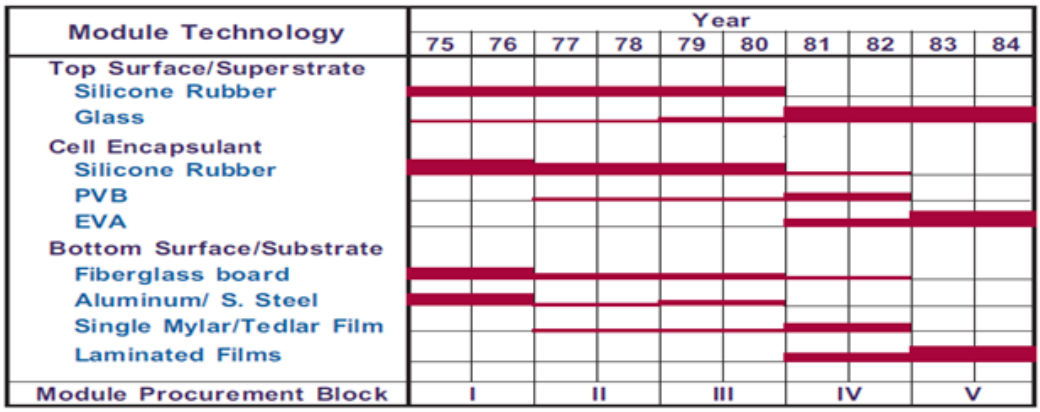
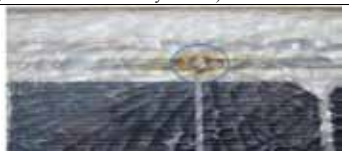
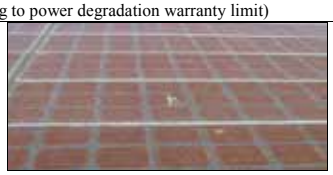


Figure 10: Evolution of PV module construction since 1975 (Ross, 2012).

The failure or degradation modes in PV modules indicate symptoms, whereas failure or degradation mechanisms represent the course for arriving at these symptoms. The field failures and degradation losses may be classified as reliability failures and durability losses, respectively. An extensive list of graphic and photographic representations and examples of field failure and degradation modes are not provided in this report, but can be obtained from the tutorials of various IEEE Photovoltaic Specialists Conferences. The typical field failure and degradation modes of crystalline-silicon PV modules in the field are shown in Table 2. The authors generated this classification table primarily based on information from tutorial material presented at the 2011 IEEE Photovoltaic Specialists Conference (Wohlgemuth, 2011). As stated earlier, the lifetime of PV modules is typically dictated by the degradation rates rather than failure rates, although the failure modes and rates could significantly influence the degradation rates of the PV modules.

Table 2

Failures and Degradation Modes of PV Modules

Failure Modes (Leading to immediate warranty returns)	**Degradation Modes** (Leading to power degradation warranty limit)
	
• Broken interconnects (leading to arcing, backskin burns, or glass shattering or power loss higher than warranty limit) • Solder bond failure (leading to backskin burns or glass shattering) • Severe corrosion (leading to backskin burns or power loss higher than warranty limit) • Chipped cells (leading to hotspots or power loss higher than warranty level) • Encapsulant delamination (leading to power loss higher than warranty level) • Broken glass (leading to safety issue) • Hotspots (leading to backskin burning and safety issue or power loss higher than warranty limit) • Ground faults (leading to safety issue or power loss higher than warranty limit) • Junction box failures (arcing or ground faults) • Connector failures (leading to safety issue) • Structural failures (leading to safety issue) • Bypass diode failures (leading to safety issue due to hot spot or power loss higher than warranty limit due to string loss)	• Gradual cracking of interconnects (leading to power degradation) • Gradual solder bond failure (leading to power degradation) • Slow corrosion (leading to metallization discoloration and power degradation) • Gradual cracking of cells (leading to power degradation) • Gradual encapsulant discoloration (leading to power degradation) • Gradual (photo)electrochemical degradation of semiconducting and/or metallic materials (potential induced degradation leading to power degradation) • Gradual backsheet warping (leading to power degradation) • Gradual increase of module mismatch (leading to power degradation) • Strongly adhering and gradual hardening of soil layer on superstrate (leading to slow cumulative/permanent increase in annual power degradation) or weakly adhering and rain/wind cleaning of soil layer (leading to fixed/temporary annual degradation due to non-cumulative reversible annual rain effect)

Summary—Field Failure and Degradation Modes: Based on the review of an extensive list of field failure and degradation modes, design/packaging/construction and the field environment in which they operate dictate the failure and degradation modes and mechanisms of PV modules.

Field Failure and Degradation Modes, Mechanisms, Causes, and Effects

A failure mechanism is responsible for one or more failure modes. A failure mechanism could be triggered by one or more failure causes and a failure mode could trigger one or more failure effects. The field failure analysis approach for PV modules may be represented as shown in the following sequence:

Failure Mechanism (Cause) ⟶ Failure Mode (Effect)

Example:

Thermo-mechanical fatigue (Expansions-Contractions) ⟶ Broken interconnects (Arcing)

As shown in Table 3, a single failure mechanism may be triggered by one or more failure causes leading to one or more failure modes with each failure mode leading to one or more failure effects. Some failure modes are caused by compound mechanisms instead of just a single mechanism. In the fault tree analysis, all the causes for every failure mode are systematically identified. This table can be used as a tool for troubleshooting through fault tree analysis.

For details on the failure and degradation modes and mechanisms, see Wohlgemuth's tutorial materials from the 2011 IEEE Photovoltaic Specialists Conference (Wohlgemuth, 2011).

Table 3

Field Failure and Degradation Modes and Mechanisms Along With Cause and Effect on PV Modules

Cautionary Note: To differentiate the reliability issues from the durability issues, this table is broken up into two sections—Failure Modes (reliability issues) and Degradation Modes (durability issues). Most of the degradation modes (presented in the second part of the table) can lead to failure modes (presented in the first part of the table) if they go far enough. In other words, most of the failure modes are also caused by the slow degradation modes, which could later become severe, leading to failure modes. For example, one broken interconnect on a cell that has two interconnects in a three-string module will reduce power due to degradation mode but not result in a failure mode as it is still within the warranty limit. However, when both the interconnect ribbons on a cell are broken, the diode will turn on and the module will lose ~ 1/3 of its power, leading to failure as the power drop in the module exceeds the warranty limit. Therefore, the difference between failure mode and degradation mode should be fully understood before assigning a specific field issue under failure mode or degradation mode category.

Field Failure Modes and Mechanisms

Failure Mode	Failure Cause	Failure Effect	Failure Mechanism
Broken interconnects	• Thermal expansion and contraction of interconnects* • Flexing due to wind load or snow load* • Difference in thermal expansion coefficient as compared to substrate/superstrate** • Larger cells** • Thicker ribbon** • Kinks in ribbon** • No stress relief in ribbon**	• Arcing (due to short distance between the broken ribbons) • Backskin burns (due to joule heated hotspots) • Ground fault due to backskin burns (due to water access) • Power drop beyond warranty limit due to severe series resistance or diode activation	• Thermo-mechanical fatigue
Solder bond failure	• Thermal expansion and contraction* • Metal segregation* • Flexing due to wind load* • Vibration during shipment (poor packaging)* • Electrical cycle (day/night or sunny/cloudy)* • Fewer solder bonds per cell (per tabbing ribbon)** • Absence of redundancy for non-cell solder bonds** • No stress relief for interconnects** • Use of non-softer ribbon** • Poor quality of solder bonds (alloy/process)**	• Backskin burns (due to joule heated hotspots) • Ground fault due to backskin burns (due to water access) • Shattered glass (due to hotspots) • Power drop beyond warranty limit due to severe series resistance	• Thermo-mechanical fatigue

Corrosion	• Moisture ingress through backsheet or laminate edges* • Presence of higher ambient temperature along with humidity* • High system voltage due to sunlight presence* • Higher ionic conductivity of encapsulant due to moisture** • Higher moisture absorption of encapsulant** • Metallization (alloy) sensitivity to moisture** • Interconnect (alloy)** sensitivity to moisture	• Hotspot induced backskin burns • Hotspot induced broken glass • Power drop beyond warranty limit due to severe series resistance	• Chemical corrosion (metallic and semiconducting components during nighttime), electrochemical corrosion (metallic components during daytime), or photoelctrochemical corrosion (semiconducting components during daytime) between cells or between cell and frame
Broken cells	• Difference in thermal expansion and contraction of cell components* • Vibration during shipment (poor packaging)* • Wind/snow load* • Larger cells** • Thinner cells** • Larger modules** • Cell chipping**	• Drop in power beyond acceptable/warranty limits (due to increase in crack length and chipping away active cell area; it is to be noted that broken cells often only result in a small power loss not a module failure) • Hotspots (due to reverse bias heating)	• Thermo-mechanical fatigue
Encapsulant delamination	• Sensitivity of adhesive bonds to ultraviolet (UV) light at higher temperatures or to humidity in the field* • Poor adhesive bonds at the interfaces during processing (glass/encapsulant; cell/encapsulant; backsheet/encapsulant)** • Contamination from the material (Excess Na in glass or acetic acid from encapsulant)**	• Moisture ingress • Enhanced encapsulant conductivity and interface conductivity (enhanced chemical/ electrochemical/ photoelectrochemical corrosion) • Major transmission loss • Power drop beyond warranty limit due to optical decoupling and moisture ingress induced corrosion	• Photothermal reaction (interface bonds breakage due to UV and temperature) • Chemical reaction (interface bond breakage because of humidity or contaminants)

Broken glass	• Primary cause may probably be attributed to flying pebbles from cutting the grass • Hotspots or arcs due to broken interconnects or solder bonds because of thermal expansion / contraction* • Thermal gradient within glass (for annealed glass)* • Vandalism (rock throwing)** • Failure of support structure** • Misuse of support structure** • Not following manufacturer's mounting instruction** • Process induced stress (only annealed glass)** • Defective supply chain **	• Ground fault • Enhanced corrosion due to moisture access during rainy and humid days • Dramatic drop in power during rainy days (short circuiting)	• Thermo-mechanical fatigue
Hotspots	• Thermal expansion/contraction of interconnects or solder bonds* • Shadowing** • Faulty cell or cells in a string** • Low shunt resistance cells** • Failure of bypass diode**	• Backskin burns • Decrease in power • Shattered glass • Encapsulant bubbling (localized) • Encapsulant discoloration (localized) • Power drop beyond warranty limit	• Thermo-mechanical fatigue or purely electrical
Junction box failures	• Thermal expansion/contraction of junction box circuit* • Thermal expansion/contraction of junction box attachment/adhesive* • Water access to the junction box circuit beneath the junction box due to poor attachment with backskin (workmanship issue)** • Junction box without proper pottant or drainage** • Water access to the junction box circuit through breathable hole**	• Arcing (inside junction box) • Ground fault • Corrosion • Power drop beyond warranty limit due to severe increase in series resistance	• Thermo-mechanical fatigue

Ground fault	• Installation error (sharp metallic penetration from mounting structure to active cell circuit)**	• Arcing with potential fire	• Not applicable
Backsheet warping/detaching/ cracking/crumbling	• Poor adhesion between encapsulant and backsheet • Moisture ingress through backsheet and/or laminate edges • Polymer disintegration over time	• Ground fault under wet conditions (due to water access to active circuit and frame; however, note that the backsheet issues do not usually result in module failure)	• Chemical reaction weakening interface bonds (due to higher ambient temperature and/or humidity)
Connector failures	• Thermal expansion and contraction* • UV/heat/humidity* • Installation error** • Incompatible male/female parts**	• Arcing • High voltage exposure risk (worse in flat roof puddles!) • Contact resistance energy loss • Connector lifetime reduction (due to higher operating temperature; worse in hot-sunny location rooftops)	• Thermo-mechanical fatigue • Chemical corrosion
Structural failures	• Wind load* • Snow load* • Not following manufacturer's mounting instruction** • Inappropriate frame adhesive** • Inappropriate frame profile** • Inappropriate mounting locations on the frame** • Inadequate installer training** • Insufficient glass thickness**	• Module breakage • Frame deformation	• Mechanical fatigue

Bypass diode failures	• Thermal expansion and contraction* • Insufficient diode rating** • Insufficient heat dissipation inside junction box**	• Open circuit failure of the bypass diode may not result in any noticeable change in module output • Without a functional bypass diode the module will be susceptible to hot spot problems and arcing if an open circuit occurs within the circuit protected by that bypass diode • Short circuit failure of the bypass diode will lead to a loss of the power (beyond warranty limit) produced by the cells being protected by the failed diode.	• Thermal fatigue

Degradation Modes and Mechanisms

Degradation Mode	Degradation Cause	Degradation Effect	Degradation Mechanism
Gradual cracking of interconnects	• Thermal expansion and contraction of interconnects* • Flexing due to wind load or snow load* • Difference in thermal expansion coefficient as compared to substrate** • Larger cells** • Thicker ribbon** • Kinks in ribbon** • No stress relief in ribbon**	• Slow decrease in power (due to increase in series resistance) but within warranty limit	• Thermo-mechanical fatigue
Slow corrosion	• Moisture ingress through backsheet or laminate edges* • Presence of higher ambient temperature along with humidity* • High system voltage due to sunlight presence* • Higher ionic conductivity of encapsulant due to moisture** • Higher moisture absorption of encapsulant** • Metallization (alloy) sensitivity to moisture** • Interconnect (alloy)** sensitivity to moisture	• Increase in series resistance and decrease in power but within warranty limit	• Chemical corrosion (metallic and semiconducting components during nighttime), electrochemical corrosion (metallic components during daytime), or photoelctrochemical corrosion (semiconducting components during daytime) between cells or between cell and frame

Gradual cell breaking	• Difference in thermal expansion and contraction of cell components as compared to superstrate/substrate* • Vibration during shipment (poor packaging)* • Wind/snow load* • Larger cells** • Thinner cells** • Larger modules** • Cell chipping**	• Slow decrease in power (due to decrease in shunt resistance) but within warranty limit	• Thermo-mechanical fatigue
Gradual encapsulant discoloration	• UV exposure at higher operating temperatures* • Reduced breathability** • Higher UV concentration* • Inappropriate additives in EVA**	• Transmission loss • Reduced current/power but may not be affecting fill factor or warranty limit • Cosmetic/visual change	• Photothermal reaction (in the presence of UV and higher module temperature)
Gradual electrochemical corrosion or cation migration to the semiconductor surface/junction	• Moisture ingress through backsheet or laminate edges** • Higher ionic conductivity of encapsulant due to moisture** • Higher moisture absorption of encapsulant** • Metallization (alloy) sensitivity to moisture** • Interconnect (alloy) sensitivity to moisture**	• Series resistance increase and/or shunt resistance decrease depending on bias polarity and climatic conditions • Potential induced degradation leading to power loss but within warranty limit	• Electrochemical corrosion (metallic components during daytime) or photoelctrochemical corrosion (semiconducting components during daytime are more sensitive to electrochemical reactions under light) between cells or between cell and frame
Gradual solder bond failures	• Thermal expansion and contraction* • Flexing due to wind load** • Vibration during shipment (poor packaging)** • Electrical cycle (day/night or sunny/cloudy)* • Small number of solder bonds per cell (per tabbing ribbon)** • Absence of redundancy for non-cell solder bonds** • No stress relief for interconnects** • Use of non-softer ribbon** • Poor quality of solder bonds (alloy/process)**	• Bussbar discoloration • Power decrease within warranty limit due to series resistance increase	• Thermo-mechanical fatigue

Gradual backsheet warping/detaching/ cracking/crumbling	• Poor adhesion between encapsulant and backsheet** • Moisture ingress through backsheet and/or laminate edges** • Polymer disintegration over time**	• Slow power degradation (due to corrosion of cell and circuit components) but within warranty limit	• Chemical reaction weakening interface bonds (due to higher ambient temperature and/or humidity)
Gradual module mismatch	• Difference in degradation rate between field-aged modules in a string caused by poor production quality control**	• Slow power loss at the string/array level (due to operation away from each module's maximum power point) but within warranty limit	• Not applicable
Gradual soiling	• Low tilt angle of modules in soiling-prone locations with infrequent rainfall*	• Slow transmission loss • Reduced current/power but may not be affecting fill factor or warranty limit • Cosmetic/visual change	• Strongly adhering and gradual hardening of soil layer on superstrate or weakly adhering and rain/wind cleaning of soil layer (leading to fixed/temporary annual degradation due to non-cumulative reversible annual rain effect)

Notes: * Environmental Cause ** Material/Design/Process/Construction Cause

A detailed visual inspection checklist, developed by the National Renewable Energy Laboratory (NREL) for recording field failures is presented in Appendix A. For the purposes of statistical and physical modeling of the power plants, these field issues may be segregated into two categories—Module Failures and Module Degradation—as indicated in Table 3.

Summary—Field Failure and Degradation Modes, Mechanisms, Causes, and Effects: Based on an extensive analysis of the individual failure and degradation modes, mechanisms, causes, and effects, failure mechanism could be triggered by one or more failure causes and a failure mode could trigger one or more failure effects.

PV ACCELERATED TESTING: STRESS TYPES, LEVELS, AND PRIORITIZATION

Concept of Accelerated Testing for Photovoltaic Modules

The life characteristics of a product including time-to-failure (TTF) are traditionally obtained using actual degradation field data. In the case of PV modules, the end of life (for example, time-to-degrade 20 % from rated power) may be estimated using a simple linear extrapolation based on the annual field degradation rate (say, 0.8 % P_{max} drop per year). However, the manufacturers and the other stakeholders will have difficulty waiting long enough to obtain the degradation data in the field. The reasons for this difficulty include the very small annual degradation rate and the small time period between design and release. In AT, the product is forced to fail more quickly than it would under use conditions. The sole purpose of an AT program is to obtain life characteristics of the product being tested. In any AT, the general approach is to apply higher stress levels than actual use conditions over a short period of time to induce failures that would normally occur in the field. The AT can be used to induce both hard failures (reliability) and soft losses (durability or degradation).

Highly accelerated life testing (HALT) is a destructive test typically performed in the reliability/design laboratories of manufacturers during product development cycle. The purpose of this test is to find ultimate design weaknesses of the product. Highly accelerated stress screening (HASS) is a non-destructive stress test performed in the manufacturing screens/processes. The purpose of this test is to fail bad products that most likely will fail early in the field and pass good products. Failing units in both tests are subjected to root-cause analysis and corrective action. Both tests are done well beyond use/field levels and the failures are detected in a few months instead of after years/decades in the field. HALT and HASS tests may be performed under step testing mode with one environmental variable at a time (for example, temperature or UV light) or combined testing mode with multiple environmental variables at a time (for example, temperature and humidity). There is no single “standard or universal” procedure for the HALT or HASS test for PV modules, but multiple procedures may potentially be developed for various location/climate specific conditions.

The lifetime of PV modules is a function of a few key major field stresses such as temperature, humidity, UV light, and system voltage. As shown in Figure 11, the acceleration factor is the ratio between time in the field (or use) test and time in the accelerated test. The purpose of accelerated tests for PV modules is to shorten the test time using simulated test conditions much more severe than the actual field operating conditions but without altering actual field failure mechanisms. A conceptual representation of AT of PV modules is shown in Figure 12. The concept basically involves several accelerated stress tests with pre- and post- characterizations. In the AT programs, the stress tests of PV modules are performed at higher levels than the field/use stress levels along with pre- and post-characterization of materials and modules from reliability, durability, and safety perspectives.

Summary—Concept of Accelerated Testing: The concept of and need for AT along with acceleration factor for PV modules are briefly discussed.

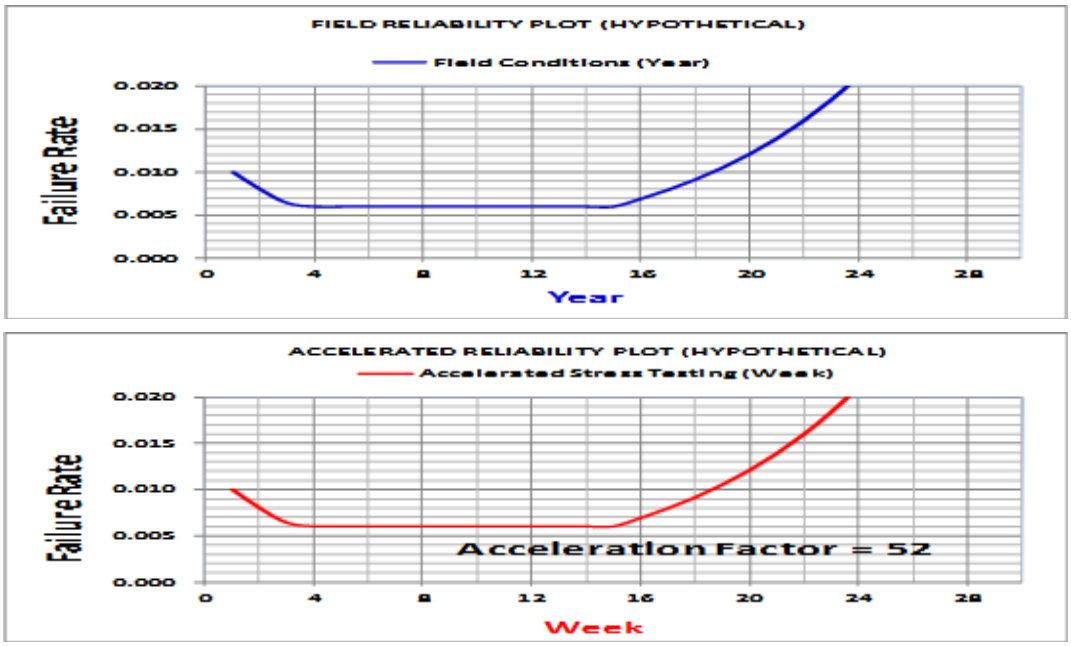


Figure 11: A rudimentary representation of acceleration factor from accelerated testing.

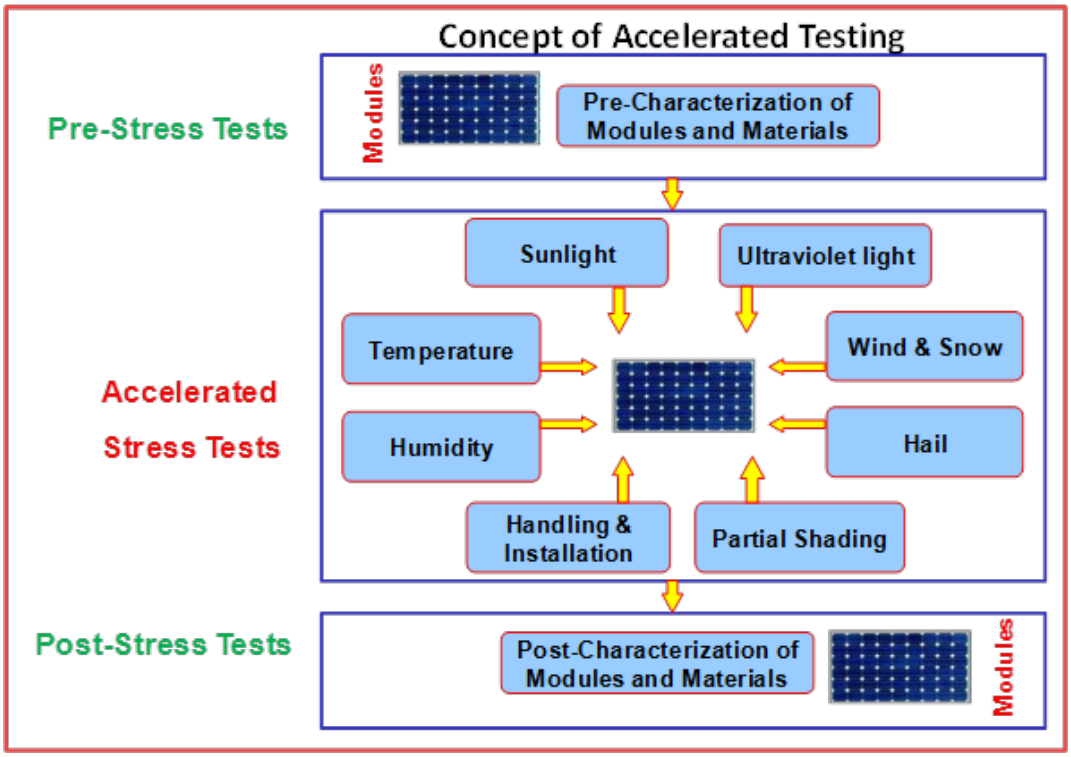


Figure 12: A conceptual representation of accelerated testing of PV modules.

Types and Selection of Accelerated Tests for Photovoltaic Modules

A reliability test can be accelerated in multiple ways. Increasing the level of experimental variables like UV light, temperature, humidity, or voltage can accelerate the chemical processes of certain failure mechanisms such as chemical degradation of adhesive chemical bonds (resulting in eventual weakening and failure) or of additives in the polymeric matrix (leading to discoloration). Variables like voltage and temperature cycling can both increase the rate of an electrochemical reaction (thus accelerating the aging rate). In such situations, when the effect of an accelerating variable is complicated, there may not be enough physical knowledge to provide an adequate physical model for acceleration (and extrapolation). Empirical models may or may not be useful for extrapolation to use conditions. The selected accelerated test programs must use one or more stresses simultaneously and/or sequentially to accelerate failure modes that actually occur in the real world. Module failure modes and lifetime in Miami, Florida, may be very different than in Phoenix, Arizona. One must decide which parameter(s) should be measured to best monitor the failure mode being evaluated and then define what constitutes a failure for that parameter (McMahon, 2004). The typical accelerated tests used to induce various failure modes of PV modules are listed in Table 4 (Wohlgemuth & Kurtz, 2011).

A study performed by BP Solar (Wohlgemuth, 2003) provides a good model for selecting appropriate accelerated tests and their limits specific to PV modules. In this study, BP Solar analyzed all the modules that were returned from the field from 1994-2002. During this time, nearly two million modules were in the field under warranty. The total number of returns during this nine-year period was 0.13%. About 45% of the modules were returned because of corrosion and about 41% were returned because of cell or interconnect breakage. BP Solar determined that the causes for failures were moisture ingress and thermal expansion/contraction, respectively.

Based on these field failure modes, BP Solar designed its AT program to perform thermal cycling in excess of the standard 200 cycles (IEC 61215) and the damp heat (DH) exposure in excess of the standard 1,000 hours (IEC 61215). There should be a standardized or defined approach to select appropriate accelerated tests. For example, the selection of appropriate accelerated tests may be obtained using a 11-step reliability testing program shown in Table 5.

Table 4

Selection of Appropriate Accelerated Tests to Induce Specific Field Failure Modes (Wohlgemuth & Kurtz, 2011)

Accelerated Stress	Failure Mode
Thermal Cycle	Broken interconnect
	Broken cell
	Solder bond failures
	Junction box adhesion
	Module connection open circuits
	Open circuits leading to arcing
Damp Heat Exposure	Corrosion
	Delamination of encapsulant
	Encapsulant loss of adhesion & elasticity
	Junction box adhesion
	Electrochemical corrosion of TCO
	Inadequate edge deletion
Humidity Freeze	Delamination of encapsulant
	Junction box adhesion
	Inadequate edge deletion
UV Test	Delamination of encapsulant
	Encapsulant loss of adhesion & elasticity
	Encapsulant discoloration
	Ground fault due to backsheet degradation
Mechanical Load	Broken interconnect
	Broken cell
	Solder bond failures
	Broken glass
	Structural failures
Dry and Wet Insulation Resistance	Delamination of encapsulant
	Ground faults
	Electrochemical corrosion of TCO
	Inadequate edge deletion
Hot Spot Test	Hot spots
	Shunts at the scribe lines
Hail Test	Broken cells
	Broken glass
Bypass Diode Thermal Test	Bypass diode failures

Note: TCO is transparent conductive oxides

Table 5:

Appropriate Selection of a PV Module Reliability Test Program—An Example With an 11-Step Approach

Task #	Task Type	Element	Example
1	Identify	Field/climate specific failure/degradation mode	Interconnect crack and backskin burning
2	Evaluate	Field failure/degradation effect(s)	Power drop by >20%
3	Identify	Field failure/degradation type	Hard failure
4	Identify	Field failure/degradation cause(s)	Thicker ribbon
5	Understand	Field/climate specific failure/degradation mechanism(s)	Thermo-mechanical fatigue
6	Identify	Appropriate lab accelerated stress test	Thermal cycling
7	Determine	Appropriate lab stress test upper and lower limits	Identification of correct temperature range would be very challenging. As an example, 85°C/-40°C range is used in IEC 61215 qualification standard but it may not be a correct range for the accelerated replication of a specific climatic condition.

8	Determine	Lab stress duration or cycles with ramp rate and dwell time	Identification of right cycle number is also challenging. As an example, 200 thermal cycles are used in IEC 61215 qualification standard but it is certainly not enough for almost all the sites if one is looking at a 25 year lifetime.
9	Identify	Lab failure mode	Power drop by <20%
10	Understand	Lab failure mechanism	Thermo-mechanical fatigue
11	Repeat tasks 6 through 10	Match the field failure mode and mechanism	Power drop exceeded 20%; stop the test

Summary—List and Selection of Accelerated Tests: An extensive list of accelerated tests corresponding to each failure module of PV modules is presented. For the selection of an appropriate accelerated test to quickly induce the required failure mode without compromising the failure mechanism, a 10-step reliability testing program is presented as an example.

Stress Level and Duration Limits of Accelerated Tests for Photovoltaic Modules

The maximum stress levels or duration used during the accelerated tests should not introduce failure modes that do not occur in the field (commonly called foolish failure modes). In order to determine the maximum stress level and duration during AT, it is necessary to identify the use stress level and failure mechanism in the field. The limits for testing time, cycle, and stress level need to be determined for various stresses including temperature, humidity, UV, and voltage. Because the qualification tests defined in the IEC 61215 and IEC 61646 standards were developed based on failure modes identified in the field, the limits identified in these standards may be used as starting points (Wohlgemuth & Kurtz, 2011). Again, the accelerated test levels should not alter the actual field failure mechanisms. For example, the limits identified in the standard thermal cycling test (85°C/-40°C; 200 cycles) and DH test (85°C/85% relative humidity [RH]; 1,000 hours) may be increased provided the failure modes and failure mechanisms of both field failures and accelerated test failure are identical. A few examples for the appropriate and inappropriate stress and duration limits of the primary accelerated tests (for temperature, humidity, UV, and voltage) are presented below.

Stress Level and Duration Limits: Temperature

The temperature cycling is a major stress test done on PV modules to determine the ability of the module to withstand thermal mismatch, fatigue, and other stresses caused by repeated changes of temperature.

Due to substantial difference in the thermal coefficients of expansion between the silicon wafer and the tinned-copper ribbon, bowing and breaking of the thinner wafers could occur if the ribbons are soldered continuously along the screen-printed bus lines on the silicon wafer or just soldered too close to the edge of the cell on front and back (Dhere, 2005). A joint paper published by Sandia and NREL indicates that the changes in solder-joint geometry caused by thermomechanical fatigue reduce the number of redundant solder-joints leading to increased series resistance and decreased performance (Quintana, King, McMahon, & Osterwald, 2002). The stress level and duration limit related to the temperature stress can be increased three ways: the duration of the thermal cycling test can be increased just by increasing the number of cycles at the standard cycle rate of less than 100°C per hour; the stress frequency during the thermal cycle test can be increased by increasing the cycle rate; the stress limit can be increased by increasing the temperature range.

Low cycle rate: Based on the outdoor exposure via comparison to field data and via modeling of weather data, the two hundred normal/standard thermal cycles (between 85°C and -40°C) that are used in the qualification testing have been equated to 10 to 11 years (Wohlgemuth & Kurtz, 2011). For a lifetime of 20 years, additional thermal cycling is required. If the normal 200 cycles equals 10 years of field exposure, then 500 cycles would represent 25 years, assuming linear dependence of power drop on the number of cycles (Wohlgemuth & Kurtz, 2011). The results obtained in another study, presented in Figure 13 (Herrmann et al., 2010), appear to indicate a linear dependence of power drop with the number of cycles during normal thermal cycling (NTC). If one assumes 20% power drop from the original is the durability/warranty requirement for thermal cycling, all seven but one (Figure 13) have met the warranty requirement up to 800 cycles at a temperature difference of 125°C (from -40°C to 85°C). Therefore, the required number of NTC for the lifetime determination may be calculated assuming linear degradation (for example, 0.5%-2.4% power drop per year) in the field and the linear degradation in the accelerated thermal cycling test and/or using the Coffin-Manson model.

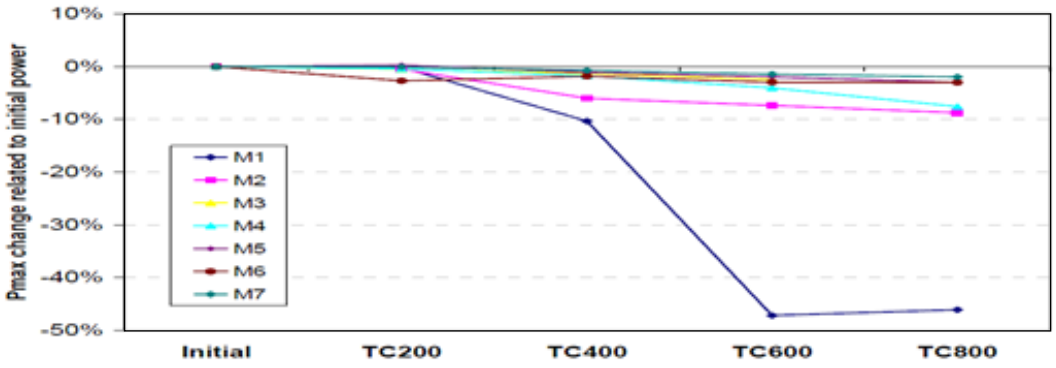


Figure 13: Cycle limit for thermal cycling stress of PV modules (Herrmann et al., 2010).

High cycle rate: A rate of 60°C/hour is commonly used in military specifications and 180°C/hour in space component specification (Hoffman & Ross, 1978). In order to reduce the cycling duration, another research group has attempted to use a rapid thermal cycling (RTC) method with a cycling rate of 400°C/hour (Aoki, Okamoto, Masuda, & Doi, 2010). This study has indicated a power loss of 37% and the failure of solder bonds within 500 cycles as indicated in the impedance study shown in Figure 14. During this 500 cycling period, the testing was paused three times (see Figure 14) and the module was maintained at room temperature, apparently, for the stress relaxation/annealing. Unfortunately, this rapid thermal cycling method has apparently been applied on only one sample with no comparison to the standard/normal cycling method on an identical sample. An extensive NTC study carried out by BP Solar on a specific crystalline silicon module type indicated that the interconnect and solder bond failure from thermal cycling is not likely to be the lifetime limiting failure mechanism for this specific module type (Wohlgemuth, 2008). If the solder bond failure from thermal cycling was not likely to be the lifetime limiting failure mechanism in the field, the failure observed in the RTC method within 500 cycles may be attributed to the thermal shock imposed on the solder bonds (Wohlgemuth & Kurtz, 2011). It may be possible to conclude that RTC at 400°C/hour rate may be a good screening test but it may not be an appropriate lifetime test; however, it may be worth exploring the RTC method with a large number of identical samples comparing NTC (perhaps at various cycling rates of 180, 300, and 400°C per hour cycle rates) and RTC failure modes and mechanisms. This comparative study might determine the upper limit for the cycling rate so the testing time can be significantly reduced.

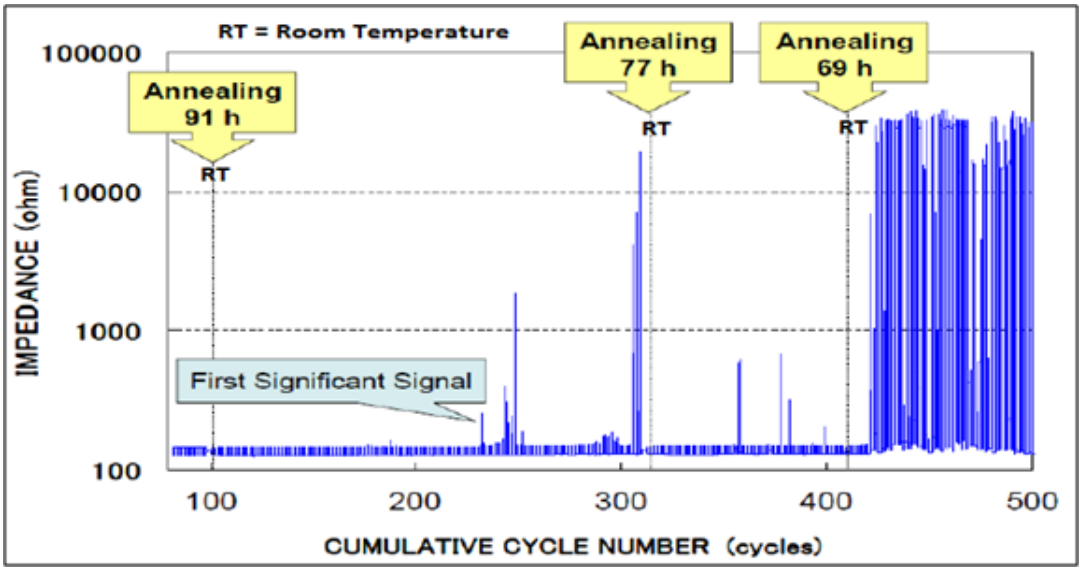


Figure 14: Variation of impedance of during rapid thermal cycling at 400°C/hour rate (Aoki, Okamoto, Masuda, & Doi, 2010).

High temperature range: As shown in Figure 15A, a study performed by SunPower indicates that the solder bond degradation cannot be differentiated between tin/lead (SnPb) and tin/silver (SnAg) if the number of thermal cycles is less than about 500 cycles at standard temperature range of -40°C and 90°C (Meydbray, Wilson, Brambila, Terao, & Daroczi, 2008). This plot also indicates that the SnPb solder bonds experience non-linear degradation with a dramatic increase after about 500 cycles whereas SnAg solder bonds experience linear degradation even up to 2000 cycles. In order to reduce the testing time (or number of cycles), SunPower performed testing on the solder bonds of these alloys at an increased upper

temperature limit of 125°C (high temperature) instead of 90°C and the results are presented in Figure 15B. The required number of cycles for the lifetime determination can be calculated based on the linear and non-linear degradation behaviors of these soldering alloys. However, it is to be noted that, at this upper temperature limit of 125°C, the module encapsulant will be affected leading to other failures that are not seen in the field.

Summary—Temperature Stress Limits: Based on this literature review, the lifetime testing of PV modules for cyclic thermal stress can appropriately be performed just by increasing the number of standard/normal cycles at, perhaps, a higher cycling rate (for example, 200 cycles per hour) and temperature range (for example, -40°C to +90°C) without altering the failure mode and mechanism observed in the standard/normal thermal cycling test (200 cycles from -40°C to +85°C). This literature review indicates that the extended thermal cycling test between 500 and 800 thermal cycles at -40°C to +85°C with less than 100°C/hour ramp rate would be sufficient for the 20-year lifetime prediction of PV modules.

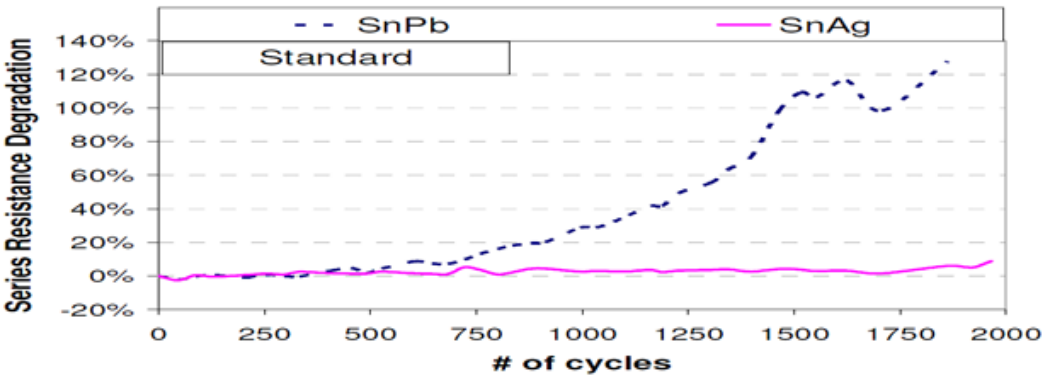


Figure 15A: Performance degradation of PV modules at the cycle temperature of -40°C and 90°C (Meydbray, Wilson, Brambila, Terao, & Daroczi, 2008).

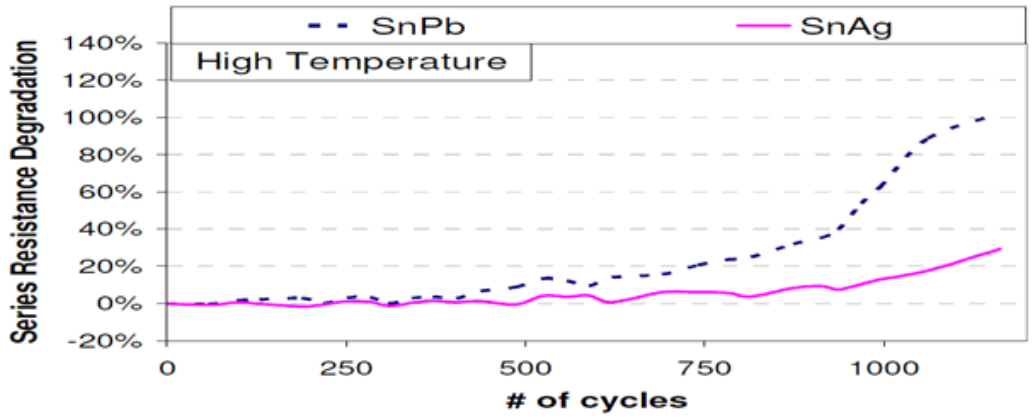


Figure 15B: Performance degradation of PV modules at the cycle temperature of -40°C and 125°C (Meydbray, Wilson, Brambila, Terao, & Daroczi, 2008).

Stress Level and Duration Limits: Humidity

The DH test is another major stress test done on PV modules to determine the ability of the module to withstand the effects of long-term penetration of humidity.

The encapsulant that has been laminated and cured on a flat glass will have reasonable bond strength in a dry environment, but may delaminate when exposed to a humid environment. As shown in Figure 16, the delamination will lead to moisture ingress and subsequent corrosion of cell components. As shown in Figure 21, the same Arco Solar M55 module in a hot-dry climatic condition undergoes encapsulant browning only instead of encapsulant browning and delamination.

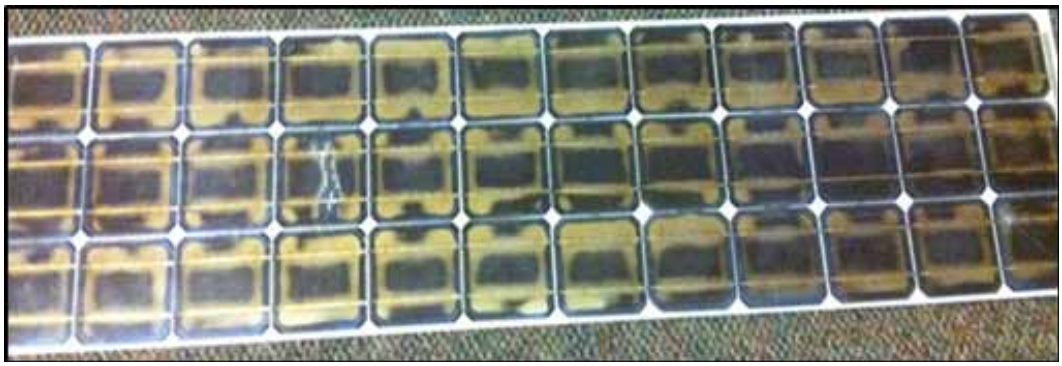


Figure 16: Encapsulant browning, delamination, and moisture ingress induced corrosion of cell components in a hot-humid condition (Site: Austin, Texas; Arco Solar M55 modules installed in approximately 1986 and apparently removed after about 10 years of operation. Photo courtesy: Bill Kaszeta, PVRI).

Currently, the DH testing condition of 85°C/85% RH is extensively used in the qualification standards and by the industry. The hot-humid environment used in this test for 1,000 hours could weaken the interfaces including backsheet/junction box and glass/encapsulant. A recent study indicated that 5.5% (10 out of 183) of the modules that were subjected to this test failed in the post-wet resistance test (TamizhMani et al., 2012). As shown in Figure 17, a detailed diagnostic test revealed that these post-wet resistance failures were due to the weakened interfaces of junction box attachment and laminate edge sealant failure.

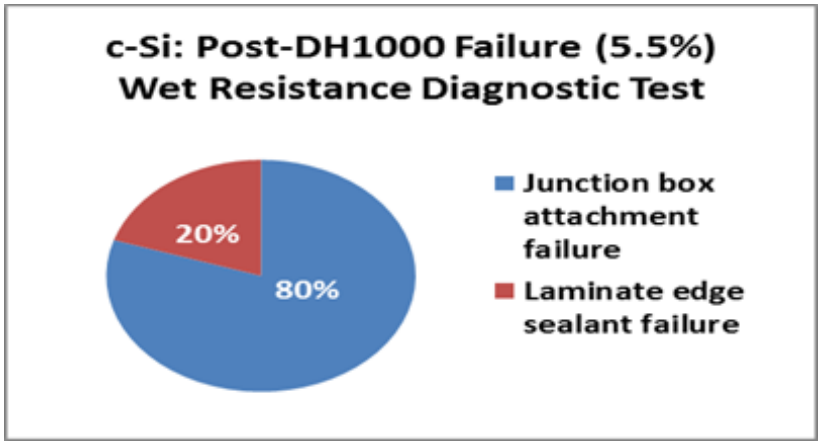


Figure 17: Post-DH diagnostic wet resistance test revealing weak interfaces (TamizhMani et al., 2012).

The stress limit and duration for this test was chosen by JPL in the early 1980s based on a review of nominal module operating conditions in the field and the limitation of the encapsulant material to operate at elevated temperatures. Therefore, a temperature value of 85°C was selected by JPL as a first choice because it was comfortably below the 100°C limit for most encapulant materials but high enough to provide rational test durations of less than six months. The combined 85°C/85 % RH test condition was selected for the module testing because it was commonly used by the semiconductor industry and the cell level reliability research groups.

Module: The effects of high RH on the low temperature (early morning) glass surface of the PV modules could lead to potential induced degradation (discussed in the next section). However, the RH value inside the laminate and at the interfaces within the package is not necessarily the ambient RH and it is expected to be extremely limited inside the package during daytime due to high operating temperatures of the modules and to very limited moisture ingress from the laminate edges or transport through the typical backsheets. In the current accelerated DH testing of IEC 61215, a relative humidity on the glass surface is maintained at 85 % when the cell temperature is at 85°C. This condition never happens in the field and it is difficult to judge what outdoor exposure the 1,000-hour exposure at 85°C/85 % RH represents (Wohlgemuth & Kurtz, 2011).

In order to determine acceleration factors between actual field data and the accelerated test data (for example, 85°C/85 % RH for 1,000 hours), an extensive experimental work based on the recent/current PV module designs and a detailed modeling study needs to be carried out similar to the study published by JPL in 1984 (Otth & Ross, 1983).

The typical meteorological year (TMY) database of United States and other countries provides weather data including hourly RH, irradiance, ambient temperature, and wind speed. Based on the hourly irradiance, ambient temperature, and wind speed, the hourly module temperature can be calculated using JPL, Sandia, or IEC models (Otth & Ross, 1983; IEC68153-2, Draft; King, Boyson, & Kratochvill, 2004). The JPL model (Otth & Ross, 1983) is reproduced below:

$$T_M = T_a + (0.325 - 0.01\ V)\ S \qquad (1)$$

$$RH = (P_d / P_M)\ X\ 100 \qquad (2)$$

Where

T_M = module operating temperature °C

T_a = ambient dry-bulb air temperature °C

T_d = ambient dewpoint temperature °C

V = wind velocity m/s

S = irradiance level mW/cm^2

RH = module relative humidity, %

$P_M = P(T_M)$ = water saturation pressure at temperature T_M

$P_d = P(T_d)$ water saturation pressure at temperature T_d

and where $P(T_d)$ and $P(T_M)$ are evaluated from:

$$\log_{10}[P(T)/218.17] = [B(3.2438 + 0.005868\ B + (0.00227\ B)^3)] / [(T + 273.15)(1 + 0.002188\ B)]$$

Where $B = 374.12 - T$

If the reaction rate with respect to temperature and/or humidity doubles for every 10-unit (10°C or 10 % RH) following a conventional Arrhenius model, then one can calculate the acceleration factor for EVERY hour using JPL models shown below (Otth & Ross, 1983). In these models, 1 % RH is considered to be equivalent to 1 °C as was determined based on an experimental study of one degradation mechanism performed by another research group and referenced by JPL (Desombre, 1980). Based on these models, it is now possible to calculate the equivalent accelerated time required for each TMY/field-hour. Because the equivalent accelerated time for each field-hour is known, one can integrate the equivalent accelerated time for one year or twenty years.

$$t_i = \Delta_i \times 2^{(T_i - 60)/10}$$

and

$$t_i = \Delta_i \times 2^{(T_i + RH_i - 100)/10}$$

Where

Δ_i = duration of field – exposure interval i (1 Hr)

t_i = duration at 60°C , 40 % RH to yield same aging as i

T_i = module temperature during interval i °C.

RH_i = module relative humidity during interval i %

Based on the above models, JPL constructed the plots, shown in Figure 18A and Figure 18B, for Phoenix (hot-dry), Miami (hot-humid), and Boston (cold-dry or temperate) climatic conditions. If temperature is the only aging factor for the PV modules, then the AT at 85°C for 4,000, 8,000, and 10,000 hours is calculated to be equivalent to 20 years of lifetime in Boston, Miami, and Phoenix, respectively (Figure 18A). If combined temperature and humidity are the only aging factors for the PV modules, then the AT at 85°C and 85 % RH for 100, 350, and 700 hours should be equivalent to 20 years of lifetime in Phoenix, Boston, and Miami, respectively (Figure 18B).

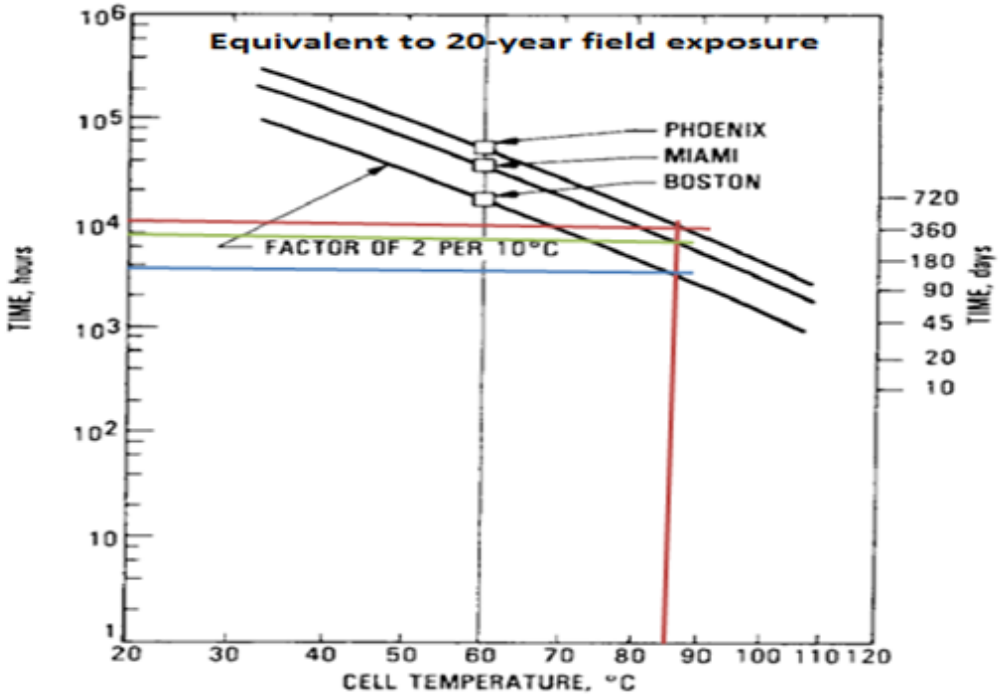


Figure 18A: Accelerated testing at 85°C for 4,000, 8,000, and 10,000 hours is calculated to be equivalent to 20 years of lifetime in Boston, Miami, and Phoenix, respectively.

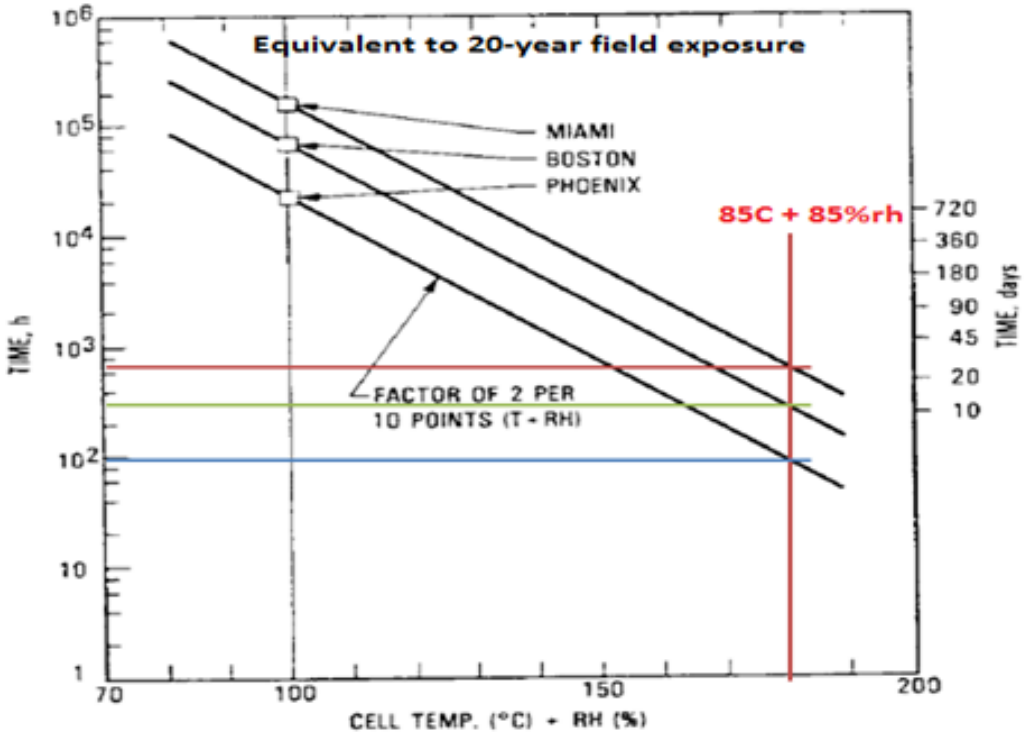


Figure 18B: Accelerated testing at 85°C and 85% RH for 100, 350, and 700 hours should be equivalent to 20 years of lifetime in Phoenix, Boston, and Miami, respectively.

Similar to the thermal cycling test, an approach may be taken to determine the required number of hours for the DH testing. As shown in Figure 19, for conventional screen-printed polycrystalline silicon technologies, it takes about 3,000 hours of DH testing (at 85°C/85% RH) to reach a 20% power loss, the level of degradation typically specified in the 25-year warranty (Wohlgemuth, 2008). However, it is again cautioned that the failure mode seen after 3,000 hours at 85°C/85% RH is not something that is commonly seen in field exposed modules because the modules tend to dry out (both at the surface and in the bulk) in the real world at this high temperature of 85°C. It appears that the 85°C/85% RH test condition uses unrealistic conditions—the 85°C/85% RH test condition appears to be a good screening test (for qualification or comparative testing) but not a good (too severe!) weathering test condition (for lifetime testing). Therefore, there is a need to match the field failure mechanisms and modes in the lifetime accelerated DH testing using a range of temperature and humidity levels. Also, it is yet to be objectively demonstrated that the modules that have experienced less than 20% degradation over 3,000 hours at 85°C/85% RH would have lasted 25 years in the field even if the difference in the failure modes/mechanisms between AT and field testing is ignored.

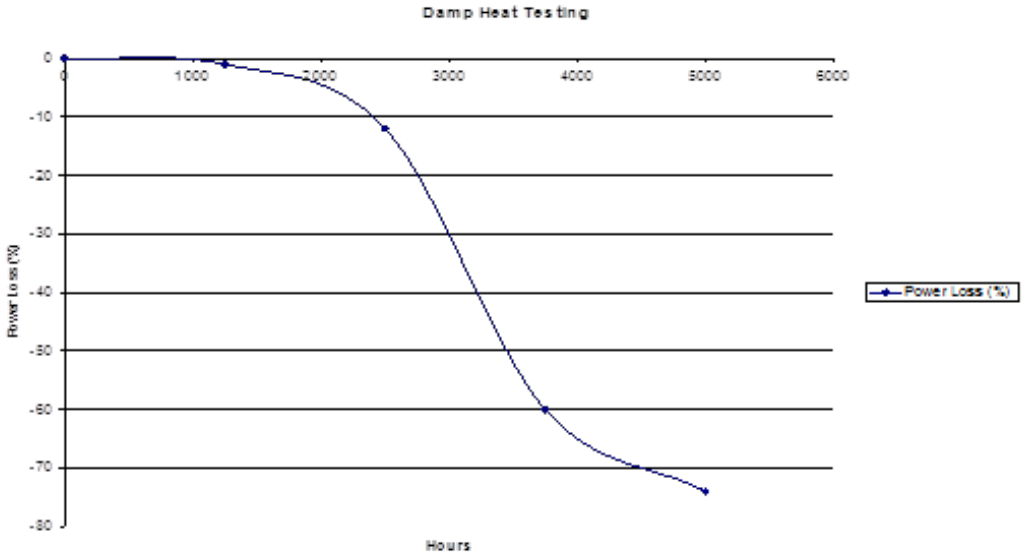


Figure 19: Maximum duration limit for damp heat stress of PV modules.

Backsheets and Encapsulants: The water vapor permeation (moisture ingress) rate through backsheets leads to many failure modes in PV modules and it is related to the change in the molecular weight of the backsheet polymer. For example, the molecular weight of a polyethylene terepthalate (PET) backsheet decreases during hot-humid field exposure through hydrolysis. As shown in Figure 20, a comparison of molecular weight decrease between field aged PET for 15 years at Rokko (Japan) and DH tested PET samples seems to indicate that the standard DH testing at 85°C/85 % RH for 1,000 hours is equivalent to 45 years in the field (Eguchi, 2011). It is important to note that the phase change temperature of polymeric materials should not be exceeded when determining the upper and lower temperature limits for the accelerated tests. Because the 85°C limit used in the DH test is higher than the phase change temperature for PET, the above mentioned linear correlation should be used with caution.

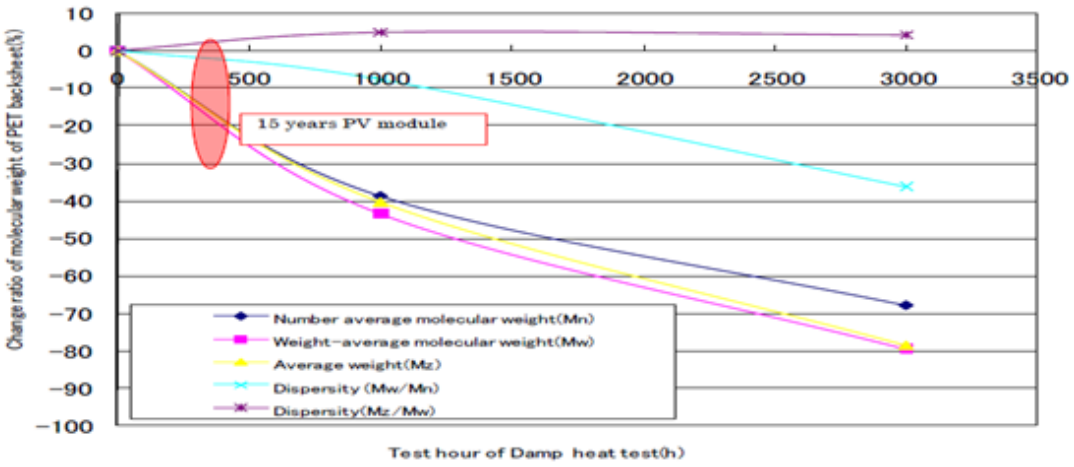


Figure 20: Loss of molecular weight of PET backsheet during extended damp heat test (Eguchi, 2011).

Based on the module operating temperatures at various climatic conditions and the indoor accelerated tests, Fraunhofer Institute ISE research group has calculated the required DH stress time limit for encapsulant and backsheet materials (Kohl, 2009). Depending on the reaction mechanism, the activation energy from one polymer to the other may differ. For example, the activation energies calculated for tedlar-polyester-tedlar (TPT) backsheet and EVA, thermoplastic polyurethane, and polyvinyl butyral encapsulants are 42, 34, 31, and 56 kJ/mole, respectively. This paper indicates that the DH test at the stress limit of 85°C/85 % RH may need to be performed on EVA (activation energy of 34 kJ/mole) for a calculated time of about 1.5 years (13,000 hours) and about 0.5 year (4,000 hours) for a service lifetime of 25 years in tropic and desert climatic conditions, respectively. Similarly, for TPT, the calculated stress time at 85°C/85 % RH stress limit for 25 years' service life in a desert condition is about 1,100 hours. If the activation energy is higher than the ones reported above, then the equivalent testing time at 85°C/85 % RH would be dramatically lower as shown in this plot. It is to be noted that the calculated AT time presented in this work is based on the activation energy only without clearly identifying the corresponding actual field failure modes and mechanisms that are accelerated in the AT. An ongoing study at NREL seems to indicate that the PET layers undergo hydrolysis failure mechanism in the field (Kempe, 2012). Based on the chemical kinetics involved in the hydrolysis process, this work calculates that the 1,000 hours of DH testing at 85°C/85 % RH is equivalent to about 300 years in Bangkok, one of the highest hot-humid climatic condition sites in the world.

Stress Level and Duration Limits: UV

The UV test is another important stress test done on PV modules to identify those materials and adhesive bonds that are susceptible to UV degradation. Typically, the UV absorbers are added in the encapsulant to keep UV from reaching the cell/encapsulant interfaces and the adhesives. Almost all modules contain EVA encapsulant and it does not discolor in UV. There are UV tolerant EVA formulae being sold today without UV absorbers (at least for front EVA). It is to be noted that the encapsulant discoloration occurs not due to the discoloration of EVA or UV absorbing additives but due to the other additives in EVA (anti-oxidants, curing systems, etc. that degrade in UV and cause discoloration) (Holley, Agro, Galica, & Yorgensen, 1996; Shigekuni & Kumano, 1997).

As shown in Figure 21, the discoloration of encapsulant is a common degradation mode due to UV exposure in the field, especially in hot-dry desert climatic conditions. As shown in Figure 16, the same Arco Solar M55 module in a hot-humid climatic condition undergoes encapsulant browning and delamination instead of just encapsulant browning.

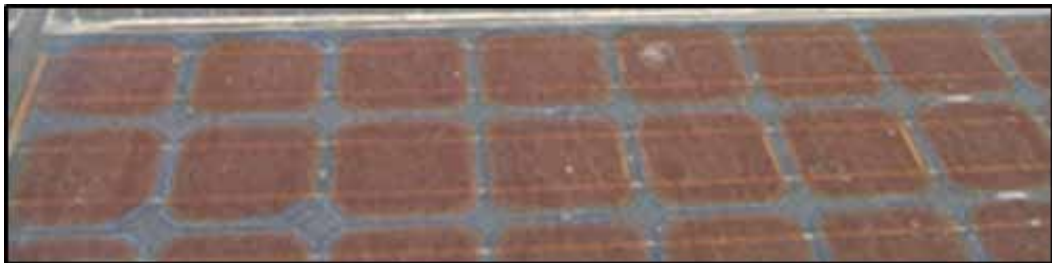


Figure 21: Encapsulant browning due to UV in a hot-dry condition (Site: Phoenix, Arizona; Arco Solar M55 modules installed in 1985 and still operating after 26 + years).

Based on the UV content of about 5.5% of the global irradiance in desert climatic conditions, the total UV-dose in desert conditions is calculated to be about 120 kWh/m^2/year (or about 3,000 kWh/m^2 over 25 years (Kohl, 2011). The UV absorbing additives used in EVA may chemically differ from one EVA manufacturer to the other and hence all EVAs cannot be considered the same. Before initiating the accelerated UV lifetime testing, two important things should be taken into account—selection of the UV source and selection of test sample construction.

The spectra of artificial UV sources strongly differ from the solar UV spectrum. Therefore, different aging behaviors of samples with different UV sources/lamps have to be expected and appropriately accounted for by using appropriate light sources (for example, xenon arc lamps) and correct optical filters. The extent of discoloration of encapsulant is dictated by two competing reactions: discoloration by UV light; bleaching by diffused oxygen through substrate or superstrate (Gonzalez, Liang, & Ross, 1985; Holley, Agro, Galica, & Yorgensen, 1996). Figure 22 clearly differentiates how the UV discoloration reaction dominates at the center of the cells and how the oxygen bleaching reaction (using diffused oxygen through the backsheet) dominates at the cell edges and cell cracks. Because the crystalline silicon (c-Si) wafers/cells do not allow oxygen to diffuse through and the inter-cell area is very limited in the current commercial modules (due to high packing density of square or scrounded cells as compared to round cells), the oxygen bleaching counter reaction of the encapuslant on the cell surfaces (which primarily dictate the power output) is very limited in current commercial modules.

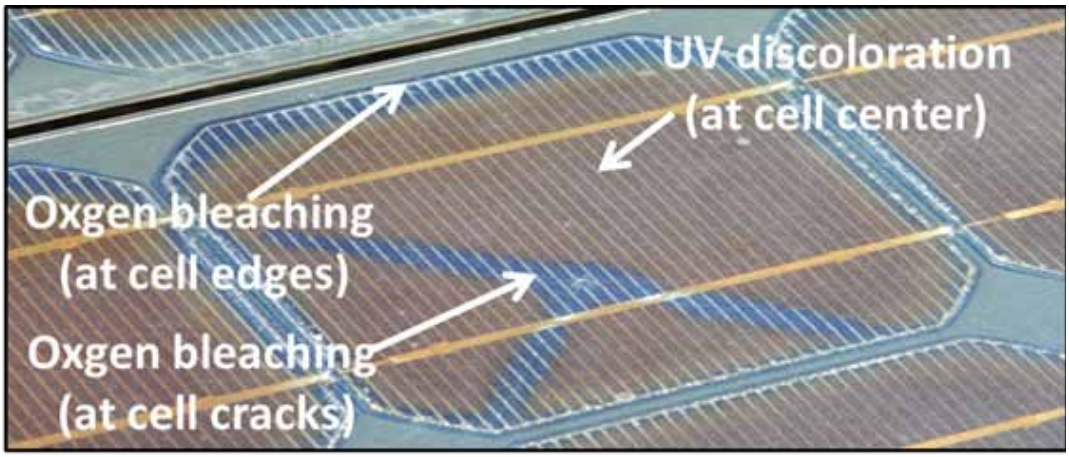
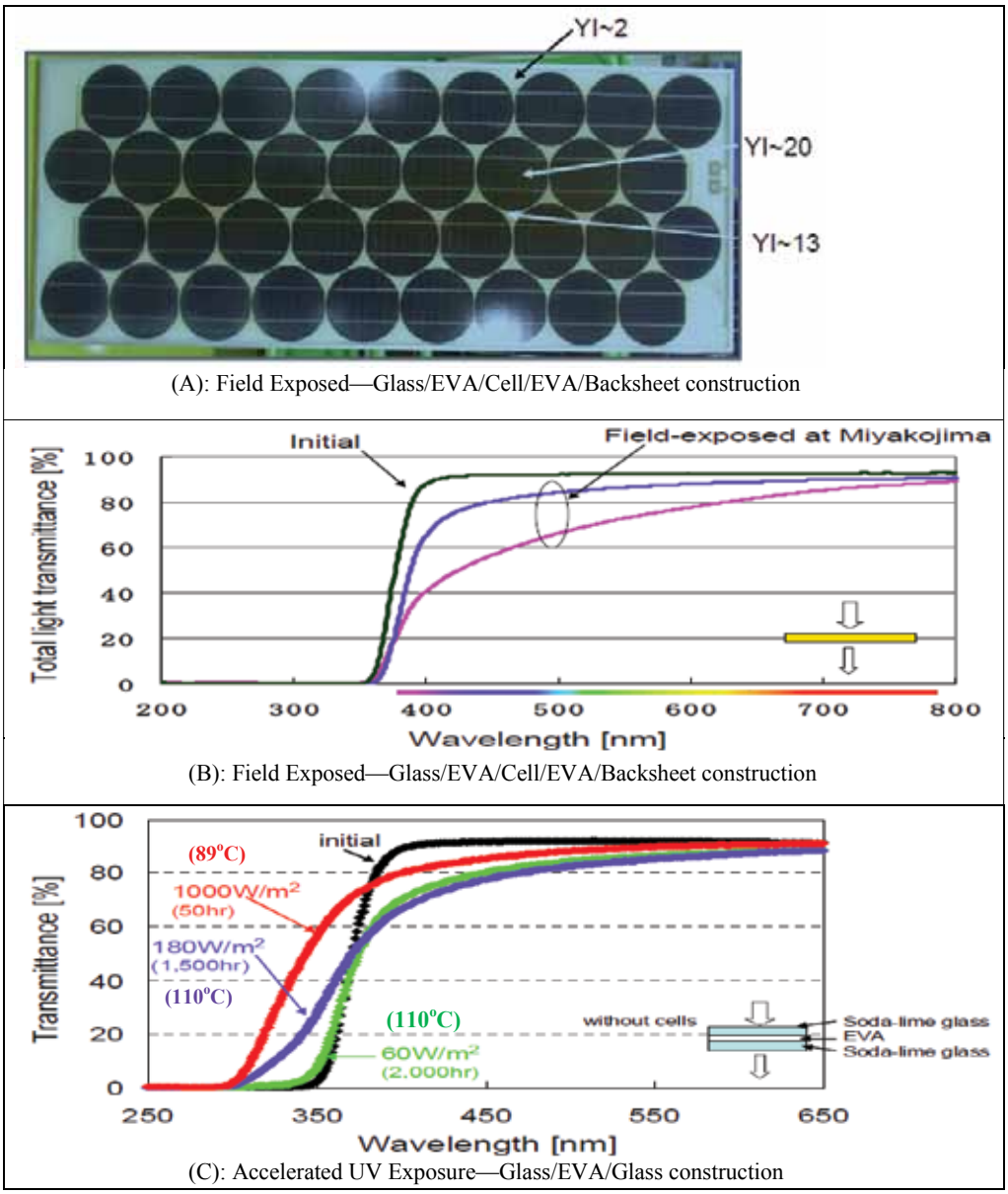


Figure 22: Encapsulant browning due to UV and bleaching around the cells and cell-cracks due to oxygen diffusion through backsheet and cell-cracks in a hot-dry condition (Site: Phoenix, Arizona; Arco Solar M55 modules installed in 1985 and still operating after 26+ years).

Figure 23 provides results of a specific EVA, called EVA-1 (Shioda, 2011). The modules based on EVA-1 were exposed in the field over 20 years and showed little (at the center and cell-gaps) or no (at the edges) activity loss of additives. The construction of these modules appears to be: glass/EVA/Cell/EVA/polymer backsheet with aluminum foil. Freshly constructed samples of the same EVA-1 were tested in the lab at 110°C and 60 W/m^2 UV irradiance (equivalent to UV dosage in natural sunlight) using a construction of glass/EVA/glass. When EVA-1 was tested in the lab at a UV irradiance tripled in intensity compared with that of natural sunlight (180 W/m^2) but at the same temperature of 110°C, the additives appear to have lost part of their activity without simulating the actual field failure mechanism. The temperature dependent EVA discoloration reaction rate without including oxygen

bleaching counter reaction rate and the corresponding acceleration factor may be modeled using the Arrhenius equation (Gonzalez, Liang, & Ross, 1985). In order to evaluate the adhesion strength of EVA due to UV exposure over 20 years, it is necessary to continuously expose the test samples, with high UV transmittance glass in a typical weatherometer (2.5 UV suns at 60°C and 60 % RH) for 6 to 7 months (Kempe, 2008). BP Solar reported the use of a UV-exposure at 90°C for 26 weeks (6.5 months) to verify a 25-year lifetime (Wohlgemuth, Cunningham, Monus, Miller, & Nguyen, 2006). The temperature limit (60-90°C) and the relevance of humidity presence (0-60 % RH) with respect to encapsulant browning and delamination still need to be investigated.

Summary—UV Stress Limits: For the lifetime accelerated UV testing (for 20-25 years), the UV testing should be extended much beyond the qualification testing program. The literature indicates that the testing duration may have to be extended for 6 to 7 months with 2.5 times the UV dosage of natural sunlight. For the lifetime UV test, the temperature limit (60-90°C) and the relevance of humidity presence (0-60 % RH) with respect to encapsulant browning and/or delamination still need to be investigated.



(A): Field Exposed—Glass/EVA/Cell/EVA/Backsheet construction

(B): Field Exposed—Glass/EVA/Cell/EVA/Backsheet construction

(C): Accelerated UV Exposure—Glass/EVA/Glass construction

Figure 23: Acceleration limit for UV stress on glass/EVA/glass sample (Shioda, 2011).

Stress Level and Duration Limits: Humidity-Freeze

The purpose of this test is to determine the ability of the module to withstand the effects of high temperature and humidity followed by sub-zero temperatures. In the humidity-freeze test, the modules are cycled once a day for 10 days between -40°C and 85°C/85% RH. The hot-humid environment (causing absorption of moisture) followed by sub-zero temperature (causing expansion of the absorbed water as it freezes) used in this test detects weakness of the interfaces including backsheet/junction box and glass/encapsulant. A recent study indicated that 8.8% (11 out of 125) of the modules that were subjected to this test failed in the post-wet resistance test (TamizhMani et al., 2012). Similar to the DH test, the post-wet resistance failures were attributed to the weakened interfaces of junction box attachment and laminate edge sealant failure.

The humidity-freeze test was initially developed by JPL and the object of this test was to force moisture into the module and observe mechanical and moisture-induced corrosion via visual inspection. This stress test is usually done for 10 cycles between -40°C and +85°C in a sequence after short UV (15 kWh) and thermal cycling (50 cycles) pre-conditioning stresses. If there is an insufficient cross-linking or adhesion between interfaces (glass/encapsulant, encapsulant/cell, backsheet/encapsulant and junction box/backsheet in c-Si modules, and glass/edge sealant/glass in thin-film modules), this screening test can quickly identify these issues. This test is not considered to be a lifetime test and it does not necessarily need to be extended beyond 10 cycles. This test sequence has proven to be extremely sensitive and important in the qualification testing programs to pre-screen the adhesion strength of junction boxes to the backsheet of c-Si modules and the edge sealants of thin-film modules (the qualification test results of several thousands of modules are discussed in the next section).

Summary—Humidity-Freeze Stress Limits: Based on this literature review, the humidity-freeze test identified in the existing qualification testing would be sufficient to pre-screen the modules for the weak interfaces. Because it is not considered as a lifetime test, this test does not need to be extended beyond the 10 cycles identified in the current qualification standards.

Stress Level and Duration Limits: Voltage

Potential induced degradation (PID) due to high system voltages in hot-humid climates can be a major degradation mechanism in PV modules, and it adversely affects the performance of PV modules due to combined effects of two or more of the following factors: system voltage, superstrate/glass surface conductivity, encapsulant conductivity, and silicon nitride anti-reflection coating property. As shown in Figures 24A and 24B, a module can experience different types and extent of degradation depending on the grounding configuration, polarity, and module position in the string (Pingel et al., 2010).

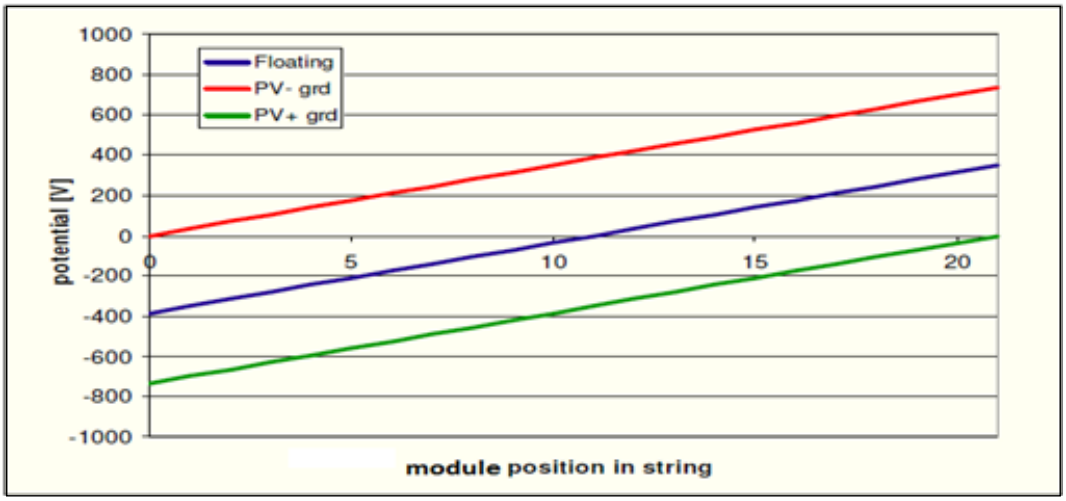


Figure 24A: Floating arrays with both positive and negative polarities and grounded arrays with either negative or positive polarity (Pingel et al., 2010).

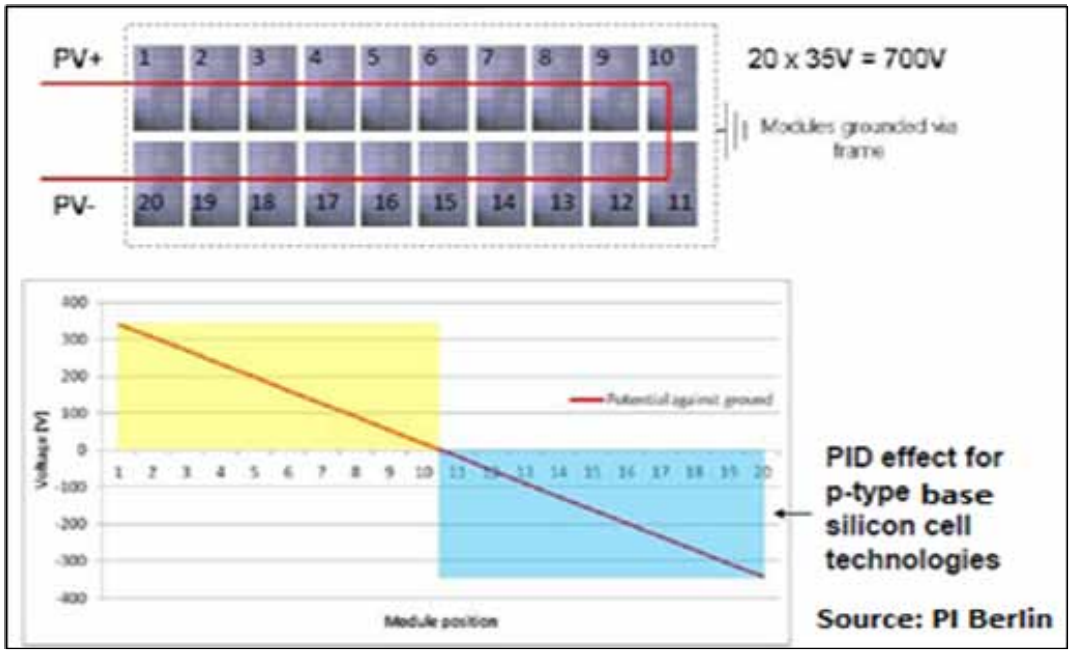


Figure 24B: An example of a floating array with both bias polarities (Pingel et al., 2010).

As shown in the simplified diagram of Figure 25, the high system voltages (600-1500 V) in the PV systems could lead to leakage current between the cell/active circuit and the ground and hence could cause gradual performance degradation depending on the cell bias type and magnitude of leakage current. PID can be increased by increasing applied/system voltage, operating temperature, or electrical conductivity between cell/active circuit and module frame through surface conductivity (for example, condensed water layer on the glass surface), interfacial conductivity (for example, between cell and encapsulant), and/or bulk conductivity (for example, through encapsulant).

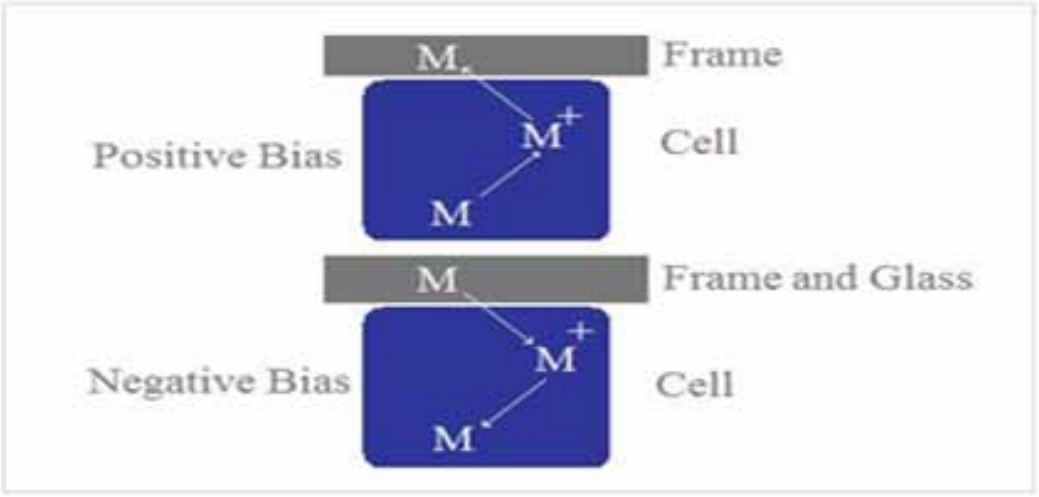


Figure 25: A representation of electrochemical activity between the frame/glass and cell.

The original research on the electrochemical degradation of c-Si and thin-film modules was initiated by JPL in the 1980s (JPL, 1986). A renewed interest in this research, now named PID, was motivated by a few recent field issues related to electrochemical degradation of thin-film and crystalline silicon modules (Dhere, Pethe, & Kaul, 2010; Hacke et al., 2011). Figure 26 indicates that an accelerated factor of 427 for PID can be obtained for the hot-humid use condition in Florida at -600 V by stressing the modules at 60°C and 85% RH for 96 hours (Hacke, 2012). This stress condition is estimated to be equivalent to about 4.7 years of the field use condition of Florida. For a 20-year lifetime, this linearly translates to 400 hours of PID stress testing at 60°C and 85% RH. The higher stress levels at or above 70°C and 70% RH lead to high chemical activity of water that leads to degradation modes such as silicon nitride degradation and series resistance increases that are not seen in the field (Hacke et al., IEEE PVSC 2012). Therefore, it is important to eliminate PID stress conditions of the AT that induce electrochemical activities not seen in the field.

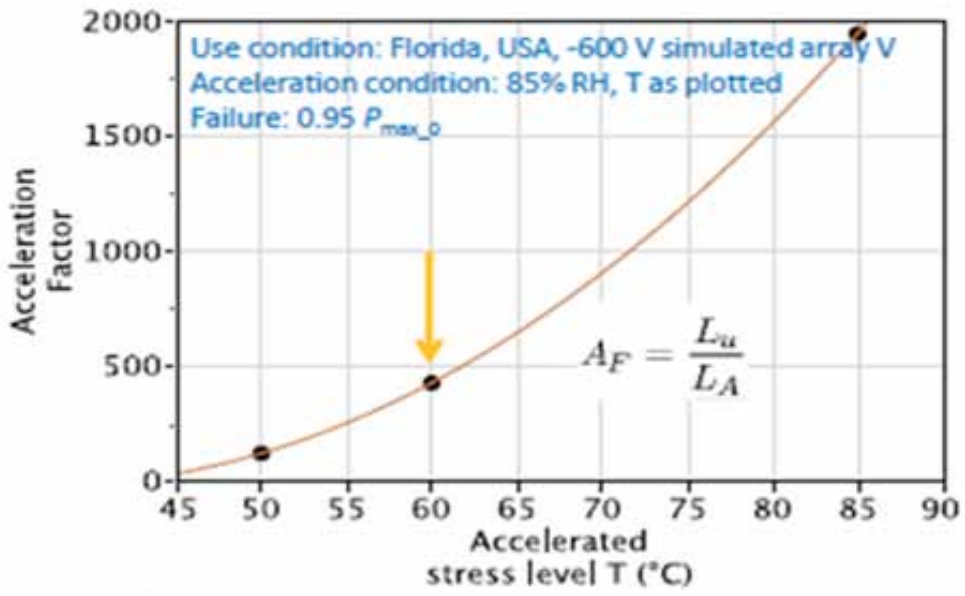


Figure 26: PID acceleration factor dependence on stress temperature level (Hacke, 2012).

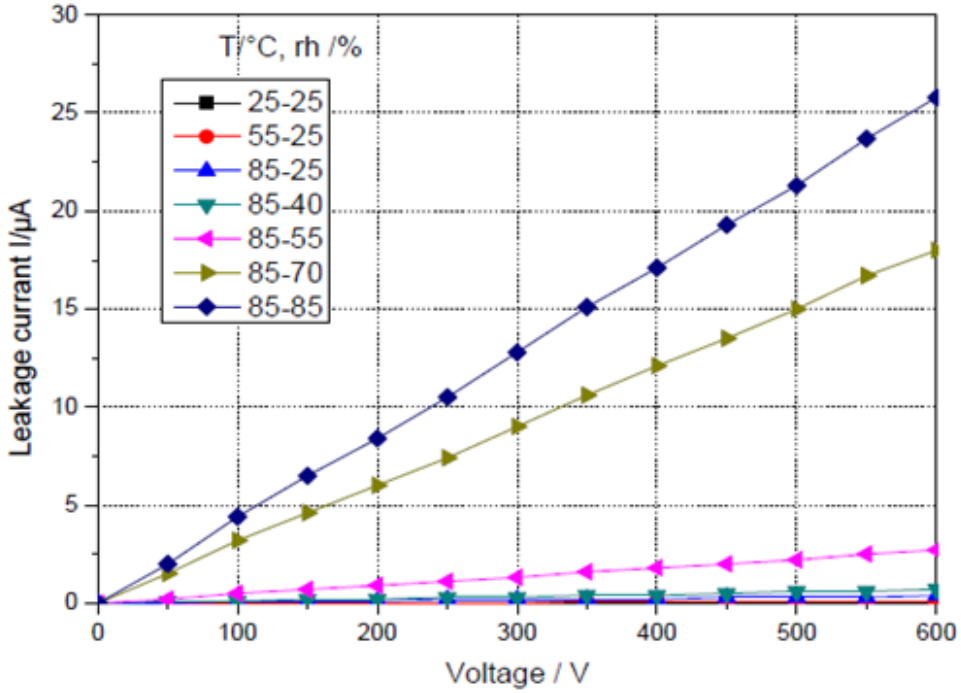
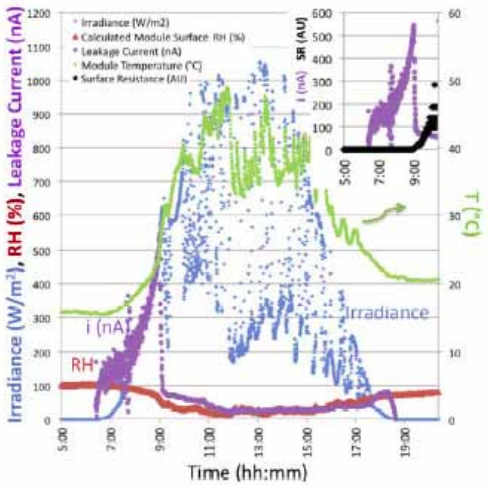


Figure 27: Linear dependence of current on stress voltage, and the combined voltage, temperature, and humidity effects on the leakage current of a module (Hoffmann & Koehl, 2012).

In chemical kinetics, the activation energy (in joules per mole) influences the chemical reaction rate (in moles per second) whereas in electrochemical kinetics the overpotential (in volts) influences the electrochemical reaction rate (in amps). Depending on the overpotential magnitude, either the Butler-Volmer (zero overpotential), Stern-Geary (low overpotential), or Tafel (high overpotential) equation may be applied (Revie, 2000; Greene, 1986). The low overpotential (called polarization overpotential due to polarization resistance, R_{pol}) is composed of activation overpotential (or electrochemical activation energy) and ohmic overpotential. The ohmic overpotential (due to ohmic resistance, R_{ohmic}) in a PV module is caused by the bulk resistance of encapsulant, bulk resistance of glass, surface resistance of glass (primary ohmic drop), and the interface between glass and encapsulant. The activation overpotential (due to activation resistance, Ract) in a PV module is caused by the interface between the electrode (active cell circuit) and electrolyte (encapsulant). The linear plot shown in Figure 27 above appears to be caused by both ohmic overpotential and activation overpotential. Because the ohmic overpotential in a PV module is extremely high as compared to the activation overpotential, the effect of activation overpotential is completely masked. In order to determine the activation overpotential and isolate it from the ohmic overpotential, it may be necessary to use the electrochemical impedance technique.

Figure 28 indicates that the module surface relative humidity is close to zero when the sun is shining in a hot-humid climatic condition (Hacke et al., 2011). During the sunny hot part of the day, the entire voltage is expected to drop on the glass surface with negligibly small voltage drop in the bulk and cell/encapsulant interface, leading to an absence of any PID during the sunny hot part of the day. The field data shown in this figure imply that the degradation may mostly occur first thing in the morning or after a rainstorm when there is high humidity and before the module has time to dry out in the sun. This situation may be simulated in the AT using a conductive carbon layer on the glass surface.



Leakage current to ground, irradiance, calculated module surface relative humidity (RH), and module temperature over a one-day period in Florida. The module is horizontally mounted, the active layer is biased to scale logarithmically with irradiance to a maximum voltage of -600 V with module leads connected to a load resistor to maintain approximately P_{max}. The leakage current is highest when morning dew is on the module face and the surface resistance (SR) is low (inset). When the module is dry, the current most closely follows the calculated module surface RH.

Figure 28: When sun is shining, the module surface relative humidity is close to zero even in a hot-humid climatic condition (Hacke et al., 2011).

Figure 29 shows the results of a simulated experiment with the interruption of surface conductivity using a carbon layer (Tatapudi, 2012). These PID experiments were performed on the thermal cycling (TC) (thermal cycling 200) and DH (DH 85°C/85 % RH) pre-stressed modules rather than fresh modules to simulate the field aged modules going through PID stress. As shown in Figure 29, the ohmic resistance could be increased (or PID eliminated) to a very high level by interrupting the surface conductivity of the glass near the frame edges using either hydrophobic coating, glass surface modification with water repellent properties, or thick edge sealants for the frame attachment. In the high surface conductivity PID test (surface fully carbon coated), the primary ohmic drop occurs in the bulk and interfaces similar to first thing in the morning or after a rainstorm in the field. In the disrupted surface conductivity PID test (surface partially carbon coated), the primary ohmic drop occurs on the glass surface similar to the sunny hot part of the day. This plot also indicates that the pre-DH-stressed modules degrade at much higher level than the pre-TC stressed modules possibly due to increase in the bulk conductivity of the encapsulant because of moisture ingress during the 1,000 hour DH test. It is important to note that no PID effect has been reported on the fresh modules if the cells do not have the silicon nitride antireflection coating. Recent studies on the fresh modules indicate that the PID effect is mostly, if not entirely, reversible if reverse voltage (positive voltage) is applied on c-Si with p-base (Hacke et al., 2011). This probably implies that the irreversible electrochemical reaction involving cell metallization may not occur on the fresh modules during PID stress testing. However, the irreversible electrochemical reaction involving cell metallization may occur if the module had been pre-stressed at 85°C/85 % RH for 1,000 hours (TamizhMani, 2012). This study seems to indicate that both reversible and irreversible degradation mechanisms may be operating on the DH pre-stressed modules. It is not yet clear whether PID involves only the silicon nitride (SiN) layer or both the SiN layer and the cell metallization in the actual field aged modules. This requires further investigations and characterizations of the field aged modules in hot-humid climatic conditions.

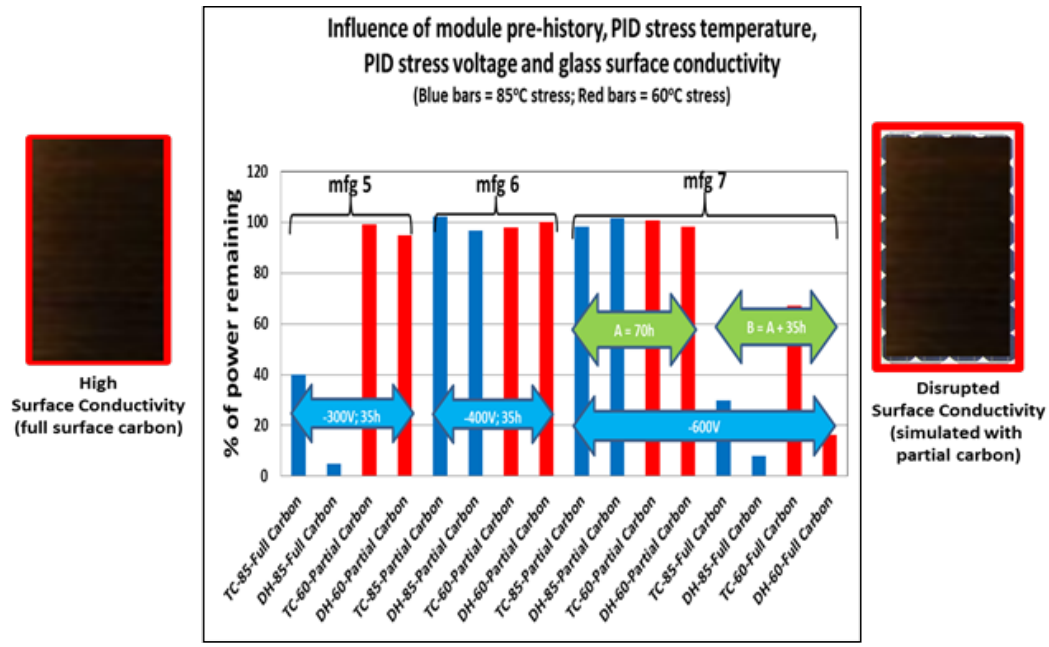


Figure 29: Avoiding PID by disrupting the glass surface conductivity near frame edges (Tatapudi, 2012).

A general model for the leakage current of PID test as a function of temperature, humidity, and voltage is given in the following equation (Hoffmann & Koehl, 2012).

$$I = I_{max}/(1 + (I_{max}/c - 1)/\exp(I_{max} \times (rf - a) \times b))$$

with

$$I_{max} = U/R_a(358\ K)\, A \cdot \exp[-(E_a/R) \cdot (1/T_{test} - 1/358\ K)]$$

The remaining parameters a = 0.3, b = 1.5/mA, and c = 0.3 mA describe the slope of the current increase and the offset of the sigmoidal curve shown in Figure 30.

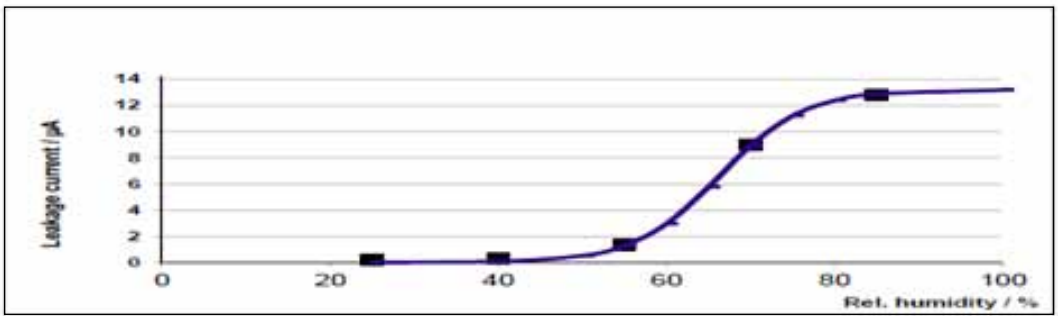


Figure 30: Sigmoidal leakage current dependence on relative humidity.

It is possible that the primary voltage drop location is shifted from the glass surface to the bulk and cell/encapsulant interface when the RH increases to higher than 60 %. The humidity on the glass surface probably forms a continuous water layer and efficiently conducts electricity when the RH exceeds 60 %. Therefore, at higher humidity and lower temperature levels (for example, 60°C/85 % RH), the primary voltage drop occurs in the bulk and cell/encapsulant interface due to low ohmic resistance on the glass surface. At lower humidity and higher temperature levels as in the field (85°C/60 % RH), the primary voltage drop occurs on the glass surface and in the glass and encapulant materials due to high ohmic resistance.

As shown in the voltage drop distribution schematic in Figure 31, the cell/interface reaction in the early morning is accelerated due to high surface humidity level (surface with dew) as compared to the daytime low/zero glass surface humidity. It may be envisioned that the shift in the location of voltage drop from surface (ohmic location) to interface (activation location) under high humidity condition may be identified by using the combination of both Arrhenius and electrochemical impedance plots obtained at different temperature and humidity levels. Because the semiconductor materials behave very differently in the presence of light and humidity in the interface, the PID tests may need to be performed in the presence of light to investigate the presence or absence of photoelectrochemical reaction at the cell/encapsulant interface (Noufi, Frank, & Nozik, 1981; Gerischer, 1977; Wrighton, 1977).

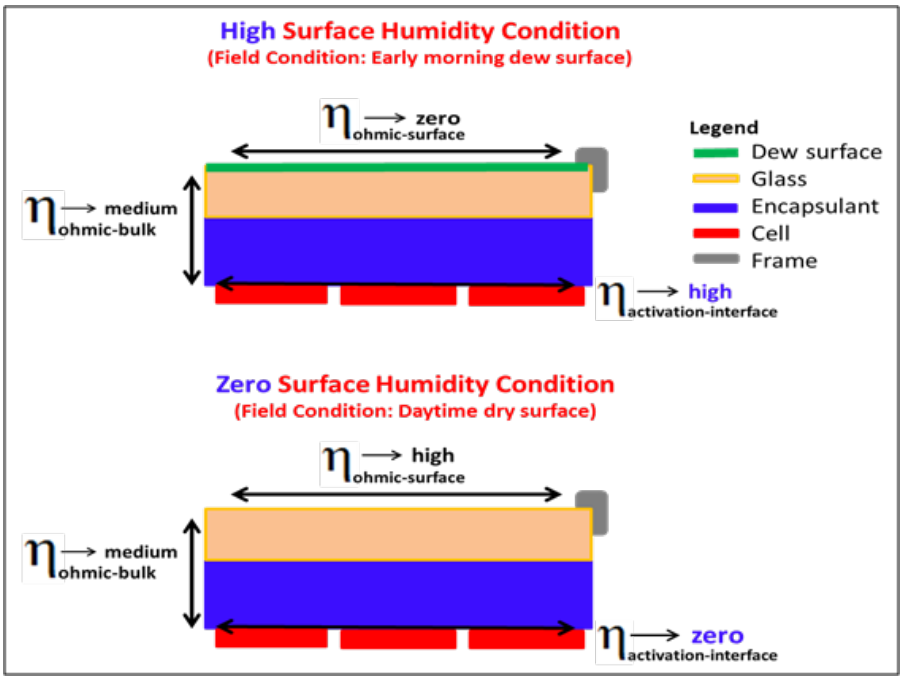


Figure 31: Voltage drop distribution under high and zero/low glass surface humidity levels

Summary—Voltage Stress Limits: Based on this literature review, the leakage current has a linear dependence on the applied voltage and it sharply increases when the RH increases above 60 %. Because the high humidity level on the glass surface is expected in early mornings and after rainstorms on the field operating modules, it may be important to perform the lifetime accelerated PID tests at higher humidity levels (> 60 % RH) for the proportional acceleration of voltage distribution across surface, bulk, and interface. In order to reduce the testing time, it may be necessary to increase the test temperature as high as possible but without compromising the replication of the field failure mechanisms. It has been shown that the PID testing at 85°C/85 % RH is too severe, not replicating the real field issue.

Recent studies appear to indicate that the use of 60°C/85 % RH test condition may be appropriate to replicate the real field issue. It may be possible to further reduce the testing time by increasing the temperature from 60°C to a higher temperature but less than 85°C. It is also recommended that the PID test be done on the post-DH stressed modules rather than on the fresh modules to correlate the results with the actual long-term (15 to 25 years) field data. It is recommended that the future PID investigations (with and without light) include both Arrhenius and electro-chemical impedance studies at different temperature and humidity

levels, especially high humidity levels. Aluminum foil or carbon coated test method may be considered as a good screening technique for the PID susceptibility investigations of the cells but may not be a good durability test technique for the packaged modules as it does not simulate the field reality. The humidity in the field may be present on the glass surface and inside the bulk and interfaces of the encapsulant due to moisture penetration through backsheet and laminate edges whereas the metallic layer on the glass surface does not penetrate to the bulk of encapsulant. Also, there are a few unique module/laminate mounting solutions/means adopted by the industry to avoid or reduce the PID effect, and those modules with unique mounting solutions may not be appropriately tested if the conductive metallic layer (aluminum or carbon) method is used, because it short circuits the mounting means with the glass surface.

Prioritization of Lifetime Accelerated Tests for Photovoltaics

In the previous sub-sections, the selection and level/duration of accelerated tests applicable to PV modules have been identified. In this sub-section, a prioritization of these accelerated tests is discussed. The accelerated tests need to be prioritized from both reliability (failure) and durability (degradation) perspectives. It is to be noted that the lifetime of PV modules may be limited either due to hard failure issues or to degradation issues (degradation beyond warranty limits).

Prioritization From Reliability (Failure) Perspective

The prioritization of accelerated tests may be based on the initial failures in the field or the wear-out failures in the field. The qualification testing deals with the initial failures in the field and the lifetime testing deals with wear-out failures in the field.

The prioritization of lifetime accelerated stress tests needs to be done based on the failure and degradation sensitivity of the technology to a specific set of environmental conditions. The specific set of environmental conditions could be hot-dry, hot-humid, and cold-dry (temperate). There is a great need to develop a database based on the climate-specific technology-sensitive wear-out failures in the old (10 to 30 years) power plants that have similar or identical construction characteristics as that of the current generation modules. Because no such database currently exists based on the wear-out field failures, it is not possible to identify and prioritize the accelerated stress tests relevant to field-specific wear-out failures at this stage of research.

As indicated later in this report, the objective of qualification testing is to identify major failure modes during the initial stage in the field without attempting to make any predictions about the product's life under normal use condition. Because the current qualification testing programs (IEC 61215 and IEC 61646) have been developed based on the recorded initial field failures, the qualification failure databases from different test laboratories could help prioritize the accelerated stress tests, which would allow the manufacturers to successfully pass the qualification testing and to introduce the product in the marketplace. Note that the prioritization of the accelerated tests for the lifetime testing should be based on the field-specific wear-out failures, whereas the prioritization of the accelerated tests for meeting the qualification testing requirements may be based on the qualification testing failure databases of various test laboratories (TamizhMani et al., 2012). As shown in Figure 32A, crystalline silicon technology is sensitive to the following top three accelerated

tests to meet the pass criteria of the IEC 61215 qualification testing standard (based on the testing of 1,111 modules of the most recent 2009-2011 designs): humidity freeze, thermal cycling, and DH. As shown in Figure 32B, these post-stress failures were identified using visual inspection, insulation test, and wet resistance failure criteria at the completion of each accelerated test of the qualification testing programs. (Note that the failure rate in Figure 32A may be lower than the sum of failure rates shown in Figure 32B due to the application of up to three pass criteria for each stress test).

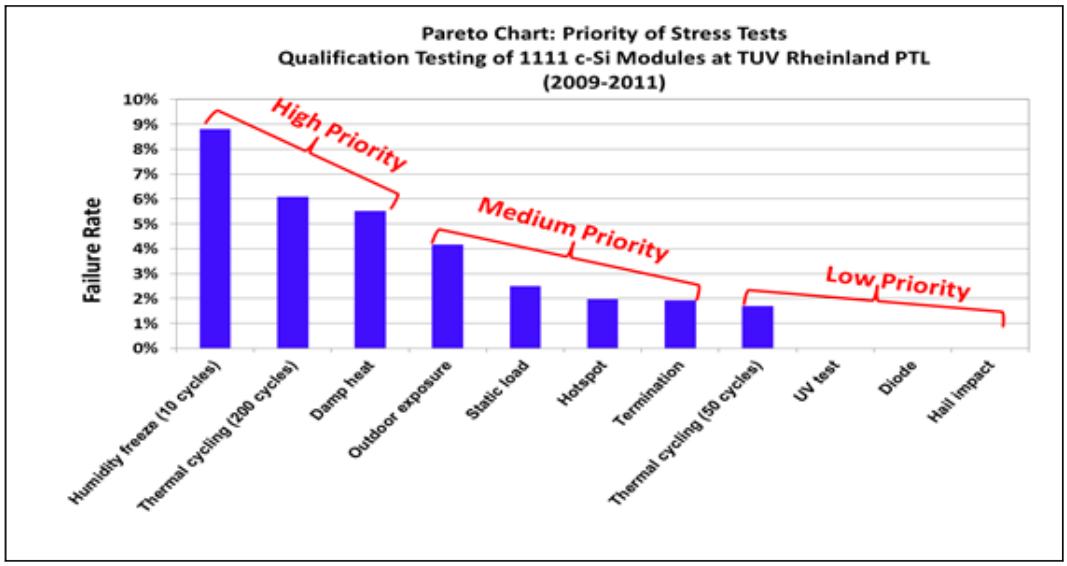


Figure 32A: Prioritization of accelerated stress tests for c-Si modules to meet the qualification testing standard of IEC 61215 (TamizhMani et al., 2012).

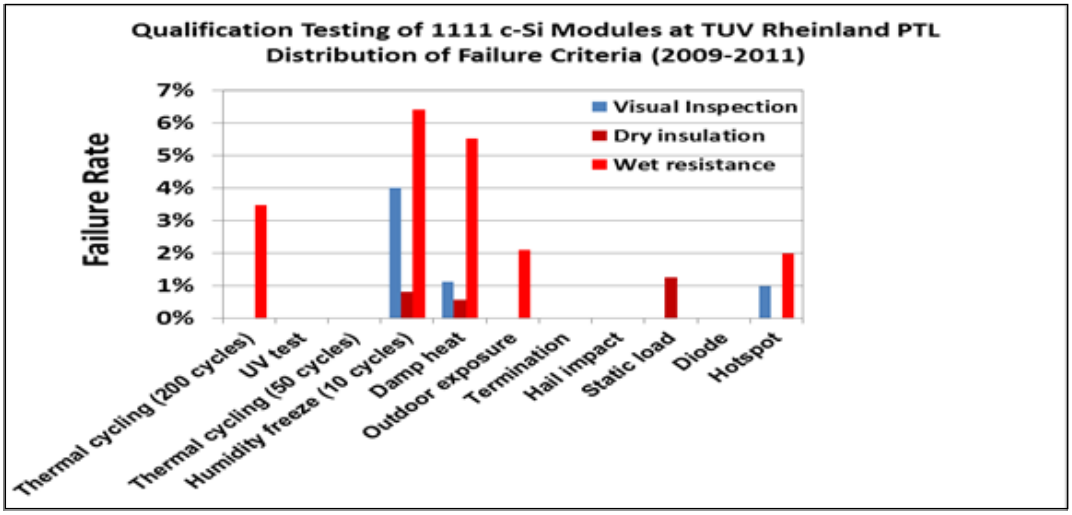


Figure 32B: Failure criteria (visual, dry, or wet) dictating the qualification failure rate for c-Si shown in Figure 32A (TamizhMani et al., 2012).

As shown in Figure 33A, the thin-film technologies are sensitive to the following top three accelerated tests to meet the pass criteria of the IEC 61646 qualification testing standard (based on the testing of 272 modules of the most recent 2009-2011 designs): humidity freeze, DH, and light soaking. As shown in Figure 33B, these post-stress failures were identified using visual inspection test, insulation test, and wet resistance failure criteria at the completion of each accelerated test of the qualification testing programs. All the other discussions presented above for the c-Si technology apply to the thin-film technologies as well.

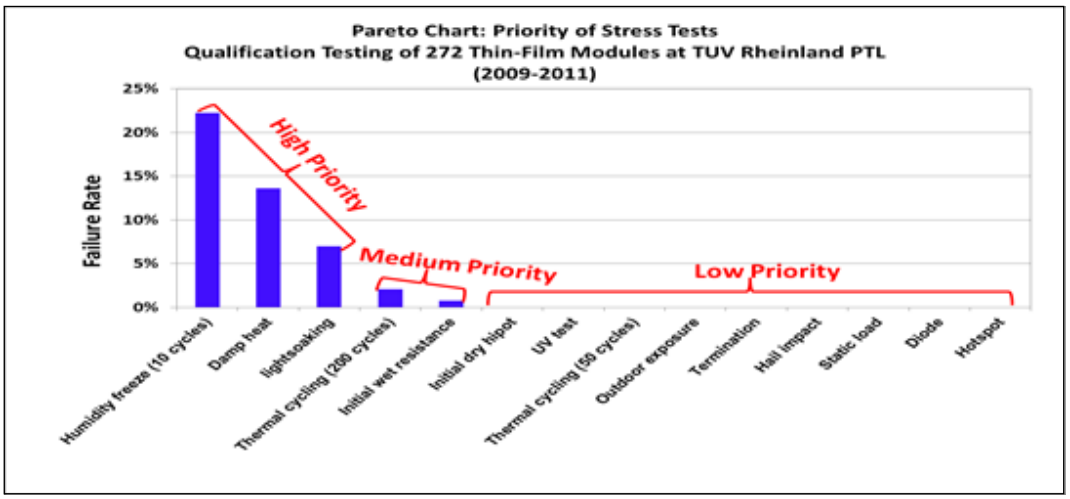


Figure 33A: Prioritization of accelerated stress tests for thin-film modules to meet the qualification testing standard of IEC 61646 (TamizhMani et al., 2012).

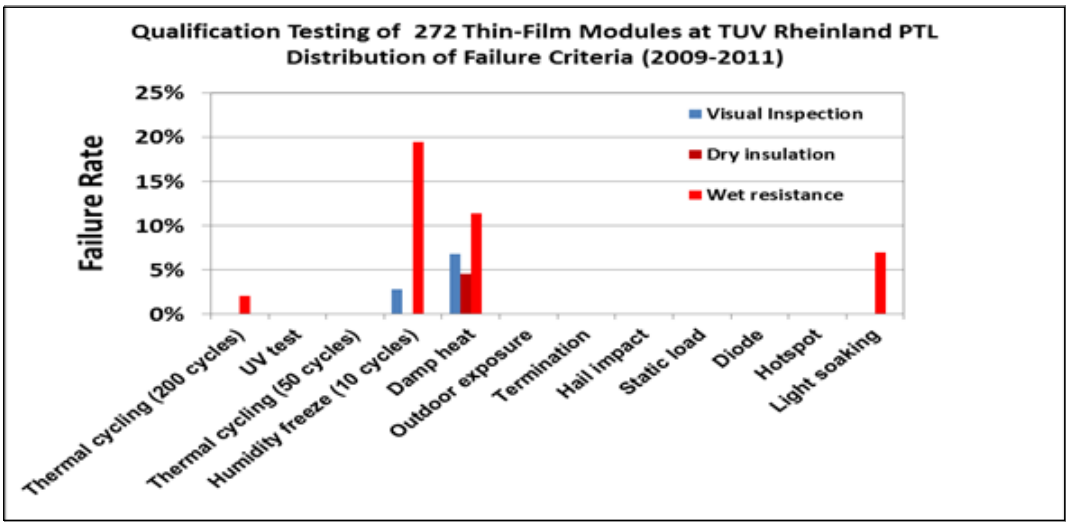


Figure 33B: Failure criteria (visual, dry, or wet) dictating the qualification failure rate for thin-film shown in Figure 33A (TamizhMani et al., 2012).

Prioritization From Durability (Degradation) Perspective

As shown in Figure 34, the post-stress qualification failures rates (identified in Figure 32A above for c-Si) are dictated not only by visual inspection observations, insulation test, and wet resistance test failure criteria but also by the power degradation criteria at the completion of each accelerated test. In the qualification testing of c-Si modules, a power degradation limit of 5% from the initial measured power is used whereas in the lifetime testing, a power degradation limit of 20% may be used assuming 20%/20-year warranty limit. In the qualification testing of thin-film modules, a power degradation limit of 10% from the rated power is used, whereas in the lifetime testing, a power degradation limit may be determined based on the warranty limit. Because—at the completion of the qualification testing programs—none of the 272 thin-film modules showed less than 90% of its rated power, no plot corresponding to the qualification failure rate due to degradation limit is presented here.

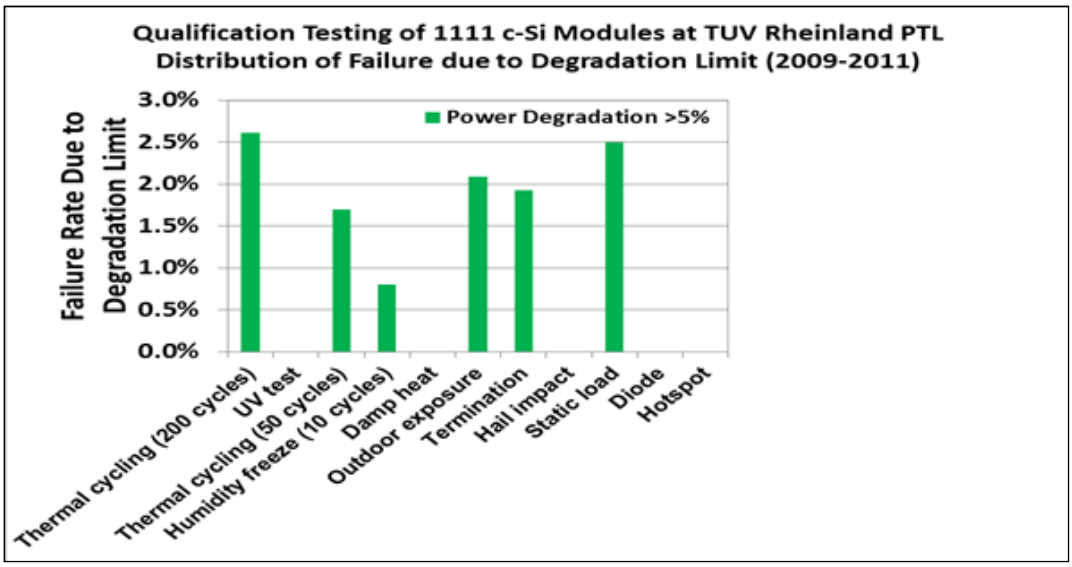


Figure 34: Degradation limit criterion dictating the qualification failure rate for c-Si shown in Figure 32A (TamizhMani et al., 2012).

Summary—Prioritization of Lifetime Accelerated Testing: There is a great need to develop a database based on the climate-specific technology-sensitive wear-out failures in the old (10-30 years) power plants that have similar or identical construction characteristics to those of the current generation modules. Based on this wear-out failure database, a set of accelerated tests needs to be identified for each of climate-specific conditions. As done in the qualification testing by independent test labs, the identified accelerated tests (which are based on the wear-out field failures) need to be carried out on a large number of commercially available PV modules to identify the statistically relevant failure rates for each climate-specific condition. Based on the statistically relevant climate-specific failure rate database, it is possible to prioritize the accelerated stress tests unique to a specific climatic condition. It is important to note that the prioritization of the accelerated tests for the lifetime testing should be based on the field-specific wear-out failures, whereas the prioritization of the accelerated tests for meeting the qualification testing requirements may be based on the qualification testing failure databases of various test laboratories.

Pre-and Post-Characterization of Materials and Modules

The chemical, physical, thermal, and electrical properties of PV materials and devices used in a PV module dictate the overall quality, durability, and reliability, which in turn dictate LCOE. Understanding these properties before and after field installations and accelerated stress tests is very important to develop less expensive but more effective materials and devices. The materials will need to be characterized before and after HALT in environmental chambers and weathering (UV-temperature-humidity) chambers. Also, the old and existing materials will need to be evaluated before and after field installations.

As a minimum, the PV cell/module characterizations should include:

- visual inspection (see the visual inspection checklist provided in the Appendix A of this report),
- current-voltage measurements under various light conditions (it is the most important characterization for the failure and degradation evaluation and it is briefly discussed below),
- spectral response/quantum efficiency,
- electroluminescence, and
- infrared scanning.

The materials and package characterizations of PV modules may include:

- water vapor transmittance of backsheets;
- optical transmission for encapsulants and superstrates;
- bulk resistivity and dielectric withstand voltage for encapsulants and backsheets;
- compositions of polymeric and cell materials;
- phase change of polymeric materials;
- contaminations inside the materials and devices;
- UV-Vis spectrophotometric analysis of materials;
- Fourier transform infrared (FTIR) of materials;
- differential scanning calorimetry (DSC) of polymeric materials;
- thermogravimetric analysis of polymeric materials;
- chromatography of polymeric materials;
- dry and wet dielectric properties of packages;
- mechanical properties of materials using universal materials testers;
- scanning electron microscopy of materials and devices;
- optical microscopy of components and devices;
- Arrhenius analysis for activation energy determination;
- impedance analysis for activation overpotential determination;
- surface and bulk resistance testing of glass, encapsulant, and backsheet; and
- moisture ingress testing.

The current-voltage measurement is the most important characterization technique for the failure and degradation evaluation of PV modules and it is briefly discussed below. To detect various failure and degradation modes due to changes in the materials and/or cells in a PV module after the accelerated tests and field exposure, the current-voltage (I-V) curves can be analyzed in several different ways including (Wohlgemuth, 2011; TamizhMani, 2012):

- multiple shoulders in an I-V curve is an indication of cell mismatch;
- increase in slope of the horizontal part of I-V curve is an indication of decrease in shunt resistance;
- decrease in slope of the falling part of I-V curve is an indication of increase of series resistance;
- a drastic decrease in open-circuit voltage may be an indicator of activation of one or more bypass diodes in the module;
- a sharp break in the I-V curve is an indication of bypass diode activation;
- a decrease in short-circuit current may be an indicator of discoloration of encapsulant, anti-reflective coating, soiling, loss of surface passivation, loss of cell area via cracking and chipping;
- a decrease in open-circuit voltage may be an indicator of loss of cells from circuit, bypass diode shorting, cell junctions shunting, and loss of surface passivation;
- a decrease in fill factor may be an indicator of solder bond thermo-mechanical fatigue, metallization corrosion, solder bonds corrosion, interconnects corrosion, interconnect ribbons broken or partially broken, and cell junctions partially shunted; and
- a decrease in module efficiency and fill factor at low irradiance levels compared to high irradiance levels is a potential indicator of cell shunting issues, so characterizing the module at different irradiance and temperature levels as per IEC 61853-1 standard would be of great interest to identify the cell shunting issues.

The use of I-V characterization for the quality, durability, and reliability evaluation of an old array (26+ years in Phoenix, Arizona; hot-dry location) is illustratively explained in the plot shown in Figure 35 (Belmont & Olakonu, to be published). Note that the short circuit current (I_{sc}) loss of about 30% in this figure is primarily attributed to encapsulant browning, but this loss may also be due to a combination of other issues identified above. The I_{sc} loss due only to encapsulant discoloration or soiling can be identified and isolated by performing complementary quantum efficiency measurements.

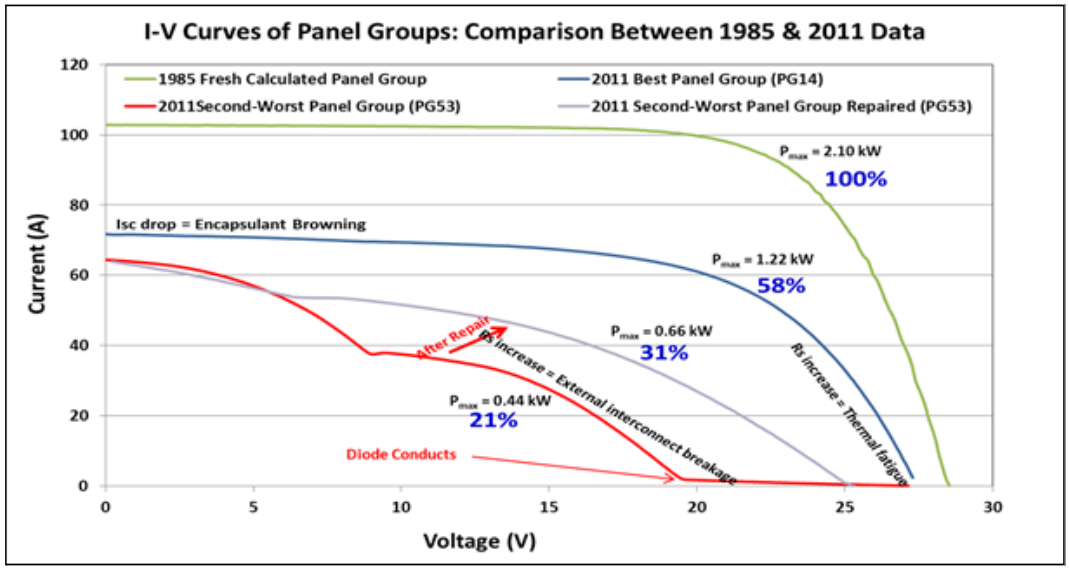


Figure 35: Use of I-V characterization in old PV power plants (panel group = 40 modules of ~55 W each) (Belmont & Olakonu, to be published).

PV ACCELERATED TESTING: PRESENT AND FUTURE PROGRAMS

Types of Accelerated Testing Programs

The purpose of AT is to shorten the test time using simulated test conditions much more severe and/or faster than the actual field operating conditions while replicating actual field failure and degradation modes and mechanisms. As shown in Figure 36, the accelerated test programs for PV modules may be classified as:

- accelerated qualification testing (minimum confidence in quality),
- accelerated comparative testing (medium confidence in quality), and
- accelerated lifetime testing (maximum confidence in quality).

The first two testing programs are qualitative AT programs and the last testing program is a quantitative AT program. In qualitative AT, the manufacturer is mostly interested in identifying failures and failure modes without attempting to make any predictions as to the product's life under normal use conditions. In quantitative AT, the manufacturer is interested in predicting the life of the product (or more specifically, life characteristics such as mean-time-to-failure, failure rate over time) at the desired use conditions, from data obtained in an accelerated lifetime testing program.

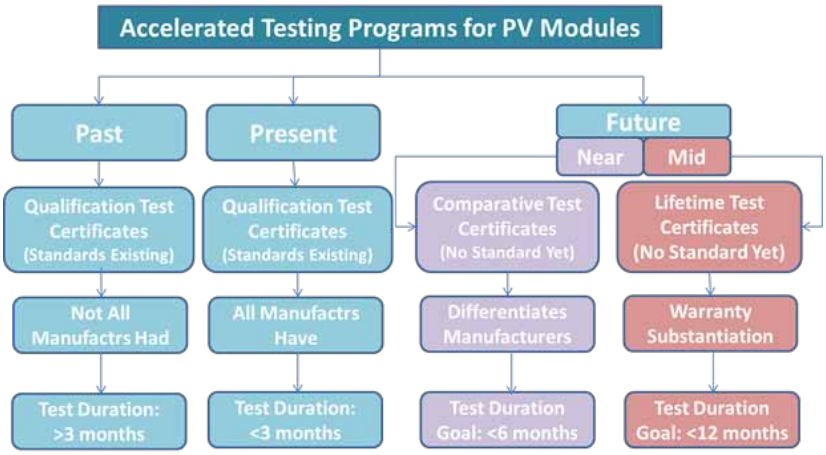


Figure 36: Past, present, and future accelerated testing programs of PV modules.

As indicated in the figure above, the standards for the qualification testing programs (IEC 61215 for c-Si, IEC 61646 for thin-film, and IEC 62108 for concentrated photovoltaics [CPV]) of PV modules have already been established and the standards for the comparative and lifetime test programs are yet to be developed. As an example, for ease of reading, the test sequence of IEC 61215 qualification standard is reproduced in Figure 37 (Wohlgemuth, 2011). Due to the high diffusion level of PV technology in the recent past (modules installed in the last 7 years account for 96% of all the modules cumulatively installed around the world), comparative and lifetime testing programs are expected, and even demanded, by consumers and investors so the products can be differentiated. Almost all PV products now have qualification certificates. A summary of all the three programs is provided in the text and in Table 6. The influence of these accelerated test programs on the reliability of PV modules are hypothetically explained in Figure 38. The test programs shown in this figure should be considered a hypothetical evolution of the test programs with due consideration to the eventual cost of the product and to statistically acceptable warranty returns.

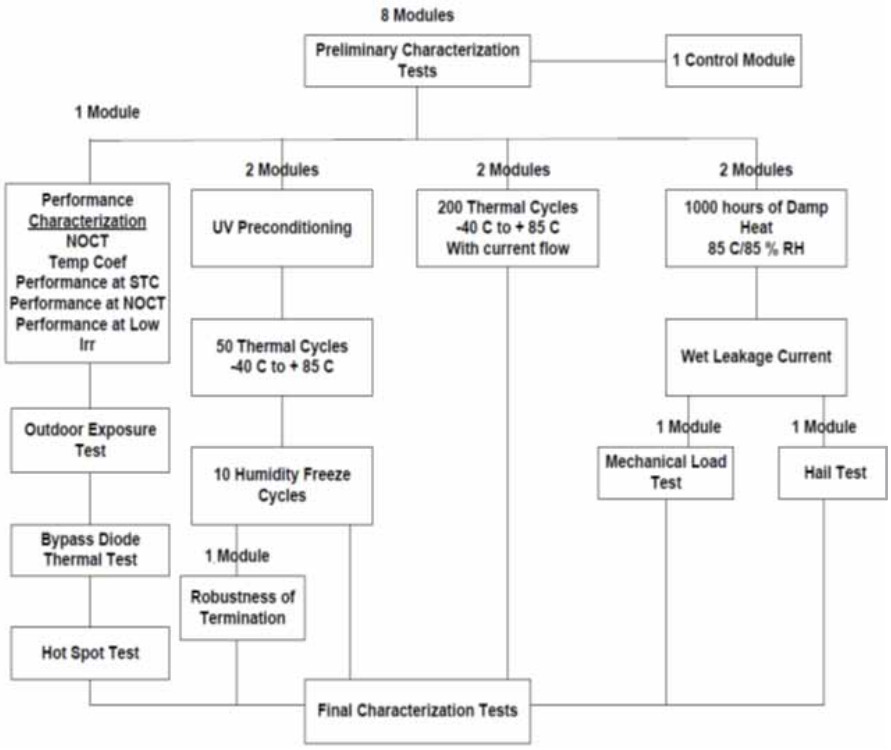


Figure 37: Test sequences of IEC 61215 qualification testing program (Wohlgemuth, 2011).

Accelerated Qualification Testing (AQT)

- Objective: The objective of qualification testing is to identify major failure modes during the initial stage in the field without attempting to make any predictions about the product's life under normal use conditions. The qualification testing defines minimum testing requirements to substantiate minimum durability (degradation) and reliability (failure) of a specific module design. This program DOES NOT attempt to account for the energy penalty over a lifetime of 20 or 25 years.
- Goal: The goal from a manufacturer perspective is to introduce the product into the marketplace with minimal required quality tests. This is a test-to-pass testing program; the testing is repeated with improved design until the modules pass this test.
- Cost and time: Minimum
- Testing protocol: Standardized protocols defined by the test standards (Examples: IEC 61215 for c-Si, IEC 61646 for thin-film, or IEC 62108 for CPV).
- Test requirement: It is a pass/fail test with a maximum allowed limit of 5% power drop per test (and 8% per test sequence) after accelerated stresses. Appendix B explains how module designs have struggled, evolved, and improved between 1997 and 2011 to meet the pass requirements of the qualification standards.

- User: Used by all manufacturers and it is a market/consumer/incentive driven requirement in Europe and around the world. The qualification standards (IEC 61215 for c-Si, IEC 61646 for thin film, and IEC 62108 for CPV) are the most extensively used PV standards in the industry. A recent publication from Wohlgemuth (Wohlgemuth, 2012b) indicated the following *"Whipple reported on 10 years of field results (using data from Rosenthal, Thomas, and Durand) that unqualified modules suffered from 45% field failure rate while qualified modules suffered from less than 0.1% field failure rate."* Unfortunately, even this minimum qualification testing is not required in the United States, except in Florida. Solar ABCs has recently released a policy statement recommending the adoption of the qualification testing requirement in the United States.

Accelerated Comparative Testing (ACT)

- Objective: The objective of comparative testing is to identify relative failures and performance losses between different designs without attempting to make any predictions as to the product's life under normal use condition. The comparative testing protocol should define extended, combined, or sequential AT requirements to compare the durability and reliability of different module designs. This program SHOULD attempt to account for the energy penalty (figure of merit) over lifetime of 20 or 25 years. For example, in the 1980s, JPL used a 10% energy/cost penalty as the figure of merit.
- Goal: The primary goal from a buyer or investor perspective is to differentiate the product designs from one manufacturer to the other in terms of their ability to survive in the field and to continue to produce power with minimal annual power loss.
- Cost and time: Medium—falls between qualification testing and lifetime testing.
- Testing protocol: Currently, several manufacturer or test laboratory defined comparative testing protocols are being used by the industry. A consensus-based uniform but climatic-specific and technology-sensitive protocol needs to be developed by a standards developing organization. Various testing laboratories, national laboratories, and manufacturers have developed several comparative testing protocols. An extended table presented in Appendix C compares these test programs. This table could serve as the basis for the development of a comparative testing standard by standards developing organization(s). The International Quality Assurance Forum (IQAF), a joint international effort from Europe, North America, and Asia, aims to develop such a high-demand protocol for the industry (see www.nrel.gov/ce/ipvmqa_task_force/ for additional details).
- Test requirement: It is a relative testing with periodic/intermittent monitoring (for failures and degradation) for a maximum allowed limit (limit the time and identify relative power loss or limit the power loss and identify relative time) defined by a standards developing organization or the consumer/investor.
- User: It could be used by the consumers or investors to compare and select appropriate climate-specific module design among various designs.

Accelerated Lifetime Testing (ALT)

- Objective: The objective of lifetime testing is to identify most, if not all, failure modes and mechanisms of the module during its entire lifetime in the field (initial, useful, and wear-out stages) with product's lifetime prediction (using statistical and physical models) under the desired field conditions. The lifetime testing protocol could define the testing requirements to predict the lifetime for any site-specific condition (and configuration). Or, the lifetime testing protocol could define the testing requirements to predict the lifetimes for the worst-case sites/climates (and configurations). This program may account for the energy penalty (figure of merit) over a lifetime of 25 years or may account for the remaining power (efficiency) through a rating system approach after 25 years of lifetime tests. For example, in the 1980s JPL used a 10% energy/cost penalty approach as the figure of merit whereas the quality assurance (QA) Task Force of IQAF appears to lean toward the rating system approach.
- Goal: It is the ultimate failure and degradation testing to predict lifetime and/or to substantiate the warranty.
- Cost and time: Maximum
- Testing protocol: Currently, none is publicly available. A unique consensus testing protocol needs to be developed based on field failure mechanisms, failure modes, and physical/statistical models. Appropriate physical and statistical distribution models will need to be developed as well. As shown in Appendix D, this testing program requires an extensive list of equipment for various standard and non-standard accelerated stress tests and pre- and post-stress/field characterizations along with physical and statistical modeling expertise. These test protocols may be developed by standards developing organization(s). As a first step, a comprehensive literature search and review needs to be conducted on the field failure and degradation modes and mechanisms, life-limiting failure modes, potential AT methods with stress/duration limits, and mathematical models. This report serves as a first step, providing a detailed literature search and review on the accelerated lifetime testing and the mathematical reliability models of PV modules. Again, the IQAF has recently instituted an all-encompassing task force to develop life testing protocols (see the website www.nrel.gov/ce/ipvmqa_task_force/ for additional details).
- Test requirement: It is a testing to determine the lifetime of the PV module design. A consensus definition for the term "lifetime" along with allowed energy penalty over lifetime will need to be developed by the standards developing organization or to be identified in the consumer-manufacturer agreement.
- User: It could be used by the individual manufacturers to determine liability for warranty returns or by consumers/investors as evidence of warranty substantiation.

Table 6

A Quick Summary Comparing Three Accelerated Testing Programs of PV Modules

	Accelerated Qualification Testing (AQT)	Accelerated Comparative Testing (ACT)	Accelerated Lifetime Testing (ALT)
Confidence level in quality	Minimum	Medium	High
Objective	Minimum testing for reliability and durability of a specific module design without attempting to make any predictions about the product's life under normal use conditions; energy penalty is not considered	Extended, combined, or sequential accelerated testing to compare relative reliability and durability of multiple designs or manufacturers without attempting to make any predictions about the product's life under normal use conditions; energy penalty should be considered	Climate-specific and technology-sensitive testing of any specific module design with product's lifetime prediction (using statistical and physical models) under normal field conditions; energy penalty should be considered
Cost and time	Low	Medium	High
Goal	Introduce the specific design into the market in a short period of time	Compare (to improve/purchase/invest in) multiple designs	Predict lifetime and/or substantiate warranty
Testing protocol	Test standards exist (IEC 61215, IEC 61646, IEC 62108)	Test laboratories or investor-defined protocols exist but a uniform/standardized protocol is needed; task group in the International PV Quality Assurance Forum has recently been created for the development of this protocol	None publicly exists; need a comprehensive understanding of failure/degradation modes/mechanisms and mathematical models to develop an appropriate testing protocol
Test requirement	Pass/Fail (>5% P_{max} drop = Fail)	Relative power loss for a specific stress time/cycles or relative stress time/cycles for a specific power loss	Identify ultimate failure mode and determine/substantiate warranty period
User	Manufacturers/Consumers/Investors	Manufacturers/Consumers/Investors	Manufacturers/Consumers/Investors

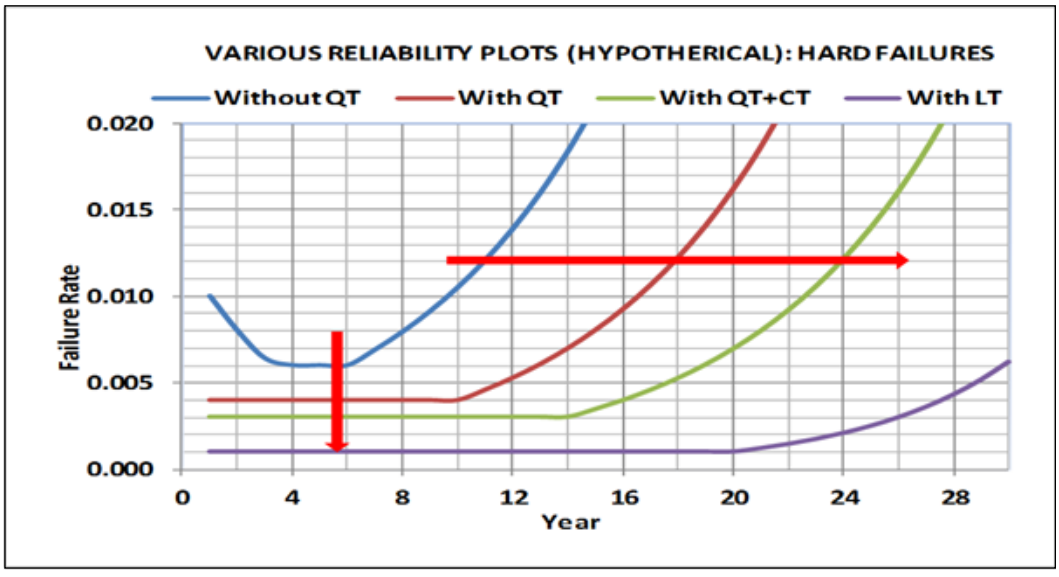


Figure 38: Influence various accelerated testing programs on reliability.

Key Attributes and Considerations for Designing Future ACT and ALT Programs

As indicated earlier, the purpose of AT is to shorten the testing turnaround time using simulated test conditions much more severe than the actual field operating conditions while replicating actual field failure and degradation modes and mechanisms. The qualification testing program takes two to three months to complete. Manufacturers cannot delay the release of products too long for financial reasons and the power plant investors cannot wait too long to make investment decisions. For these reasons, it is necessary to shorten the testing time to, for example, less than six months for comparative testing and less than 12 months for lifetime testing.

Based on the discussion presented in *PV Accelerated Testing: Stress Types, Levels, and Prioritization,* key attributes and considerations for developing future short turnaround but credible comparative and lifetime testing programs are summarized here. These attributes and considerations include stress level/cycle/ duration limits, sample preparation requirements, prioritization/extension/ combination/sequencing of stress tests, and a need for new climate-specific but technology-sensitive reliability test programs.

- Temperature
  - Temperature limit (hot end) is 90°C to avoid encapsulant related failures not seen in the field. This temperature limit may have to be increased to as high as 100°C for building integrated systems.
  - Temperature limit (cold end) is -40°C to avoid encapsulant related failures not seen in the field. This low temperature limit is already used in today's test programs.
  - Temperature dwell time (hot end): There is very limited research. Current minimum dwell time of 10 minutes per cycle at the hot end may be increased to investigate if the solder bonds fail at a higher rate and increase the series resistance without changing the failure mechanism. Recent simulation and analysis indicates that the increase of dwell time may not be helpful in shortening the time of the test (Silverman et al., 2012). However, this limited study may need to be extended and experimentally demonstrated with a large number of current commercial modules.
  - Temperature cycling rate: 100°C/h is too low for reducing test duration of comparative or lifetime testing but 400°C/h seems to be too high due to solder bond and interconnect related failures not seen in the field. The space industry has used a cycling rate up to 180°C/h and this moderate-thermal cycling rate may prove to be helpful to reduce the thermal cycling test duration (Hoffman & Ross, 1978).
  - Temperature cycle limit: It appears that 400 cycles are sufficient for a 20-year warranty, but up to 800 may be used for an extended lifetime prediction (Wohlgemuth & Kurtz, 2011; Herrmann et al., 2010).

- Humidity
  - DH limit: Current 85°C/85 % RH DH test is reported to be unrealistically severe and this limit may not be exceeded due to encapsulant related failures not seen in the field. Simultaneous stressing with < 85°C/85 % RH, UV, mechanical load, etc., may also be explored to gauge consistency with realistic field conditions.
  - DH duration: Based on the findings reported in the literature, more than 3,000 hours of DH testing may not needed or recommended due to encapsulant and backsheet related failures not seen in the field.
- UV
  - UV intensity limit: Up to 5 times the UV intensity of natural sunlight seems to be optimal. High UV transmitting glass superstrate at higher temperature with high oxygen barrier substrate such as glass would be a very good screening test to identify the browning issue of an encapsulant in a short period of time.
  - UV duration: Six to seven months with about three times the natural sunlight UV dose seems to be sufficient for a 20-year lifetime prediction.
- PID
  - PID—Voltage limit: Currently, all the researchers are using the system voltage as the stress voltage. However, this system voltage is calculated based on the open-circuit voltage value at -40°C voltage. In reality, the system voltage based on the temperature at dew point temperature (or even higher for tropical locations) may be appropriate along with the stress at high temperature (between 60°C and 85°C) and high humidity on the glass surface (> 60 % RH) as presented below.
  - PID—Temperature limit: Between 60°C and 85°C.
  - PID—Humidity limit: More than 60 % RH to shift high voltage drop from the glass surface to the cell/encapsulant interface to have same voltage distribution between glass surface and cell/encapsulant interface as seen in the field with rain in the daytime or dew on the glass surface during early morning hours.
  - PID—Sample preparation: Aluminum foil or carbon coated test method may be considered a good screening technique for the PID susceptibility investigations of the cells but it may not be a good durability test technique for the packaged modules, because it does not simulate field reality. The humidity in the field may be present on the glass surface and can also penetrate to the bulk of the encapsulant through backsheet and laminate edges, whereas the metallic layer on the glass surface does not penetrate to the bulk of encapsulant. Also, there are a few unique module/laminate mounting solutions/means adopted by the industry to avoid or reduce the PID effect, and those modules with unique mounting solutions may not be appropriately tested if the conductive metallic layer (aluminum or carbon) method is used, because it short circuits the mounting means with the glass surface.
  - PID—Sample preconditioning: The 1,000-hour DH pre-stressed modules are recommended as test samples for the PID test, because the PID issue in the field is expected be severe on aged modules compared with fresh modules.

- Prioritization of stress tests: There is a great need to develop a database based on the climate-specific technology-sensitive wear-out failures in the old (10-30 years) power plants that have passed the qualification tests and have similar or identical construction characteristics to those of the current generation modules.
- Identification of right approach for comparative testing: Various approaches for comparative testing have been developed by the industry (see Appendix C). There is a need to determine if the extended test approach, combined test approach (mechanical load during thermal cycling or light soaking during DH test, for example), or sequential test approach is appropriate to develop a new comparative test program. In the new to-be-developed comparative test program, it is important to obtain the post-stress characterization data more frequently so the failure and degradation trends can be used to develop appropriate physical and statistical models. It is important to identify those field failures that occur for modules that pass the qualification tests and to determine what set of comparative accelerated tests will cause the same or similar failures as those seen in the field.
- Climate-specific technology-sensitive lifetime testing program: Figure 39 shows the photographs of identical modules (M55; Arco Solar) installed in 1985 in Austin, Texas, and Phoenix, Arizona (twin-systems). As shown in Figure 39, identical but field-aged modules close to the end of life can have completely different wear-out failure modes and degradation modes depending on the field condition (Belmont & Olakonu, to be published). This figure clearly shows that identical modules can have encapsulant delamination (and consequent cell corrosion) failure mode in the hot-humid climatic condition, and non-cell interconnect break failure mode (and consequent bypass triggering with no arcing or bypass diode opening with arcing), encapsulant browning (I_{sc} loss with no loss in fill factor) degradation mode, and solder bond fatigue (series resistance increase with fill factor loss) degradation modes in the hot-dry climatic condition. Therefore, it is imperative to develop a climate-specific but technology-sensitive accelerated lifetime test program for the warranty substantiation and lifetime prediction of PV modules. A similar argument can be applied to the comparative testing program. This study clearly indicates that a universal comparative or lifetime testing (and corresponding rating system) may not be appropriate and may prove to be expensive as the same, for example, encapsulant needs to be tailored to tolerate both UV-related issues in the hot-dry climatic condition and humidity-related issues in hot-humid climatic condition. As shown in Figure 40, the specific climates may potentially include hot-dry, hot-humid, and hot-cold (temperate).
- Technology-blinded standard vs. technology-specific protocol: Less than 4 % of installed modules are more than seven years old and the share of the thin-film technology in this 4 % is still small. The comparative and lifetime test programs or protocols can realistically be developed only based on the field data obtained from 10 or more year-old PV modules. Therefore, from the learning-curve point of view, the comparative and lifetime testing protocols (not the standards) may first need to be developed, probably by a non-standard body such as the IQAF, for the c-Si technologies while gathering field reliability data for the thin-film technologies. It is understandable, from the marketing and level playing field points of views, to develop a technology-blinded standard and to delay the release of such a standard.

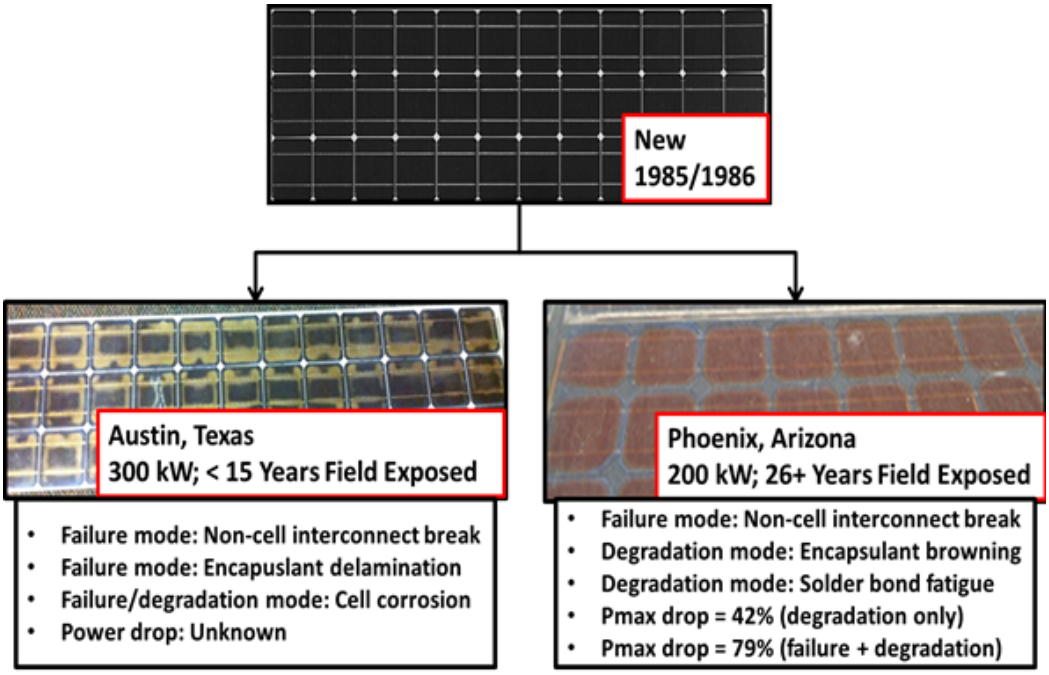


Figure 39: : Identical modules with different failure and degradation modes depending on the climatic condition (Belmont & Olakonu, to be published).

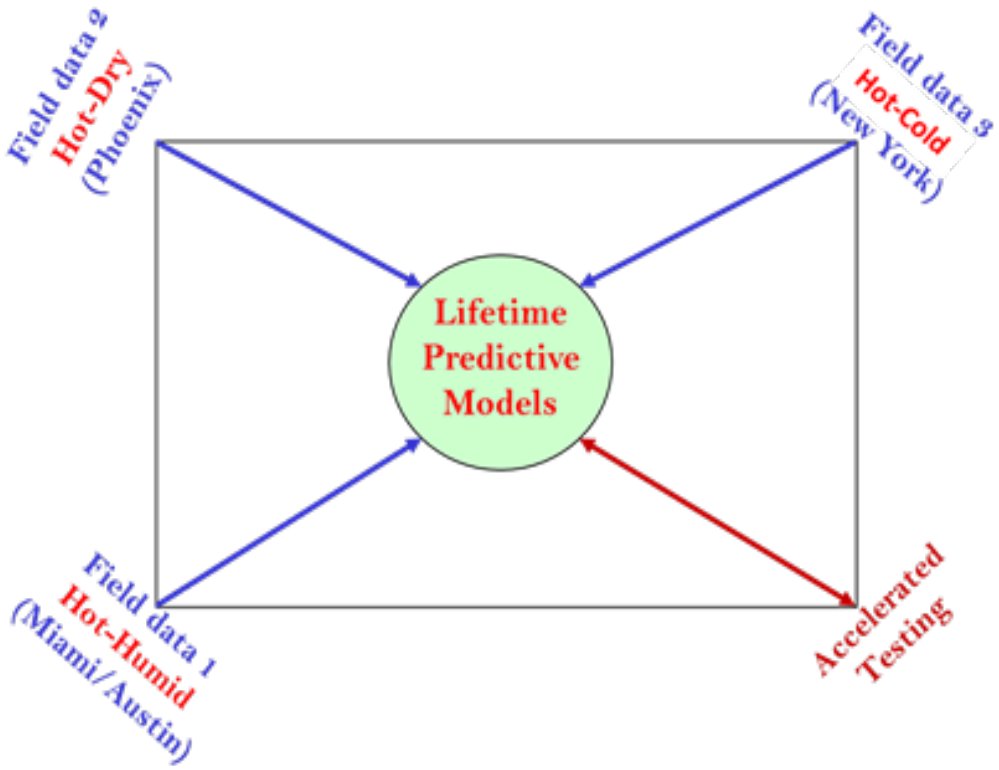


Figure 40: Potential climatic conditions to develop climate-specific lifetime testing program.

PV RATING SYSTEM: A POSSIBLE APPROACH

Based on the review, analysis, and discussion presented in this report, it becomes necessary to eventually develop a climatic-specific, technology-agnostic comparative rating system and lifetime rating system. Realistically, due to minimal availability of long-term reliability and durability data for thin-film technologies, it is challenging to develop technology-agnostic rating systems at this early stage of thin-film technology penetration and market share, and it will likely take several years to develop such a system. Consumers and investors are anxious to have a usable rating system right now, so it is important to start working—from a learning-curve perspective—on a rating system for the c-Si technology while gathering statistically significant reliability and durability data from the field for thin-film technologies. Because bankability depends on quality, reliability, and durability (Figure 41), the highest ROI for PV systems can be realized by maximizing energy production and minimizing downtime. The energy production can be maximized by producing high quality PV modules (performance/efficiency at various temperatures and irradiance levels), improving the durability (reducing degradation rate), and decreasing the downtime (reducing failure rate). Therefore, the rating system should be designed to account for the quality/performance, reliability, and durability.

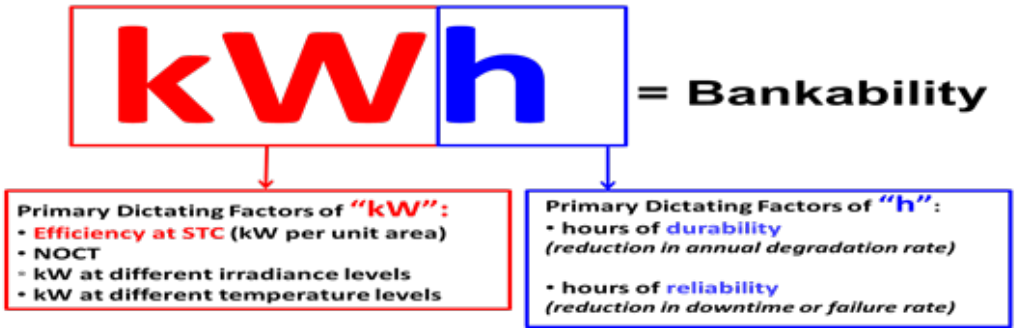


Figure 41: Bankability dictated by performance/quality, durability, and reliability.

The lifetime quality/performance, reliability, and durability characteristics can be accounted for in the rating system by assigning appropriate allocation or weighting factor for the quality of each performance parameter, degradation rate of each degradation mechanism, and failure rate of each failure mechanism. Such an approach is explained in a JPL paper published in 1982 (Ross, 1982). As shown in Figure 42, the life-cycle economic performance in 25 years should be equivalent to no degradation for 20 years (that is: to make up for the energy loss associated with failures and degradation, the product life needs to be extended for another 5 years). This equivalency allows for some gradual degradation over time but also provides for extended operation beyond 20 years, to yield a total integrated performance that is equivalent to 20 years with no degradation.

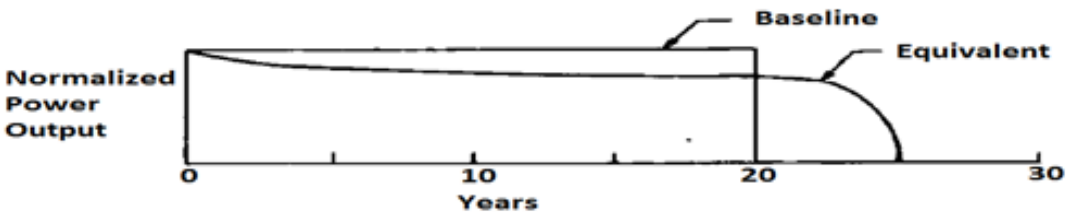


Figure 42: Life-cycle performance in 25 years should be equivalent to no degradation for 20 years.

The figure of merit for the significance of each mechanism is the level that will lead to a 10 % cost increase in the total energy from the plant (energy and economic penalty). Based on the technology maturity at that time (early 1980s) and the 10 % figure of merit, JPL developed the strawman degradation allocation shown in Table 7. A slightly modified approach may be used to develop rating systems for both comparative test and lifetime test programs, but the allocations need to be changed based on the current maturity of the technology and the expectations of the investors. Because this allocation will need to be changed for each of the major climatic conditions, a single module design is expected to receive multiple climate-specific ratings.

The rating system may be based on the reliability ratio (RR). As shown in Figure 43, the RR may be defined as the ratio between the area under predicted reliability curve and the area under the rectangular baseline curve. The area under the predicted reliability curve based on the accelerated test data may be determined using the approach used by JPL. If RR is equal to 1, the module gets the highest rating, and if it is 0.1 then it gets lowest rating. Like JPL did, the RR rating may be based on a projected quantitative energy penalty due to failures and degradation. Again, the RR rating value may not be based on a universal climatic condition but it may be based on a climatic-specific (and technology-sensitive) condition. Note that the QA Task Force of IQAF is exploring a rating system approach based on the remaining power (efficiency) after 25 years of lifetime tests.

Table 7:

Strawman Degradation Allocations for Degradations Over 25 years (equivalent to 20-year life) (Ross, 1982).

Strawman Degradation Allocations
Equivalent to 20-Year Life

Type of Degradation	Included Mechanisms	Units	Degradation Allocation
Fixed cell failure rate	Cell cracking, interconnect fatigue	Fraction per year	0.0001
Fixed module failure rate	Structural failure, insulation breakdown	Fraction per year	0.005
Linear drop in power	Yellowing, AR coating, cell degradation	Fraction per year	0.01
Fixed drop in power	Soiling	Fraction	0.05
Module wearout life	Obsolescence, corrosion	Years	25

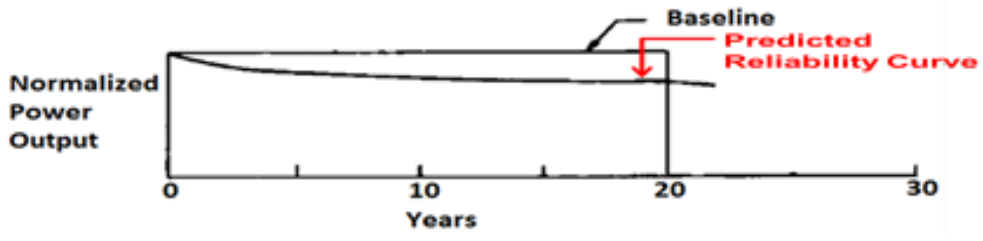


Figure 43: Reliability ratio is the area ratio between predicted reliability curve and baseline curve.

PV RELIABILITY PREDICTION: PHYSICAL AND STATISTICAL MODELS

Because only very few peer reviewed publications related to physical/empirical and statistical models of PV modules have been published in the literature, the primary focus of this section is to explain the approaches for developing appropriate statistical and physical/empirical models to predict the lifetime of PV modules. An overview on the published papers related to PV modules is also presented at the end of this section.

As shown in Figure 44, the reliability of a product is defined as the ability/probability of operating or performing under certain conditions for a certain period of time. Because the degradation losses leading to failure occur in an uncertain manner during the prolonged life of PV modules, the reliability of PV modules should be framed in a dynamic and probabilistic context. Hence, the reliability of a PV module or system may be defined as the probability that the product will perform its specified function under specified (environmental) conditions throughout its specified life expectancy.

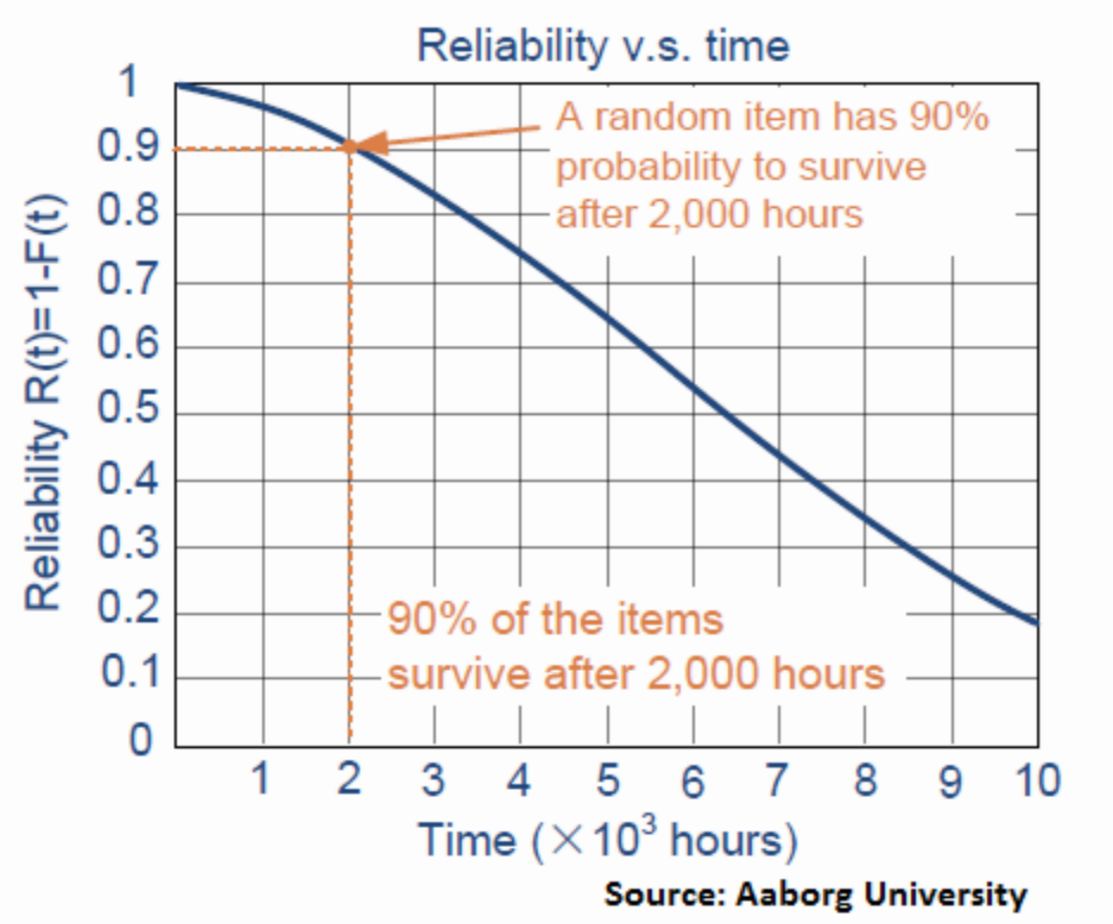


Figure 44: A hypothetical plot of reliability versus time.

AT requires extrapolation in the accelerating variable(s) and time. This implies critical importance of model choice. This section focuses on reliability modeling of PV modules. Modeling generally consists of analyzing the data to characterize the system or product, and then linking such characterization to a suitable mathematical formulation. Longrigg (Longrigg, 1989) provides a three-step summary of PV reliability modeling, methodology, and data analysis: (1) break-down the product or system into its components and analyze the criticality of individual parts; (2) for each system/product, subsystem, or component, collect and analyze either life test data or historical data on the failure rates; and (3) combine the results from (1) and (2) to obtain the reliability measure such as mean time between failure. Longrigg classifies the analysis as either statistical (operational reliability assessment from actual empirical data) or predictive (reliability estimation in the development stage from historical data).

Statistical analysis of PV module reliability data involves fitting the data to an empirical probability distribution, and then estimating the parameters of the distribution to derive the reliability characteristics such as failure rate, mean time to failure (MTTF), reliability function, etc. Murthy and Blishchke (Murthy & Blishchke, 2000) identify two approaches to modeling:

- In the "black-box" approach, the failure is modeled without consideration of the underlying mechanism. A product or component is either in a working or failed state. Typically, a component starts in its working state, and changes to a failed state after some time. Because the time to failure is uncertain, the appropriate mathematical formulation for modeling failure is a distribution function, such as exponential distribution, Weibull distribution, or lognormal distribution. This approach involves the empirical models (failure mechanism is unknown) to mathematically extrapolate the reliability characteristics from the accelerated condition to the actual use condition and the distribution models.
- In the "white-box" approach, the failure is characterized in terms of the underlying failure mechanism. Dasgupta and Pecht (Dasgupta & Pecht, 1991) categorize failure mechanisms into (1) overstress failures (interfacial deadhesion, brittle fracture, elastic deformation, etc.) and (2) wear-out failures (corrosion, diffusion, creep, fatigue crack, etc.). They also provide an alternate categorization based on the nature of the stresses that trigger the mechanism: mechanical failure, thermal failures, electrical failures, radiation failures, and chemical failures. Modeling of failure mechanisms involves the use of stochastic process formulations. This approach involves physical models (failure mechanism is known) to confidently extrapolate the reliability characteristics from accelerated condition to the actual use condition using physics/ chemistry principles and the failure mechanism models.The types of reliability/ durability data typically recorded for PV modules by the industry are degradation data; so understanding the degradation mechanisms is critical to the analysis.

  The "white-box" approach would be more appropriate, though difficult, for PV modules. Throughout this section, the focus is on aggregating laboratory test (AT) data and field (actual use) data in the context of reliability assessment. AT requires extrapolation in the accelerating variable(s) and time. This implies critical importance of model choice.

Black-Box Modeling

If we define an "acceptable" level of degradation, degradation points can be extrapolated to obtain failure times. A 20 % drop in the maximum power output is generally considered in the PV industry as an acceptable threshold. The degradation data could come either from the field or the AT. A large number of publications provide data related to field degradation of PV modules as compiled by Jordan et al. (Jordan & Kurtz, 2011). However, there are only very few or no publications related to the accelerated degradation data of PV modules available for the statistical lifetime prediction of PV modules. In this sub-section, we assume a product is either working/degrading or has failed, and the failure time of each test sample has been recorded. The modeling of failure times involves:

(1) providing a graphical representation of the failure time data (There are many charts available for that purpose, including frequency distribution charts or histograms, boxplots, pie charts, and time series charts. Histograms are widely used to provide a descriptive characterization of a product.),

(2) linking the descriptive representation above to a suitable probability distribution function and verifying your hypothesis (chosen distribution in step 1 above) using statistical tests such as chi-square goodness of fit test, and

(3) deriving the reliability characteristics from the assumed distribution.

Two black-box (underlying mechanism unknown) models can be applied for PV modules. The first is based on actual field degradation data and it is presented in Field Degradation Modeling below. The second is based on the accelerated degradation data (if assumed available) and it is presented in Accelerated Degradation Modeling .

Field Degradation Modeling

The overall approach for the first black-box modeling scenario is presented in the flow diagram in Figure 45. The eventual goal of this approach is to obtain the distribution characteristics such as MTTF based on field degradation data.

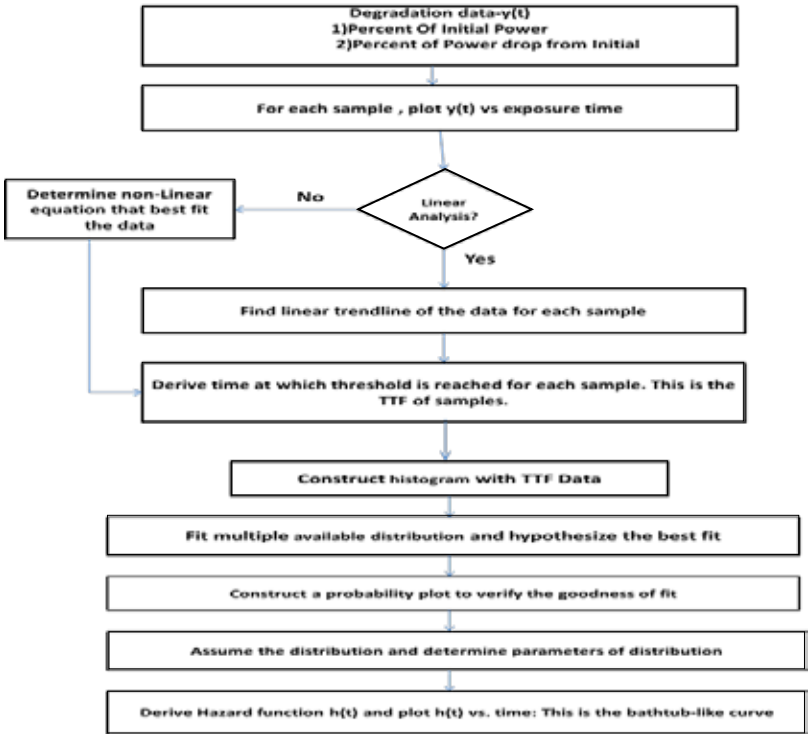


Figure 45: Flow diagram for black-box modeling using field monitored data.

The terms needed to describe and evaluate the reliability of a product are listed and briefly defined in Table 8. Note that the statistical analysis to generate these reliability characteristics should identify and appropriately account for premature failures related to workmanship issues and are not related to wear-out mechanisms that are dictating the lifetime of PV modules. This would warrant monitoring of old power plants (> 15 years) and recording failures that were caused by wear-out mechanisms. If there are workmanship issues, then there may be a few occasional spikes in the constant failure rate regime of the bathtub reliability curve. The data corresponding to these occasional spikes should not be considered in the statistical lifetime prediction, because the failure mechanisms corresponding to these spikes do not represent the normal degradation mechanisms of the product before the onset of the wear-out mechanisms (which are caused by the combination of multiple normal degradation mechanisms).

Table 8

Reliability Characteristics

Terms	Definitions
Distribution function, f(t)	probability of failure per unit of time
Reliability function R(t)	The likelihood that a product would still be operating after some time t, or R(t) = Pr (T>t)
Unreliability function	Likelihood that a product would fail by time t, or F(t) = Pr(T ≤ t) = 1 – R(t)
Failure rate, λ	Measure of failures per unit time.
Hazard rate, h(t)	Instantaneous failure rate $h(t) = \frac{f(t)}{R(t)}$ Constant hazard rate = failure rate
Mean time to failure (MTTF)	Expected lifetime of a brand new product until it fails $MTTF \int_0^\infty t\, f(t)\, dt$

The mathematical formulation appropriate for modeling TTFs is a distribution function. There are a variety of distributions available. We will focus on the ones frequently applied to PV products (Laronde, Charki, & Bigaud, 2010; Longrigg, 1989). The terms defined above are used to evaluate product reliability and are evaluated from the parameters of the assumed distribution. Table 9 provides the expressions of those terms for each distribution.

Table 9

Expressions of Reliability

Terms	Exponential distribution	Weibull distribution	Normal (lognormal) distribution
Application	Appropriate whenever failures occur randomly and are not age dependent	Popular for analyzing life data	Lognormal distribution, derived from normal distribution, is used extensively in modeling failure times, and seems very suitable for modeling semi-conductor degradation failure mechanisms
Distribution function, f(t)	$f(t) = \lambda e^{-\lambda t}$	$f\ t\ = \frac{\beta}{\eta}\left(\frac{t}{\eta}\right)^{\beta-1} e^{-(t/\eta)^{\beta}}$	$f(t) = \frac{1}{\sigma\sqrt{2\pi}} e^{-(t-\mu)^2/2\sigma^2}$
Parameters of the distribution	λ: constant	β: *shape* η: *scale or characteristic li*	μ: *mean* (normal) T_{50}: *median lifetime* (lognormal) σ: *shape* (normal & lognormal)
Reliability function R(t)	$e^{-\lambda t}$	$e^{-(t/\eta)^{\beta}}$	$R(t) = 1 - \Phi\left(\frac{t-\mu}{\sigma}\right)$
Unreliability function	$1 - e^{\lambda t}$	$1 - e^{-(t/\eta)^{\beta}}$	1 – R(t)
Failure rate, λ	$\lambda = \frac{r}{\sum_{i=1}^{r} t_i + (n-r)T}$ r failures out of n on test T = test time ti = failure time of unit i	-	-
Hazard rate, h(t)	λ	$\frac{\beta}{\eta}\left(\frac{t}{\eta}\right)^{\beta-1}$	$h(t) = \frac{f(t)}{R(t)}$
Mean time to failure (MTTF)	$1/\lambda$	$\eta\ \Gamma(\frac{1}{\beta}+1)$	$MTTF = \mu : normal$ $MTTF = T_{50} e^{\sigma^2/2} : Lognorm$

Example 1-1:

The data in Table 10 represent the PV module failure log dates for a PV system installed in Arizona (hot-dry climate) from October 2003 to December 2008. Figures 46A and 46B show the histograms assuming exponential and Weibull distributions, respectively. Taking 10/8/03 as starting point, the failure times in days were derived.

Table 10

Module Failure Log (only log dates are presented in this table; the histograms are presented in Figures 46A and 46B)

10/8/03	5/4/04	12/2/04	4/30/05	8/25/05	3/1/06	8/7/06	1/11/07	7/23/07	4/15/08
10/14/03	5/7/04	12/9/04	5/2/05	8/31/05	3/2/06	8/14/06	1/19/07	8/16/07	4/16/08
10/15/03	5/11/04	12/13/04	5/4/05	9/6/05	3/7/06	8/15/06	2/2/07	8/21/07	4/17/08
10/20/03	5/17/04	12/14/04	5/5/05	9/12/05	3/13/06	8/16/06	2/6/07	8/22/07	4/22/08
10/24/03	5/18/04	12/15/04	5/10/05	9/14/05	3/14/06	8/17/06	2/16/07	8/23/07	4/23/08
10/27/03	5/24/04	1/5/05	5/11/05	9/19/05	3/15/06	8/21/06	2/20/07	9/4/07	4/28/08
11/19/03	5/25/04	1/12/05	5/12/05	9/28/05	3/21/06	8/22/06	2/21/07	9/13/07	4/30/08
11/20/03	5/26/04	1/15/05	5/13/05	10/3/05	3/22/06	8/23/06	2/22/07	9/14/07	5/19/08
11/21/03	5/27/04	1/18/05	5/16/05	10/5/05	3/23/06	8/30/06	2/26/07	9/18/07	5/20/08
11/25/03	6/14/04	1/22/05	5/20/05	10/6/05	3/24/06	9/8/06	2/27/07	9/19/07	5/22/08
11/26/03	6/20/04	2/2/05	5/24/05	10/7/05	3/27/06	9/11/06	3/1/07	9/20/07	5/27/08
12/3/03	6/23/04	2/3/05	5/26/05	10/10/05	3/28/06	9/13/06	3/2/07	9/24/07	5/30/08
12/16/03	6/25/04	2/6/05	5/27/05	10/11/05	3/29/06	9/14/06	3/5/07	9/27/07	6/4/08
12/17/03	6/27/04	2/7/05	5/31/05	10/18/05	3/30/06	9/18/06	3/6/07	9/28/07	6/5/08
12/18/03	6/28/04	2/8/05	6/7/05	10/20/05	4/7/06	9/19/06	3/7/07	10/2/07	6/9/08
12/23/03	7/2/04	2/14/05	6/8/05	10/24/05	4/10/06	9/20/06	3/8/07	10/5/07	6/12/08
12/26/03	7/7/04	2/21/05	6/9/05	10/25/05	4/11/06	9/26/06	3/9/07	10/9/07	6/19/08
12/29/03	7/8/04	2/22/05	6/10/05	10/26/05	4/12/06	9/28/06	3/12/07	10/12/07	6/23/08
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1/13/04	7/16/04	2/25/05	6/14/05	10/28/05	4/24/06	10/10/06	3/14/07	10/18/07	7/2/08
1/16/04	7/19/04	3/1/05	6/16/05	10/31/05	4/25/06	10/11/06	3/16/07	10/19/07	7/8/08
1/18/04	7/22/04	3/2/05	6/17/05	11/1/05	4/26/06	10/12/06	3/19/07	10/22/07	7/29/08
1/26/04	7/23/04	3/7/05	6/20/05	11/2/05	4/28/06	10/13/06	3/26/07	10/23/07	8/11/08
1/29/04	8/2/04	3/8/05	6/21/05	11/3/05	5/4/06	10/18/06	3/27/07	10/25/07	8/22/08
1/30/04	8/18/04	3/9/05	6/23/05	11/8/05	5/5/06	10/19/06	3/28/07	10/30/07	8/25/08
2/3/04	8/23/04	3/11/05	6/24/05	11/9/05	5/10/06	10/31/06	3/29/07	10/31/07	9/4/08
2/5/04	8/27/04	3/14/05	6/28/05	11/24/05	5/11/06	11/1/06	3/30/07	11/6/07	9/5/08
2/6/04	9/14/04	3/16/05	6/29/05	12/1/05	5/12/06	11/3/06	4/4/07	11/7/07	9/11/08
2/10/04	9/16/04	3/17/05	6/30/05	12/2/05	5/22/06	11/6/06	4/5/07	12/2/07	9/16/08
2/18/04	9/17/04	3/18/05	7/1/05	12/16/05	5/31/06	11/7/06	4/6/07	12/7/07	9/17/08
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2/26/04	9/29/04	3/22/05	7/12/05	12/20/05	6/2/06	11/14/06	4/11/07	1/15/08	9/25/08
3/6/04	9/30/04	3/25/05	7/13/05	1/5/06	6/3/06	11/15/06	4/16/07	1/23/08	9/26/08
3/8/04	10/1/04	3/29/05	7/15/05	1/9/06	6/5/06	11/16/06	4/17/07	1/31/08	10/9/08
3/9/04	10/3/04	3/31/05	7/19/05	1/11/06	6/6/06	11/21/06	4/18/07	2/5/08	10/10/08
3/11/04	10/8/04	4/1/05	7/25/05	1/12/06	6/7/06	11/22/06	4/23/07	2/12/08	10/15/08
3/22/04	10/11/04	4/4/05	7/26/05	1/26/06	6/9/06	11/27/06	4/25/07	2/13/08	10/21/08
3/25/04	10/12/04	4/5/05	7/28/05	2/1/06	6/12/06	11/28/06	5/3/07	2/19/08	10/22/08
4/7/04	10/14/04	4/6/05	7/29/05	2/4/06	6/15/06	11/29/06	5/7/07	2/26/08	10/23/08
4/9/04	10/22/04	4/11/05	8/2/05	2/8/06	6/16/06	12/1/06	5/8/07	2/29/08	10/24/08
4/12/04	11/1/04	4/12/05	8/5/05	2/10/06	6/19/06	12/6/06	5/23/07	3/4/08	11/4/08
4/13/04	11/2/04	4/13/05	8/8/05	2/12/06	7/7/06	12/7/06	6/14/07	3/5/08	11/10/08
4/14/04	11/4/04	4/17/05	8/9/05	2/13/06	7/10/06	12/8/06	6/20/07	3/7/08	11/14/08
4/15/04	11/10/04	4/18/05	8/10/05	2/14/06	7/11/06	12/11/06	6/21/07	3/17/08	11/19/08
4/16/04	11/13/04	4/19/05	8/12/05	2/16/06	7/18/06	12/21/06	6/25/07	3/18/08	
4/20/04	11/16/04	4/20/05	8/15/05	2/21/06	7/19/06	12/26/06	6/28/07	3/31/08	
4/27/04	11/17/04	4/21/05	8/16/05	2/22/06	7/20/06	12/27/06	6/29/07	4/1/08	
4/28/04	11/18/04	4/24/05	8/19/05	2/23/06	7/28/06	1/2/07	7/11/07	4/2/08	
4/30/04	11/20/04	4/25/05	8/22/05	2/24/06	7/31/06	1/3/07	7/16/07	4/10/08	
5/1/04	11/24/04	4/26/05	8/23/05	2/25/06	8/2/06	1/4/07	7/18/07	4/11/08	
5/3/04	11/29/04	4/28/05	8/24/05	2/27/06	8/3/06	1/9/07	7/20/07	4/14/08	

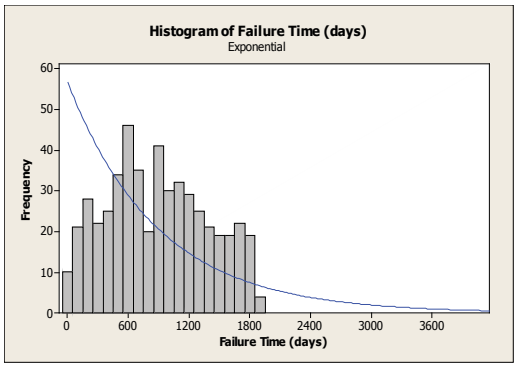


Figure 46A: Histogram of failure times (Expo)

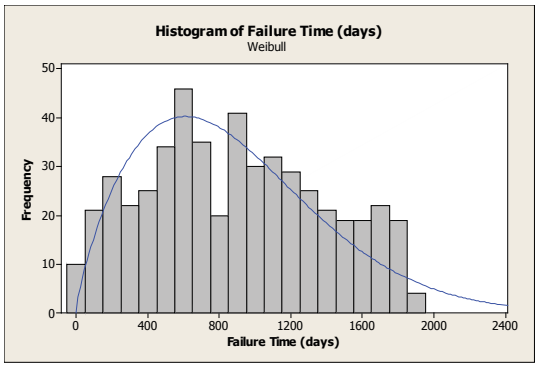


Figure 46B: Histogram of failure times (Weibull)

The Weibull distribution appears to provide a better fit than the exponential distribution. This implies that the characterization parameters obtained using the Weibull distribution are more appropriate than the ones obtained using exponential distribution.

To verify that hypothesis, the "linear rectification" procedure is used. It consists of putting the Weibull cumulative distribution function (CDF) equation into a linear form.

$$F(t)=1-\mathrm{e}^{-(t/\eta)^{\beta}} \rightarrow \ln\{-ln[1-F(t)]\}=\beta lnt-\beta ln\eta$$

$$Y=\beta X-b, \text{ where } Y=\ln\{-ln[1-F(t)]\} \text{ and } X=lnt$$

If the assumption is correct, the plot Y = f(X) should follow a fairly straight line. Because Y depends on the CDF F(t), it is necessary to estimate F(t). There are several approaches to estimate F(t). Tobias and Trindade (1995) recommended using the "median ranks" method, where the CDF estimate can be approximated to:

$$\widehat{F(t_i)}=\frac{i-0.3}{n+0.4}$$

The plot of Y = f(X) of Figure 47A appears to follow a straight line. Figure 47B also shows the "empirical CDF" plot from Minitab. These graphical observations confirm that the assumed Weibull distribution can be used to analyze the data. As noted earlier, this analysis (based on short-term monitored data) may account only for the design and workmanship related failures rather than wear-out failures.

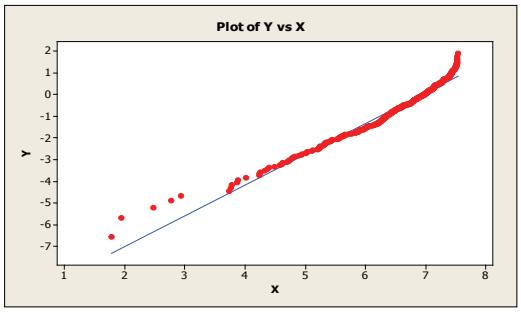


Figure 47A: Weibull probability plot.

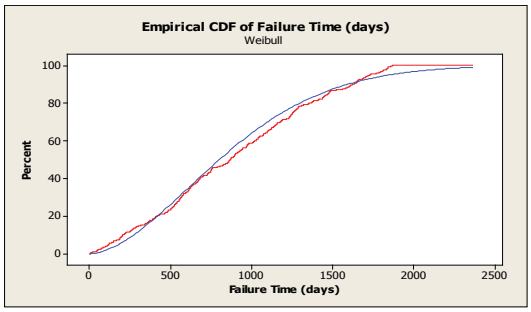


Figure 47B: Empirical CDF plot.

Example 1-2: Analysis of long-term outdoor exposure test data

Five PV modules were installed at latitude tilt in a hot desert climatic condition. After eight years of operation, the power output data were linearly extrapolated to estimate the failure time of each unit, assuming a unit would fail when its power drops by 20 % or more (infant, random, and wear-out failure mechanisms are assumed to be the same but, in reality, they may or may not be the same). The failure times in years are presented in Table 11.

Table 11

Time to Failure (TTF) for the Test Samples

Unit	TTF (years)
3801	33.41386
4821	26.93645
DG22	25.60665
DG822	20.84669
RA240	32.01457

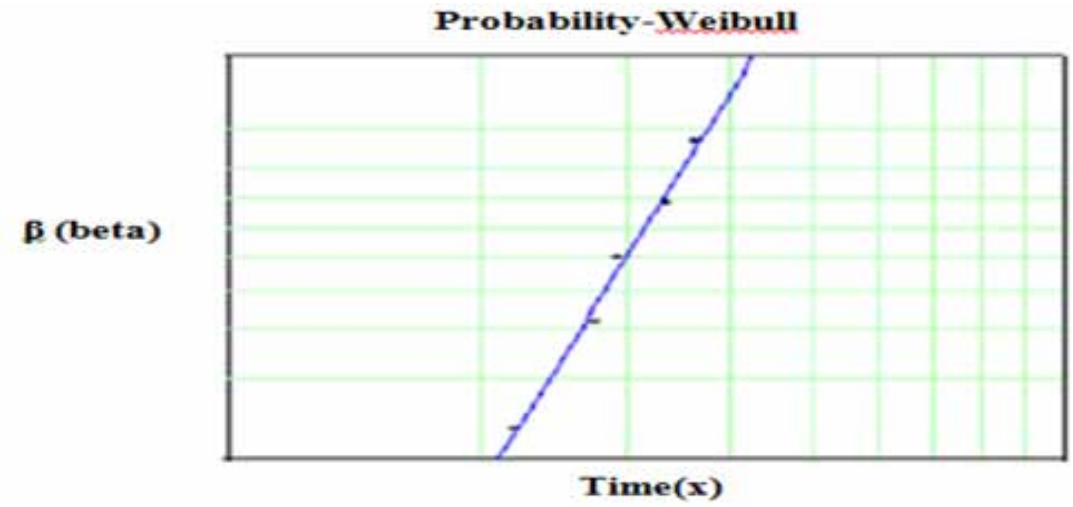


Figure 48: Weibull fit.

Those data were fitted to a Weibull distribution. As shown in Figure 48 above, all the data points are aligned along the straight line, indicating that this distribution is appropriate for analyzing the data.

Using Weibull + + 7 software, the parameters of the distribution shown in Table 12 were estimated.

Table 12

Characteristic Distribution Parameters

	Value	Lower Bound	Upper Bound
Beta (β)	5.3759	3.3	8.7484
Eta (η)	32.0597	28.5706	35.975
Mean Life (MTTF)	29.6	25.3	34.6
Failure Rate (λ)	24.3	0.2683	2208.7

The following observations can be drawn:

(1) A module from that batch would need an **average** of 29 years before seeing its power output drop below 80 %.

(2) An **average** of 24 of those samples are expected to fail per year.

This observation is made for a specific set of modules in Arizona (hot-dry climate) and this observation may or may not hold for all the existing/future modules and all the climatic conditions.

Statistical degradation data analysis

PV module degradation data are usually obtained by measuring power output of n test samples each at time ti, i = 1, 2, … and presented as shown in Table 13.

Table 13

Degradation Data Recording Format

		Time tj				
		t1	t2	…	…	tm
Sample i	1	y1,1	y1,2	…	…	y1,m
	2	y2,1	y2,2	…	…	y2,m
	…	…	…	…	…	…
	…	…	…	…	…	…
	n	yn,1	yn,2	…	…	yn,m

yi,j represents the degradation measured on sample i at time tj. Data can be collected at any time on any sample, meaning the measurement times for samples u and v need not be equal and can be denoted as tuj and tvk.

Vazquez and Rey-Stolle proposed a reliability-based model assuming normal distribution of module power output with the distribution parameters (mean and standard deviation) having a linear relationship with the time (Vazquez & Rey-Stolle, 2008). It is important to study the behavior of the power drop, rather than just the measured power.

Example 1-3:

In Figure 49, the horizontal line (10 % drop) represents the "defined" level at which failure is assumed (Twenty percent is usually considered. Ten percent is used here for illustration purposes.).

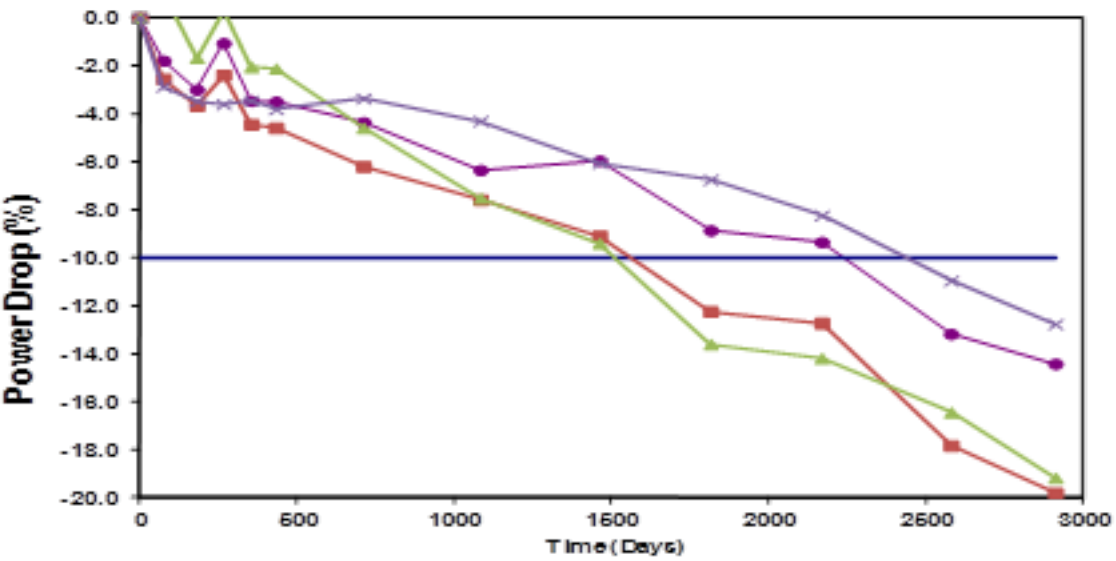


Figure 49: Power output degradation vs. time.

The following procedure is used to analyze the data:

- For each test sample, fit a mathematical model (for example, linear, exponential, power, logarithmic, …) to the performance degradation data (path curve).
- Draw a vertical line to intercept all of the sample path curves at a fixed time t = tj. Rank the intercepting power drop values yij in ascending order. The number of test samples should be large enough for statistical purposes.
- Fit yij above to an appropriate probability distribution function f(y0, 0), where 0 is the time-dependent distribution parameter vector.
- Estimate the parameters of the distribution.
- Evaluate the reliability of the product based on the specified level of degradation.

The Reliasoft Weibull + + 7 software was used to analyze the data. It provides six mathematical models to choose from—linear, exponential, logarithmic, power, Gompertz, and Lloyd-Lipow. The degradation data were fit to each of them and the exponential and linear models provided the better fits. Figure 50 shows a side-by-side comparison of the two fits. The linear model seems to best fit the data.

Table 14

Mathematical Model Coefficients and Power Drop Estimates

Model Coefficients				
Sample ID	Parameter a	Parameter b		
s15	0.00316	2.11534		
s23	0.00662	0.01582		
s90	0.00425	1.30672		
s91	0.00582	1.78719		
Estimated power drop at observation times				
Tj	s15	s23	s90	s91
75	2.352637	0.031389	1.306853	1.794787
181	2.688019	0.033608	1.306862	1.794787
266	2.956957	0.035388	1.306870	1.794787
354	3.235387	0.037230	1.306878	1.794787
433	3.485341	0.038884	1.306885	1.794787
711	4.364928	0.044705	1.306910	1.794787
1083	5.541928	0.052494	1.306943	1.794788
1462	6.741076	0.060430	1.306976	1.794788
1815	7.857960	0.067821	1.307008	1.794788
2168	8.974845	0.075212	1.307039	1.794788
2579	10.275240	0.083818	1.307076	1.794788
2911	11.325681	0.090769	1.307106	1.794789

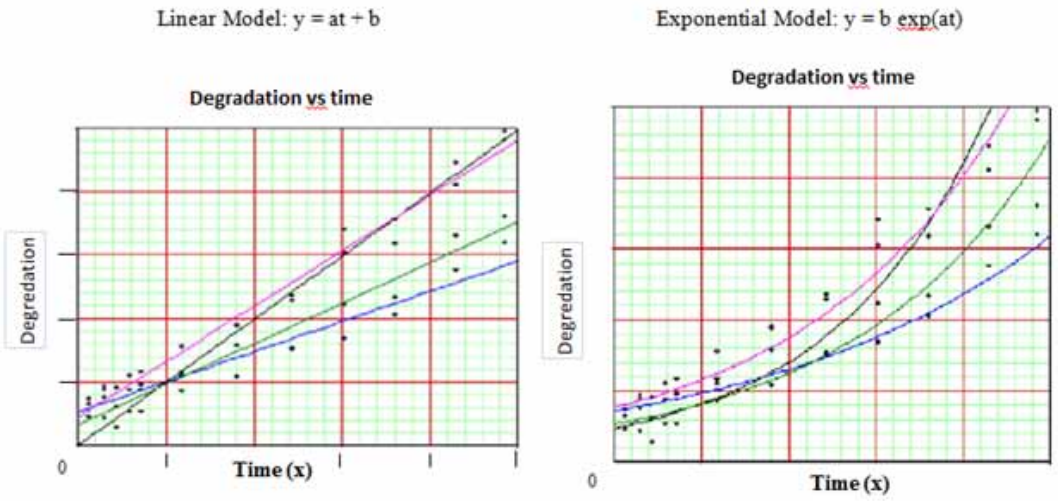


Figure 50: Mathematical model fit to the degradation data.

The model coefficients output from the software for each sample is shown at the top of Table 14. The lower half of the table shows the estimated power drop, yij, for each unit i at each measurement time tj. Note that negative drops were removed.

For each measurement time tj, the yijs are fit to an appropriate probability distribution. For degradation data analysis, the Weibull or lognormal distributions are often used.

Figure 51 shows the Weibull probability plots for six selected observation times: 1083, 1462, 1815, 2168, 2579, and 2911 days. Although the data points are not as close to the plot lines as we would wish, we will assume that these data follow a Weibull distribution for the purpose of this example. The shape (Beta) and the scale (Eta) parameters of the distribution estimated by the software are shown in Table 15.

The next step is to plot the distribution parameters vs. time. This plot is shown in Figure 52. It can be assumed from the plot that the parameter Beta is nearly constant. In fact, this observation makes sense as the shape parameter of the Weibull distribution is expected to be constant under the same environmental conditions. The scale parameter, Eta, appears to be a linear function of the time. Thus:

Beta = bo

Eta = at + b

The coefficients a, b, and bo were determined by the software to be:

bo = 0.876226

a = 4.74E-04

b = 1.481018

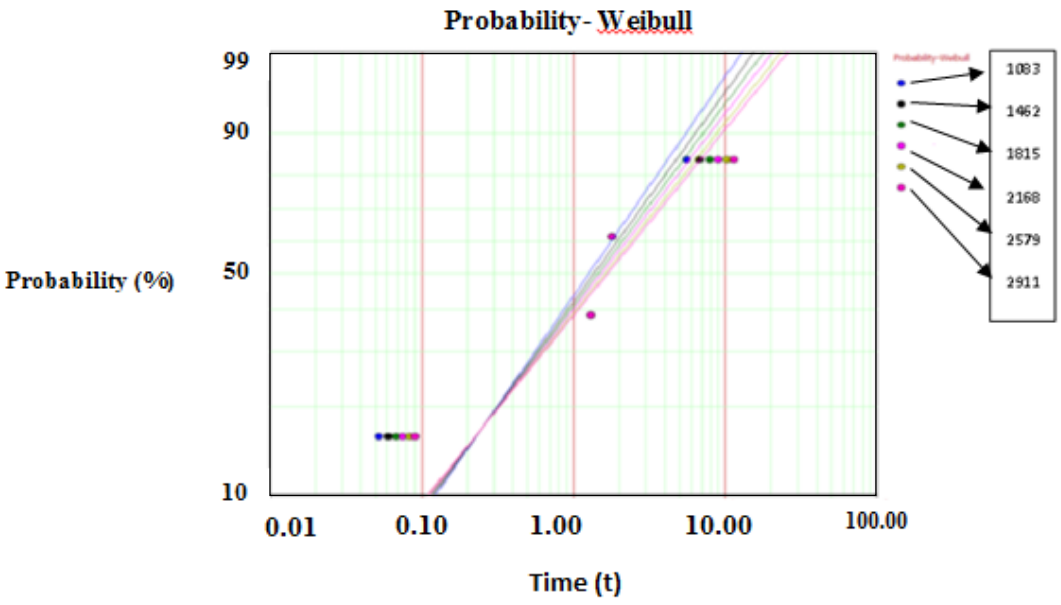


Figure 51: Weibull probability plot for the data shown in Table 14 above.

Table 15

Estimated Distribution Parameters

	1083	1462	1815	2168	2579	2911
Beta	0.81358	0.777149	0.750256	0.72794	0.706387	0.691509
Eta	1.979318	2.178436	2.353393	2.519707	2.704706	2.848166

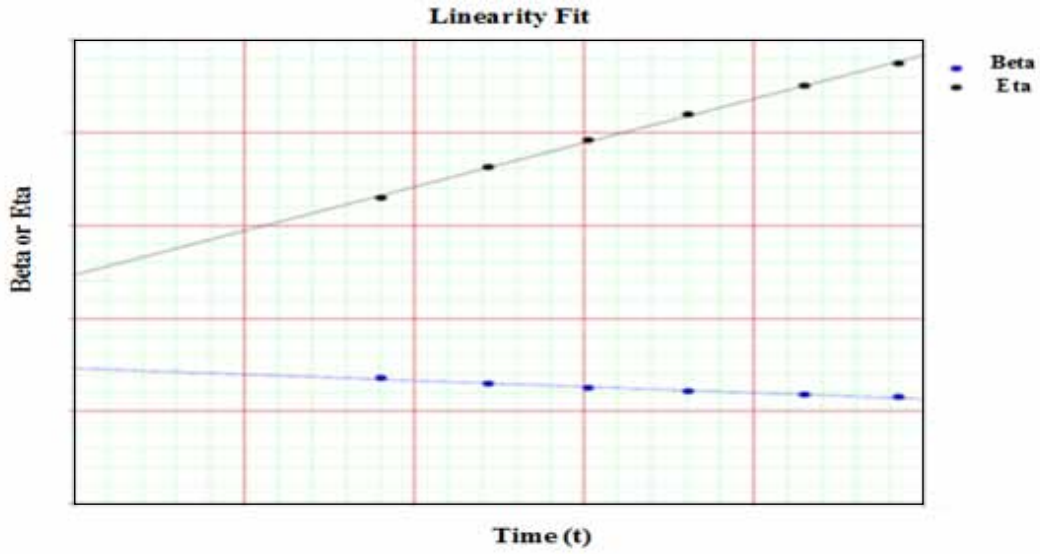


Figure 52: Plots of Weibull parameters vs. time.

To predict the reliability of these modules, recall that for a Weibull distribution, the reliability function R(t) is given by R(t) = exp(-t/Eta)^Beta.

Thus, $R(y,t) = e^{-(\frac{y}{Eta(t)})^{Beta}}$, y being the power degradation output.

Question 1: Assuming a module fails when its power output drops by more than 20%, what would be the reliability of these modules after 25 years?

The probability that the degradation y(t) is less than 20% can be expressed as F(y, t) = Pr(Y(t) < 20; because F(y, t) = 1 – R(y, t), we can substitute R(y, t).

$F(20,25) = 1 - e^{-(\frac{20}{0.000474 * 25 * 365 + 1.481018})^{0.876226}} = 0.948$

Thus, there is 94.8% chance that a random module of these types would not lose more than 20% of its power output after 25 years of operation.

Question 2: Assuming a module has degraded by 5% after eight years of operation, what would be its reliability at 25 years? We still assume 20% threshold.

This is determined using the conditional reliability concept.

Let D = 20% threshold

$$F(t = 25\text{years} \mid y1 = 5\%, t1 = 8\text{years}) = 1 - \frac{e^{-(\frac{D}{Etat(t_2)})^{Beta}}}{e^{-(\frac{y}{Etat(t_1)})^{Beta}}}$$

Accelerated Degradation Modeling

For a particular module, degradation measurements can be made over time. However, PV modules are designed to operate without significant failure or degradation for many years (20-30 years). For example, warranties of crystalline silicon modules allow for about 20 % deterioration in 20-30 years, meaning very few units would degrade significantly in a field test of, say, six months to one year. King et al. report a power drop of approximately 0.4 % per year after eight years of monitoring silicon modules (King, Quintana, Kratochvil, Ellibee, & Hansen, 2000). Ishii et al. evaluate the performance degradation of different PV technologies from 2005 to 2008 (Ishii, Takashima, & Otani, 2011). They found that the module power output was dropping at a rate of 1.3 % for amorphous silicon (a-Si) modules, 0.7 % for single-crystalline silicon modules, and 0.3 % for poly-crystalline silicon. Many studies of field installed PV modules have reportedly observed similar low degradation rates (Jordan & Kurtz, 2011).

AT is used to obtain information in a short period of time. The main goal of AT is to obtain and analyze reliability data under controlled conditions and then estimate the characteristics of interest under actual use conditions by applying an acceleration factor.

The acceleration factor (AF) relating the mean or characteristic lifetimes, say μ_1 and μ_2 at two different conditions (say controlled and used) is given by:

$$AF = \frac{\mu_1}{\mu_2}$$

If the lifetime prediction is to be done using AT, then the stress tests should be done at multiple stress levels (for example, different temperatures much higher than the use stress temperature). One TTF histogram needs to be generated for each stress level. For each histogram (that is, for each stress level), an appropriate lifetime distribution curve needs to be generated for each stress level using one of the best fit distribution models. If there are three stress levels, then there will be three lifetime distribution curves. Based on these three grouped curves, the lifetime distribution at use stress can be generated in conjunction with one of the seven life-stress models.

Five of the seven common life-stress models are used in the black-box approach. The five life-stress models used in the black-box approach are called empirical models and the other two used in the white-box approach are called physical models. The physical models are physics or chemistry based models, and empirical models are simple empirical models with no demonstrated physics or chemistry basis. A systematic approach for the black-box model based on the AT data is presented in the five steps below.

Step 1: Determine TTF for each module at each accelerated stress level.

In this step, a statistically significant number of modules is stressed at each stress level, designated here as accelerated stress 1 (AS1), AS2, and AS3. As shown in Figure 53, the time taken to reach the 20 % degradation limit is determined for each module at each stress level. Because the AS3 stress is more severe than the other two stress levels, the time taken to reach the 20 % degradation limit is much shorter than for the other two stresses.

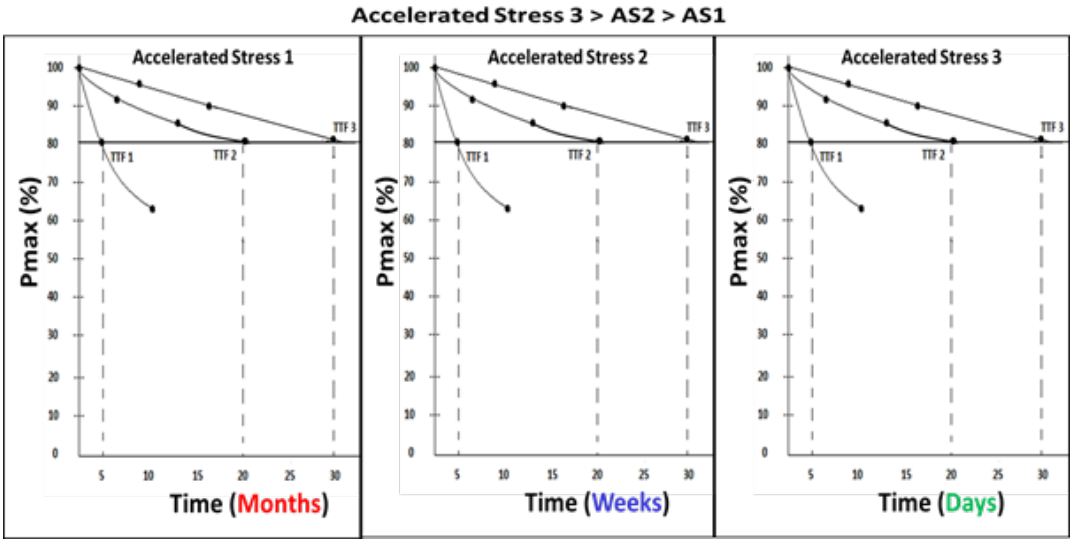


Figure 53: Determination of time to failure for each module at each accelerated stress level.

Step 2: Obtain histogram for each accelerated test level and identify the best fit failure distribution curve.

In this step, an individual histogram is obtained for each of the accelerated stress levels identified in step 1. The individual histograms are shown in Figure 54. For each histogram, the best fit distribution curve is obtained and shown as the "blue" curve in Figure 54. The goodness of the fit is verified using the procedure explained in the Field Degradation Modeling sub-section of this report.

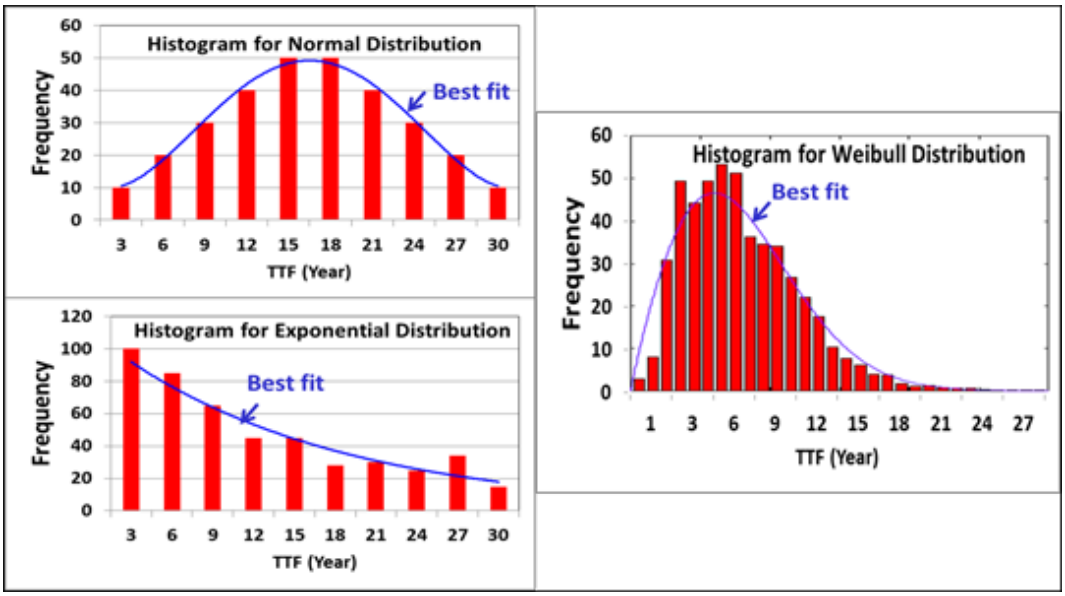


Figure 54: Determination of the best fit distribution for each histogram of all the modules at each accelerated stress level.

Step 3: Group the best-fit distribution curves of all accelerated test levels.

In step 3, the best fit distribution curves obtained in step 2 are grouped as shown in Figure 55.

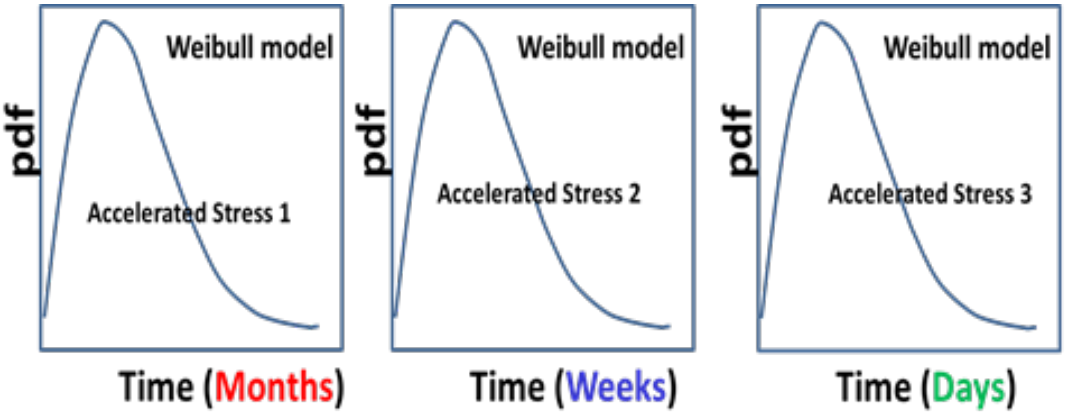


Figure 55: Grouping of the best fit distribution curves of all the modules at each accelerated stress level.

Step 4A: Obtain life-stress plot using the distribution curves of all three stress levels and an appropriate empirical model.

In step 4A, a life-stress plot shown in Figure 56 is obtained using the grouped distribution curves and an appropriate empirical model. The five "empirical" life-stress models typically used by various industries are:

1. inverse power law relationship,
2. temperature-humidity relationship,
3. temperature non-thermal relationship,
4. multivariable relationships—general log-linear and proportional hazards, and
5. time-varying stress models.

Details about these empirical models are available elsewhere (Reliawiki.Com).

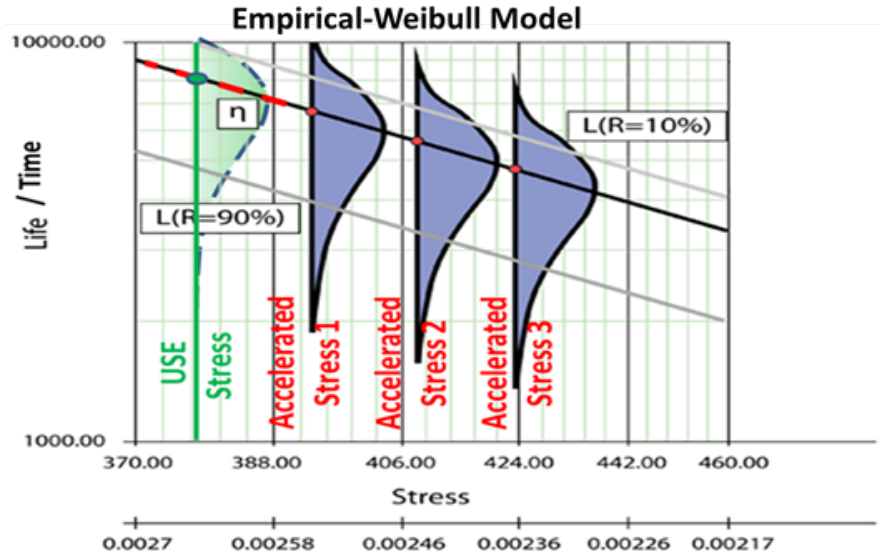


Figure 56: Life-stress plot based on the grouped distribution curves and an empirical model.

Step 4B: Determine if linear or non-linear extrapolation is to be used from accelerated stress lifetime data to use stress lifetime data.

As shown in Figure 57, it is important to select an appropriate empirical model to predict the lifetime of the product at use stress level. If not, the model may predict a wrong lifetime and this is the primary pitfall of the empirical model based extrapolation where the underlying degradation or failure mechanism is not understood.

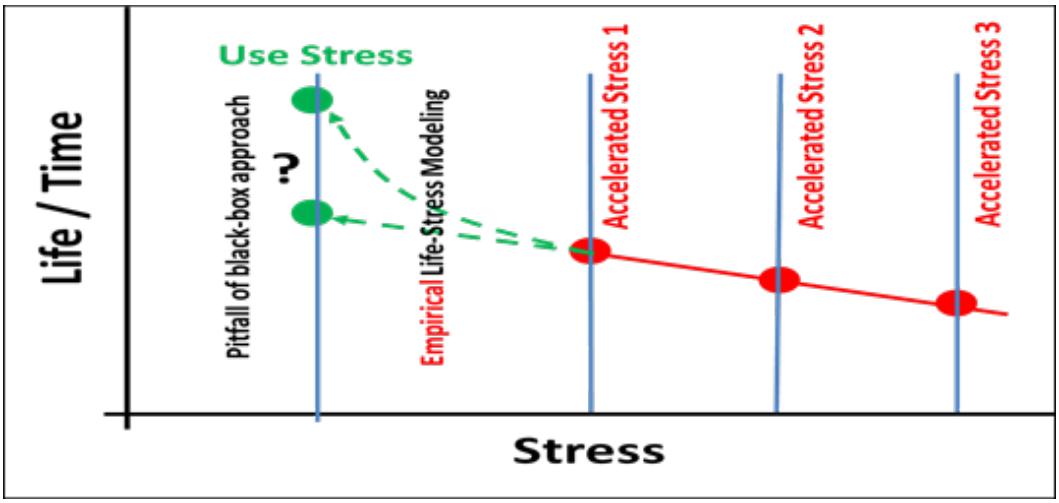
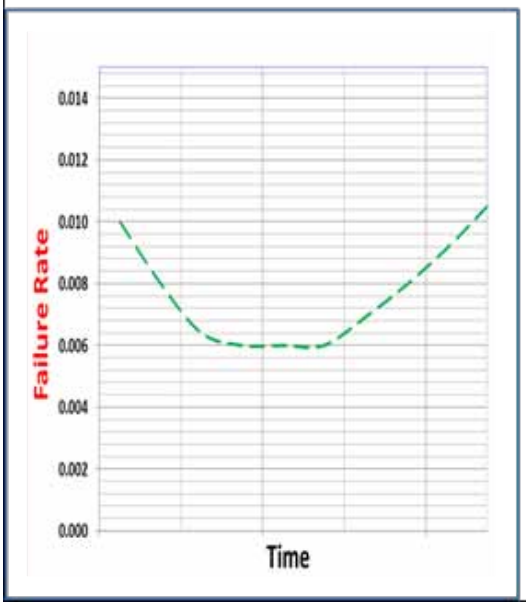


Figure 57: Life-stress plot based on the black-box approach (this life-stress plot is based on the grouped distribution curves and two different empirical models).

Step 5: Obtain the failure rate plot for use stress level and calculate all the other best fit parameters.

Based on the accelerated data, the best fit parameters for the use condition including failure rate vs. time (bathtub curve) and lifetime (MTTF) shown in Figure-Table 58 can be obtained.

Failure rate distribution



Best fit parameters including mean life

Parameter	Definitions
Distribution function, f(t)	probability of failure per unit of time
Reliability Function R(t)	The likelihood that a product would still be operating after some time t, or R(t) = Pr (T>t)
Unreliability Function	Likelihood that a product would fail by time t, or F(t) = Pr(T ≤ t) = 1 – R(t)
Failure Rate, λ	Measure of failures per unit time.
Hazard Rate, h(t)	Instantaneous failure rate Constant hazard rate = failure rate
Mean Time to Failure (MTTF)	Expected lifetime of a brand new product until it fails

Figure 58: Failure rate plot for use stress and calculated reliability characteristics data including lifetime (MTTF).

White-Box Modeling

As stated earlier, the black-box approach is based on the empirical life-stress models (failure mechanism unknown) whereas the white-box approach is based on the physical life-stress models (failure mechanism known). The white box approach uses the same five steps as the black-box approach, except in Step 4B, where the "physical" life-stress models (instead of empirical life-stress models) are used to extrapolate the data from accelerated conditions to the use condition. The physical life-stress models are based on the known failure mechanisms and hence they are expected to predict the lifetime of PV modules more accurately than the black-box models as shown in Figure 59. The most frequently used physical models are Arrhenius and Eyring models. They are briefly explained below and detailed explanations are available elsewhere (Reliawiki.Com).

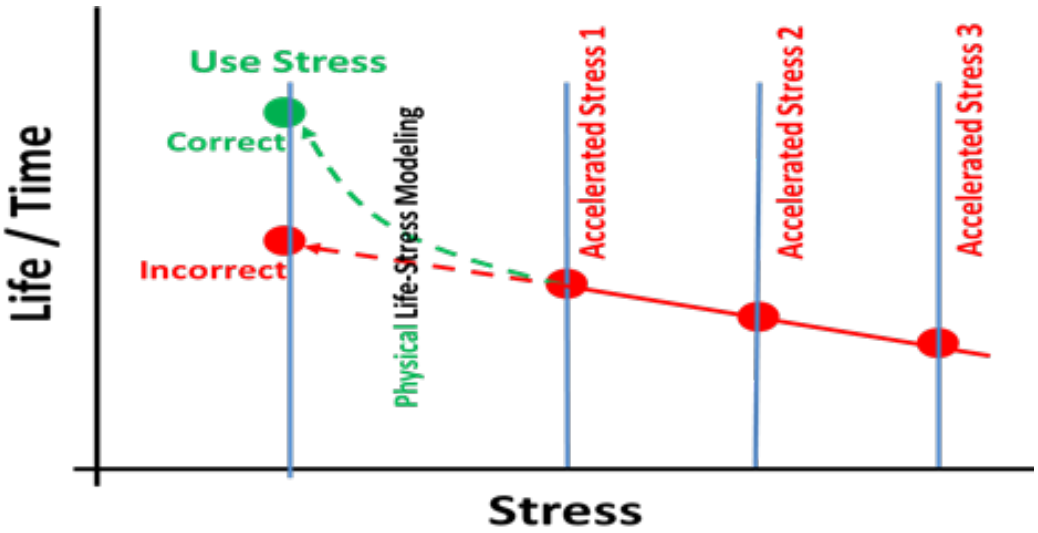


Figure 59: Life-stress plot based on the white-box approach. (This life-stress plot is based on the grouped distribution curves and two extrapolated curves. The correct extrapolated curve is based on the physical model with green dashed line and the incorrect extrapolated curve is based on the empirical model with red dashed line).

Products are subjected to higher stresses, such as temperature, voltage, humidity, etc., and the analysis requires the use of appropriate physical models that relate those stresses to normal field conditions.

For thermal stresses, the Arrhenius model is usually used. For example, Xia et al. (Xia, Wohlgemuth, & Cunningham, 2009) studied the longevity of polymer-based encapsulants and backsheets of PV modules using the Arrhenius theory to model the diffusion of moisture into a PV module. Kuznetsova et al. estimate the diffusivity at various temperatures using the Arrhenius model (Kuznetsova, Gaston, Bury, & Strand, 2009). Jorgensen et al. used the Arrhenius model to describe the permeability of PV packaging material (Jorgensen et al., 2006).

It is important to note that the Arrhenius relationship may not hold in all circumstances in which temperature is acting as the stress factor. For example, if there is more than one competing chemical reaction and those chemical reactions have different activation energies, the Arrhenius model will not describe the rate of the overall chemical reaction. A good example for two competing reactions in PV modules is the discoloration of encapsulant. The rate of discoloration of the encapsulants is dictated by two counter reactions—discoloration reaction by UV

and bleaching reaction by oxygen. Because the temperature affects the two reaction processes differently, a nonlinearity will be introduced into the acceleration function relating times at two different temperatures. To obtain useful extrapolation models for degradation processes having more than one step, each with its own rate constant, it is, in general, necessary to have adequate models for the important individual steps. For example, when the individual processes can be observed, it may be possible to estimate the effect that temperature has on each of the rate constants.

When more than one stress is involved—temperature and voltage or temperature and humidity, for example—the Eyring model can be used, but it has not been applied much in the PV industry. There are many variants of these two models in the literature, such as the inverse power model, the Coffin-Manson model, etc. Table 16 provides the Arrhenius and Eyring expressions describing the effect of related stress(es) on the MTTF or other characteristics of failure for the exponential and Weibull distributions.

Table 16

Expression of the Effect of Stresses on the MTTF or Other Characteristics of Failure

Physical Models	Significant Stresses	Exponential Distribution	Weibull Distribution
Arrhenius model	Thermal (T)	$MTTF(T) = Ae^{\frac{\Delta H}{kT}}$	$\eta(T) = Ae^{\frac{\Delta H}{kT}}$
Eyring model	Thermal (T) and a second stress S, such as voltage or humidity	$MTTF(T,S) == [AT^{\alpha}e^{\frac{\Delta H}{kT}}][e^{(B+\frac{C}{T})S}]$	$\eta(T,S) == [AT^{\alpha}e^{\frac{\Delta H}{kT}}][e^{(B+\frac{C}{T})S}]$
T = *temperature in K* ΔH = *Activation energy* k = Boltzmann's constant (8.617×10^{-5} in ev/K)			

At two different temperatures T_1 and T_2 ($T_2 > T_1$), the AF for the Arrhenius model and exponential failure time distribution is given by:

$$AF = \frac{MTTF_1}{MTTF_2}$$

$$AF = e^{\frac{\Delta H}{k}(\frac{1}{T_1}-\frac{1}{T_2})} = e^{11605\Delta H(\frac{1}{(T_1+273.16)}-\frac{1}{(T_2+273.16)})}$$

AF depends on T_1, T_2, and the activation energy ΔH

For modeling degradation data, the vector $\beta_i = (\beta_{1i}, \beta_{2i}, \ldots, \beta_{ki})$ of the degradation path expression is expressed as a function of stress(es). The examples below are from McMahon for the linear relationship (McMahon, 2004), and Meeker, Escobar, and Lu for the exponential relationship (Meeker, Escobar, & Lu, 1998):

$D(t) = k_S t$; where k_S is a function of the applicable stress. For thermal stress,

$k_S = Ae^{-\Delta H/T_S}$, T_S being the stressed or elevated temperature

$D(t) = A(1 - e^{-k_S t})$, where k_S can be defined as above.

The white-box approach consists of characterizing the failures in terms of the underlying failure mechanisms. There are many mechanisms that can lead to the failure or degradation of a PV module. McMahon et al. propose a five-step protocol for modeling PV modules lifetime (McMahon, Jorgensen, Hulstrom, King, & Quintana, 2000):

1. Identify and isolate failure mechanisms and modes.
2. Design and perform accelerated environmental testing.
3. Use appropriate statistical distribution to model specific failure rate.
4. Choose and apply relevant acceleration models to transform failure rates.
5. Develop total module failure rate as a composite of individual failure rates.

For steps 1 and 2, a good summary of the common failure modes, along with the accelerated tests that are used to analyze those known failures can be found elsewhere (Wohlgemuth & Kurtz, 2011). Steps 3 and 4 are covered in the previous sections. For step 5, the authors propose summing up individual failure rates. That is:

Let $h_k\ (t)$ denote the failure rate or hazard function for the kth failure mode. The total failure rate $h(t)$ for the M failure modes is given by:

$h(t) = \sum_{k}^{M} = 1\ h_k\ (t)$.

One key assumption, however, is that the failure modes be independent. Kuitche et al. analyzed module inspection data of 46 arrays from systems installed in Phoenix/Tempe, Arizona, and found strong correlations among many failure modes (Kuitche, TamizhMani, & Pan, 2011). This is an indication that failure times are not statistically independent for PV modules, meaning one should consider their interrelationships in assessing the module reliability.

CONCLUSIONS

Concerns about PV modules underperforming (durability) or becoming obsolete prematurely (reliability) are major barriers to PV diffusion and project financing. Accelerated testing is a way to assess the reliability and durability of PV products by inducing failures and degradation in a short period of time. It accomplishes this by using accelerated test conditions much more severe than actual field operating conditions while replicating the actual field failure mechanisms.

The detailed literature review and analysis in this report resulted in a number of observations about the current and future state of accelerated testing for PV modules. A few of these observations include:

- Based on the detailed literature review and analysis in this report, much of the information needed to develop accelerated testing protocols for comparative and lifetime testing of PV modules is available from a number of sources. These protocols can be developed through a concerted international effort along with statistically significant data sharing support from the industry. These protocols could then be converted into test standards by one or more standards developing organizations.
- The review of an extensive list of field failure and degradation modes indicates that the design, packaging, and construction of PV modules as well as the field environment in which they operate dictate their failure and degradation modes and mechanisms.
- There is a great need to develop a database of climate-specific technology-sensitive wear-out failures in old (10-30 years) PV power plants that have similar or identical construction characteristics as those of the current generation modules. Based on this wear-out failure database, a set of accelerated tests could be identified and prioritized for each climate-specific condition.
- There is little or no detailed physical and statistical modeling effort reported in the public literature, so this report attempts to present a background and detailed analysis on the physical and statistical models relevant to PV modules.
- This literature review and analysis suggests a need for the development of a climatic-specific, technology-agnostic comparative rating system and lifetime rating system. Due to the lack of long-term reliability and durability data for thin-film technologies, it is challenging to develop technology-agnostic rating systems at this early stage of thin-film technology penetration and market share. Consumers and investors are anxious to have a usable rating system right now, however, so it is important to begin work on a rating system for the c-Si technology while gathering statistically significant reliability and durability data from the field for thin-film technologies.

ACRONYMS

ACT	Accelerated Comparative Testing
AF	acceleration factor
ALT	accelerated lifetime testing
AQT	accelerated Qualification testing
AS	accelerated stress
a-Si	amorphous silicon
AT	accelerated testing
CDF	cumulative distribution function
CPV	concentrated photovoltaics
c-Si	crystalline silicon
DH	damp heat
DSC	differential scanning calorimetry
EPIA	European Photovoltaic Industry Association
EVA	ethylene vinyl acetate
FTIR	Fourier transform infrared
IEC	International Electrotechnical Commission
I_{sc}	short circuit current
I-V	current-voltage
GW	gigawatt
HALT	highly accelerated life testing
HASS	highly accelerated stress screening
IQAF	International Quality Assurance Forum
JPL	Jet Propulsion Laboratory
LCOE	levelized cost of energy
mono-Si	monocrystalline silicon
MTTF	mean time to failure
NREL	National Renewable Energy Laboratory
NTC	normal thermal cycling
PET	polyethylene terepthalate
PID	potential induced degradation
Pmax	peak power
poly-Si	polycrystalline silicon
PV	photovoltaic
QA	quality assurance
ROI	return on investment
RH	relative humidity
RR	reliability ratio
RTC	rapid thermal cycling
SiN	silicon nitride
SnPb	tin/lead
SnAg	tin/silver
Solar ABCs	Solar America Board for Codes and Standards
TC	thermal cycling
TMY	typical meteorological year
TPT	tedlar-polyester-tedlar
UV	ultraviolet

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APPENDIX A:
PV POWER PLANT VISUAL INSPECTION CHECKLIST

[A detailed report titled *"Development of a Visual Inspection Data Collection Tool for Evaluation of Fielded PV Module Condition"* on the checklist has been developed in 2012 by NREL (Packard, Wohlgemuth, & Kurtz, 2012) and it can be downloaded from the following website by using the form with the report title shown above: http://nrelpubs.nrel.gov/Webtop/ws/nich/www/public/SearchForm]

Documentation of module condition
Date _____ Name of data recorder_____
Location _____
Latitude_____ Longitude _____ Altitude _____

1. System Data

System design: ☐ single module ☐ multiple modules (a.) ☐ unknown
(a.) Multiple module system:
Module location/number in a series string (from negative) _____
# of modules in series (string) _____ # of strings in parallel (array) _____
# of bypass diodes_____ # of modules per bypass diode _____
System Bias: ☐ open circuit ☐ resistive load ☐ max. power tracked ☐ short circuit ☐ unknown
System Grounding: ☐ grounded (a.) ☐ not grounded ☐ unknown
(a.) ☐ negative ☐ positive ☐ center of string ☐ unknown

BEGIN INSPECTION AT BACK SIDE OF MODULE

2. Module Data

Technology: ☐ mono Si ☐ multi Si ☐ a--Si ☐ CdTe ☐ CIGS/CIS ☐ other: _____
Certification: ☐ unknown ☐ UL 1703 ☐ IEC 61215 ☐ IEC 61646 ☐ IEC 61730 ☐ other: _____
Estimated deployment date _____

Photo taken of nameplate: ☐ yes ☐ no
Manufacturer _____
Model # _____
Serial # _____
Installation Site/Facility Serial # _____
Width _____cm Length _____cm

Nameplate: ☐ nameplate missing
P_{max} _____ V_{oc} _____ I_{sc} _____
Sys Volt_____ V_{max} _____ I_{max} _____
Bypass diode, I_r _____
Series fuse _____

3. Rear-side Glass: ☐ not applicable ☐ applicable

Damage: ☐ no damage ☐ small, localized ☐ extensive

Damage Type (mark all that apply):
☐ crazing or other non--crack damage
☐ shattered (tempered) ☐ shattered (non-tempered) ☐ cracked (a.) ☐ chipped (b.)
(a.) Cracks (#):☐ 1 ☐ 2 ☐ 3 ☐ 4--10 ☐ >10
Crack(s) start from: ☐ module corner ☐ module edge ☐ cell ☐ junction box
☐ foreign body impact location
(b.) Chips (#): ☐ 1 ☐ 2 ☐ 3 ☐ 4--10 ☐ >10
Chipping location: ☐ module corner ☐ module edge

4. Backsheet: ☐ not applicable ☐ applicable

Appearance: ☐ like new ☐ minor discoloration ☐ major discoloration
Texture: ☐ like new ☐ wavy (not delaminated) ☐ wavy (delaminated) ☐ dented
Material quality --chalking: ☐ none ☐ slight ☐ substantial
Damage: ☐ no damage ☐ small, localized ☐ extensive
Damage Type (mark all that apply):
☐ burn marks (a.) ☐ bubbles (b.) ☐ delamination (c.) ☐ cracks/scratches (d.)

(a.)Burn marks (#):☐ 1 ☐ 2 ☐ 3 ☐ 4--10 ☐ >10
Fraction of area burned:
☐ <5% ☐ 5--25% ☐ 50% ☐ 75% --100% (consistent overall)
(b.) Bubbles(#): ☐ 1 ☐ 2 ☐ 3 ☐ 4--10 ☐ >10
Average bubble dimension: ☐ <5mm ☐ 5--30mm ☐ >30mm
Fraction of area with bubbles > 5 mm:
☐ <5% ☐ 5--25% ☐ 50% ☐ 75% --100% (consistent overall)
(c.) Fraction of area delaminated:
☐ <5% ☐ 5--25% ☐ 50% ☐ 75% --100% (consistent overall)
Fraction of delamination that exposes circuit or cell(s)
☐ <5% ☐ 5--25% ☐ 50% ☐ 75% --100% (consistent overall)
(d.) Cracks/scratches (#): ☐ 1 ☐ 2 ☐ 3 ☐ 4--10 ☐ >10
Cracks/scratches location: ☐ random/no pattern ☐ over cells ☐ between cells
Fraction of area affected by cracks/scratches (approx.):
☐ <5% ☐ 5--25% ☐ 50% ☐ 75% --100% (consistent overall)
Fraction of cracks/scratches that expose circuit (approx.):
☐ 0% ☐ 25% ☐ 50% ☐ 75% ☐ 100%

5. Wires/Connectors:

Wires: ☐ not applicable ☐ like new ☐ pliable, but degraded ☐ embrittled
(mark all that apply): ☐ cracked/disintegrated insulation ☐ burnt
☐ corroded ☐ animal bites/marks
Connectors: ☐ not applicable ☐ like new ☐ pliable, but degraded ☐ embrittled
Type: ☐ unsure ☐ MC3 or MC4 ☐ Tyco Solarlok ☐ other _____

(mark all that apply): ☐ cracked/disintegrated insulation ☐ burnt ☐ corroded

6. Junction Box:

Junction box itself: ☐ not applicable/observable ☐ applicable
Physical state: ☐ intact ☐ unsound structure
(mark all that apply): ☐ weathered ☐ cracked ☐ burnt ☐ warped
Lid: ☐ intact/potted ☐ loose ☐ fell off ☐ cracked
Junction box adhesive: ☐ not applicable/observable ☐ applicable
Attachment: ☐ well attached ☐ loose/brittle ☐ fell off
Pliability: ☐ like new ☐ pliable, but degraded ☐ embrittled
Junction box wire attachments: ☐ not applicable/observable ☐ applicable
Attachment: ☐ well attached ☐ loose ☐ fell off
Seal: ☐ good seal ☐ seal will leak
other: ☐ arced/started a fire

7. Frame Grounding:

Original state: ☐ Wired ground ☐ Resistive ground ☐ No ground ☐ unknown
Appearance: ☐ Not applicable ☐ Like new ☐ Some corrosion ☐ Major corrosion
Function: ☐ Well grounded ☐ No connection

Photos taken of ☐ back, label, and junction box

CONTINUE INSPECTION ON FRONT SIDE OF MODULE

8. Frame: ☐ not applicable ☐ applicable

Appearance: ☐ like new ☐ damaged (a.) ☐ missing
(a.) (mark all that apply): ☐ minor corrosion ☐ major corrosion ☐ frame joint separation
☐ frame cracking ☐ bent frame ☐ discoloration
Frame Adhesive: ☐ like new/not visible ☐ degraded (a.)
(a.) (mark all that apply): ☐ adhesive oozed out ☐ adhesive missing in areas

9. Frameless Edge Seal: ☐ not applicable ☐ applicable

Appearance: ☐ like new ☐ discoloration (a.) ☐ visibly degraded
(a.) Fraction affected by discoloration:
☐ <5% ☐ 5--25% ☐ 50% ☐ 75% --100% (consistent overall)
Material problems:
☐ squeezed/pinched out ☐ shows signs of moisture penetration
Delamination: ☐ none ☐ area(s) delaminated (a.)
(a.) Fraction Delaminated:
☐ <5% ☐ 5--25% ☐ 50% ☐ 75% --100% (consistent overall)

10. Glass/Polymer (front):

Material: ☐ glass ☐ polymer ☐ glass/polymer composite ☐ unknown
Features: ☐ smooth ☐ slightly textured ☐ pyramid/wave texture
☐ antireflection coating
Appearance: ☐ clean ☐ lightly soiled ☐ heavily soiled
Location of soiling:
☐ locally soiled near frame:
☐ left ☐ right ☐ top ☐ bottom ☐ all sides
☐ locally soiled on glass /bird droppings
Damage: ☐ no damage ☐ small, localized ☐ extensive
Damage Type (mark all that apply):
☐ crazing or other non--crack damage
☐ shattered (tempered) ☐ shattered (non--tempered) ☐ Cracked (a.)
☐ Chipped (b.) ☐ milky discoloration (c.)
(a.) Cracks (#): ☐ 1 ☐ 2 ☐ 3 ☐ 4--10 ☐ >10
Crack(s) start from: ☐ module corner ☐ module edge ☐ cell ☐ junction box
☐ foreign body impact location
(b.) Chips (#): ☐ 1 ☐ 2 ☐ 3 ☐ 4--10 ☐ >10
Chipping location: ☐ module corner ☐ module edge
(c.) Fraction of area:
☐ <5% ☐ 5-25% ☐ 50% ☐ 75% -- 100% (consistent overall)

11. Metallization:

Gridlines/Fingers: ☐ not applicable/barely observable ☐ applicable
Appearance: ☐ like new ☐ light discoloration(a.) ☐ dark discoloration(a.)
(a.) Fraction of discoloration:
☐ <5% ☐ 5-25% ☐ 50% ☐ 75% - 100% (consistent overall)
Busbars: ☐ not applicable/not observable ☐ applicable
Appearance: ☐ like new ☐ light discoloration(a.) ☐ dark discoloration(a.)
(a.) Fraction of discoloration:
☐ <5% ☐ 5-25% ☐ 50% ☐ 75% - 100% (consistent overall)
(mark all that apply): ☐ obvious corrosion ☐ diffuse burn mark(s) ☐ misaligned
Cell Interconnect Ribbon: ☐ not applicable/not observable ☐ applicable
Appearance: ☐ like new ☐ light discoloration(a.) ☐ dark discoloration(a.)
(a.) Fraction of discoloration:
☐ <5% ☐ 5-25% ☐ 50% ☐ 75% - 100% (consistent overall)
(mark all that apply): ☐ obvious corrosion ☐burn marks ☐ breaks
String Interconnect: ☐ not applicable/not observable ☐ applicable
Appearance: ☐ like new ☐ light discoloration(a.) ☐ dark discoloration(a.)
(a.) Fraction of discoloration:
☐ <5% ☐ 5-25% ☐ 50% ☐ 75% - 100% (consistent overall)
(mark all that apply): ☐ obvious corrosion ☐ burn marks ☐ breaks
☐ arc tracks (thin, small burns)

12. Silicon (mono or multi) module: ☐ not applicable ☐ applicable

Number of:
Cells in module _____
Cells in series/string _____
Strings in parallel _____
Cell size: Width _____ cm Length _____ cm
Distance between frame and cell: ☐ >10 mm ☐ <10 mm
Distance between cells in a string: ☐ >1 mm ☐ <1 mm
Discoloration: ☐ none/like new ☐ light discoloration ☐ dark discoloration
Number of cells with any discoloration: _____
of those, average % discolored area:
☐ <5% ☐ 5-25% ☐ 50% ☐ 75% - 100% (consistent overall)
Discoloration location(s) (mark all that apply):
☐ module center ☐ module edges ☐ cell centers ☐ cell edges
☐ over gridlines ☐ over busbars ☐ over tabbing ☐ between cells
☐ individual cell(s)darker than others ☐ partial cell discoloration
Junction box area: ☐ same as elsewhere ☐ more affected ☐ less affected
Damage: ☐ none
(mark all that apply): ☐ burn mark (a.) ☐ cracking (b.) ☐ moisture
☐ worm marks/snail tracks (c.) ☐ foreign particle embedded
(a.) Burns (#): ☐ 1 ☐ 2 ☐ 3 ☐ 4-10 ☐ >10
(b.) Number of cells cracked: _____
(c.) Number of cells with worm marks/snail tracks: _____
Delamination: ☐ none ☐ from edges ☐ uniform ☐ corner(s) ☐ near junction box
☐ between cells (a.) ☐ over cells (b.) ☐ near cell or string interconnect
(a.) Fraction delaminated between cells:
☐ <5% ☐ 5-25% ☐ 50% ☐ 75-100% (consistent overall)
(b.) Fraction delaminated over cells:
☐ <5% ☐ 5-25% ☐ 50% ☐ 75-100% (consistent overall)
Likely interface (choose 2):
☐ glass ☐ semiconductor ☐ encapsulant ☐ back sheet ☐ busbar

13. Thin film module: ☐ not applicable ☐ applicable

Number of cells:
Number of cells in module _____
Number of cells in series/string _____
Number of strings in parallel _____
Cell size: Width _____ cm Length _____ cm
Distance between frame and cell: ☐ >10 mm ☐ <10 mm
Appearance: ☐ like new ☐ minor/light discoloration ☐ major/dark discoloration
Discoloration type (mark all that apply):
☐ spotted degradation ☐ haze (encapsulant browning) ☐ other

Discoloration location (mark all that apply):
☐ overall/no location pattern ☐ module center ☐ module edge(s)
☐ cell center ☐ cell edges ☐ near crack(s)

Damage: ☐ no damage ☐ small, localized ☐ extensive

Damage Type (mark all that apply): ☐ burn mark(s) ☐ cracking
☐ possible moisture ☐ foreign particle embedded

Delamination: ☐ no delamination ☐ small, localized ☐ extensive

Location: ☐ from edges ☐ uniform ☐ corner(s) ☐ near junction box ☐ near busbar
☐ along scribe lines

Delamination Type: ☐ absorber delamination ☐ AR coating delamination ☐ other

Photos taken of ☐ front and defects

14. Electronic Records ☐ not applicable ☐ applicable
Photographs and I--V curves recorded electronically--list file names in blanks
Photo files _____
I--V curve _____
Connector function: ☐ functions ☐ no longer mates ☐ exposed
Irradiance _____Sensor _____
Temperature _____Sensor _____
EL picture _____
IR picture_____
Bypass Diode Test: ☐ not applicable ☐ applicable
Number of diodes:
In total_____, shorted_____, open_____

OTHER

APPENDIX B: EVOLUTION OF MODULE DESIGN QUALITY BETWEEN 1997 AND 2011

Figures B-1 and B-2 present the accelerated qualification test failure data of more than five thousand modules between 1997 and 2011 (TamizhMani et al., 2012). Figure B-1, corresponding to c-Si modules, indicates that the failure rate was low before 2005, became high in 2005-2007, and became low again after 2007 with lowest being between 2009 and 2011. Because the number of new manufacturers with limited module design and manufacturing experience became very high (from less than 50 old manufacturers to more than 200 new manufacturers) during 2005-2007 time period, the failure rate in the accelerated qualification testing dramatically increased. Ignoring the 2005-2007 data, the failure rates of various accelerated tests of the old modules (before 2005) and recent modules are nearly the same for the 2007-2009 period or even lower for the 2009-2011 period. If one assumes and proves that the accelerated qualification failure data for the periods after 2007 represent the infant/early field failure data (if made available) of the recent field installed modules (more than 80% of the cumulative installed modules have come from the modules produced after 2007), then one may tend to use the future qualification failure data (generated by independent test labs) to predict the infant failure rates of future field installed modules. In all these historical failure reporting years (1997-2011). The failure rates in the qualification testing of crystalline silicon modules were primarily influenced by the change in the number of manufacturers with varied manufacturing experience. However, in future, the trend of failure rates in the qualification testing of crystalline silicon modules may strongly be influenced by the change in the module construction materials and radically different designs and manufacturing processes. As shown in Figure B-3, the SunShot program aims to reduce the price of the module from about $2/W to about $0.5/W by primarily reducing the costs of module construction materials and manufacturing processes (U.S. Department of Energy, 2012). The change in construction materials includes the wafer (thickness), encapsulant, backsheet, edge seals, mounting hardware, cable connectors, cell interconnections, bus bars, and junction boxes. All these material level changes are expected to have significant influence in the failure rates of future qualification testing programs.

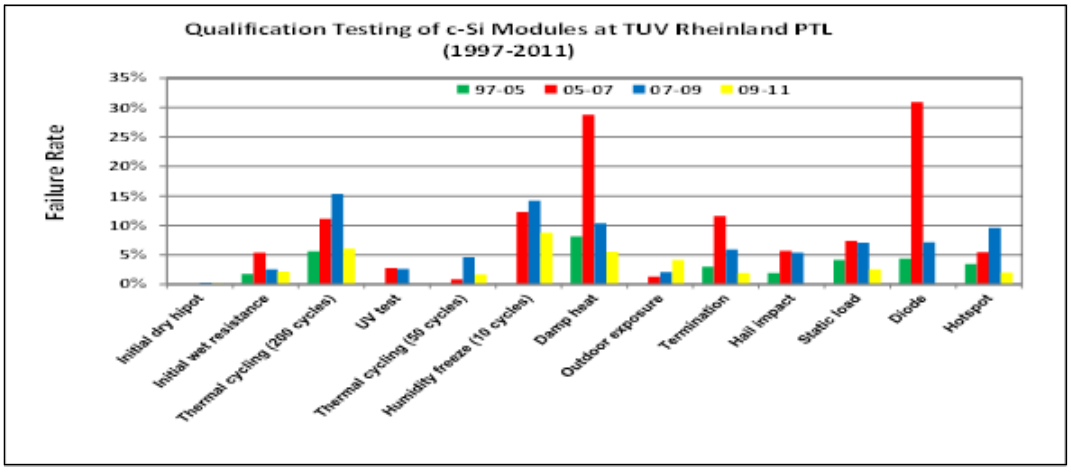


Figure B-1: Failure rates of crystalline silicon PV modules in qualification testing (TamizhMani et al., 2012).

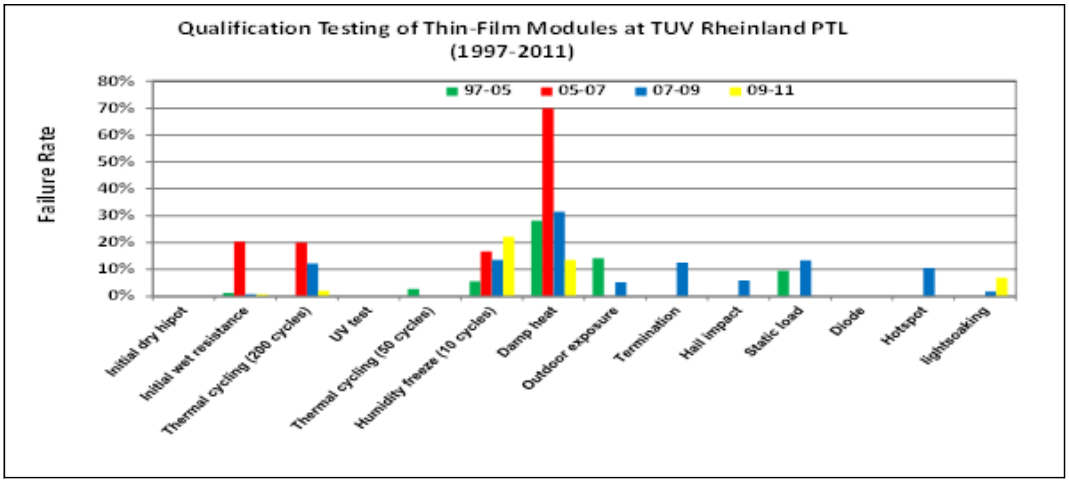


Figure B-2: Failure rates of thin film PV modules in qualification testing (TamizhMani et al., 2012).

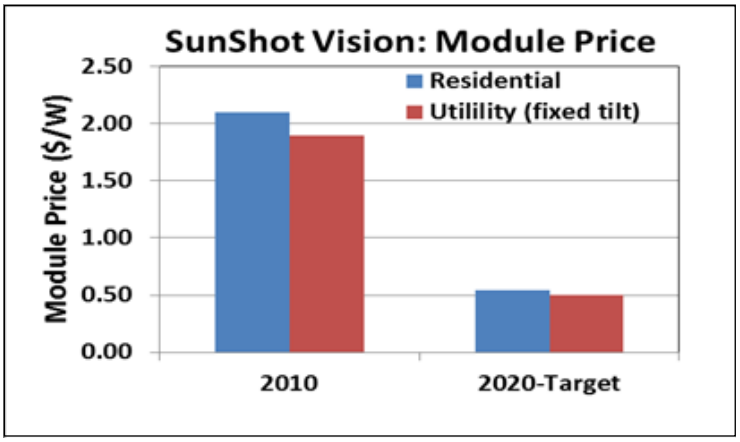
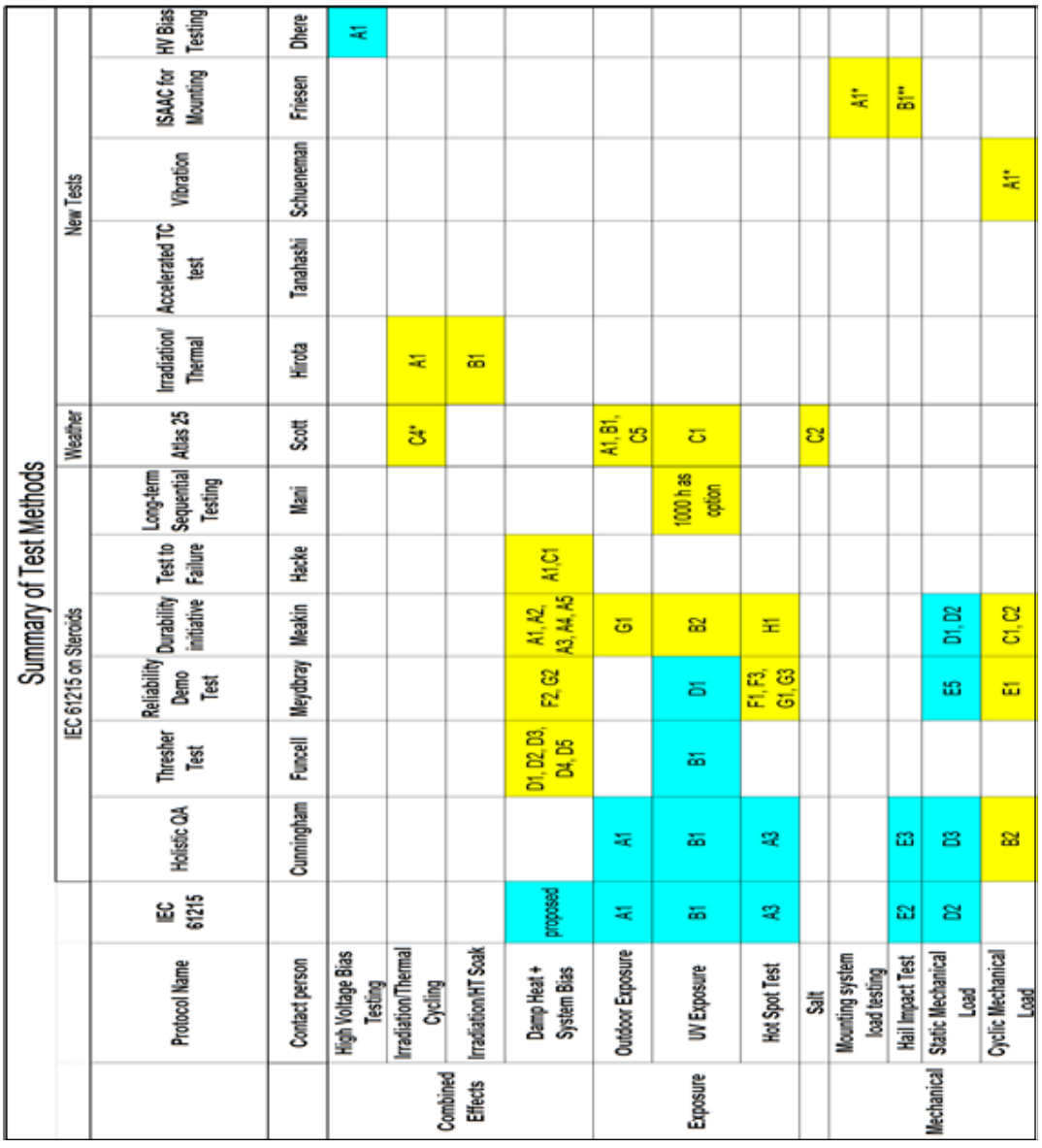


Figure B-3: Target reduction of module price by reducing cost of materials, manufacturing processes, and shipping (U.S. Department of Energy, 2012).

APPENDIX C:

SUMMARY OF COMPARATIVE TESTING PROGRAMS DEVELOPED BY VARIOUS ORGANIZATIONS

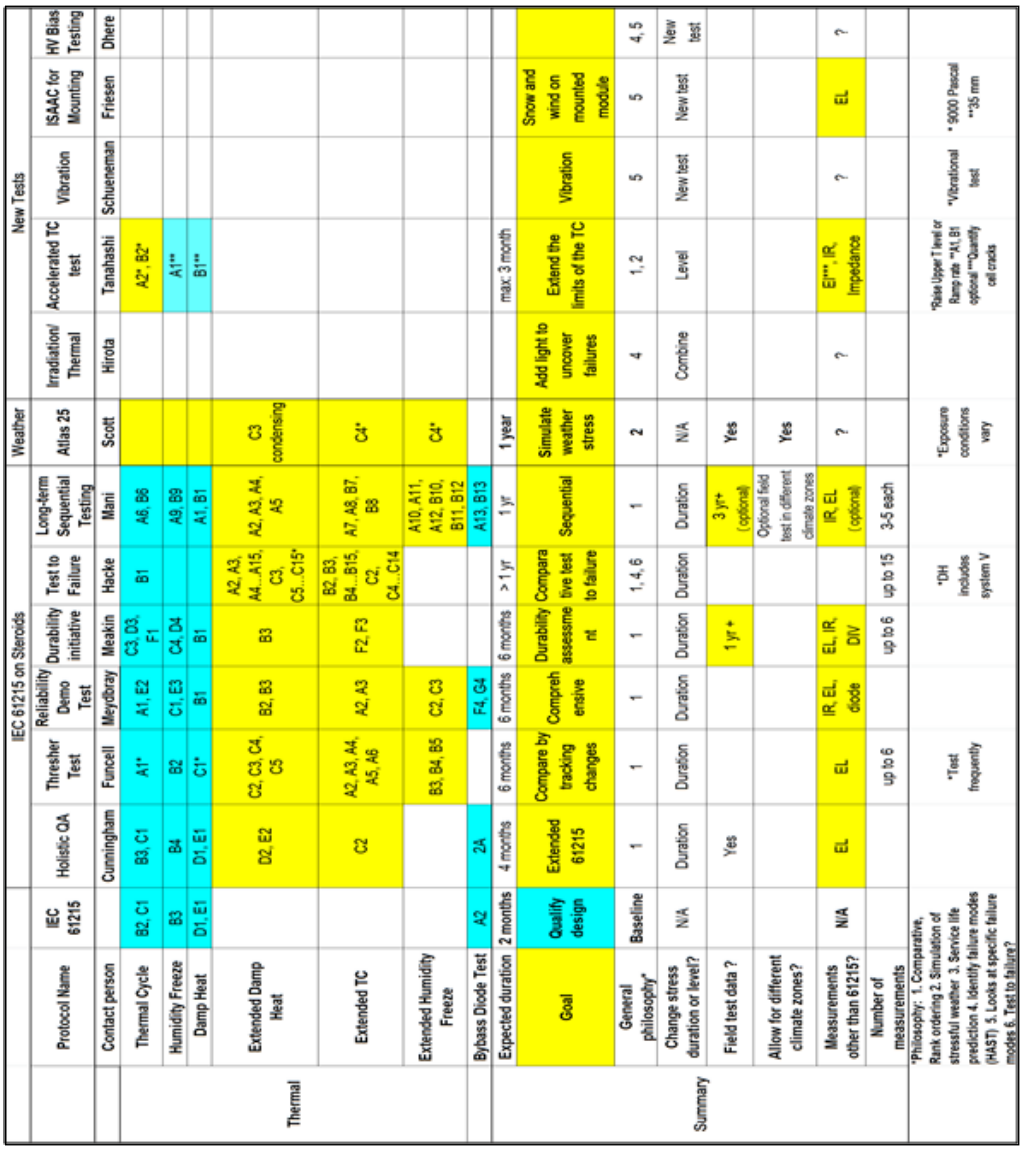
(NREL, 2012)



Summary of Test Methods

			IEC 61215 on Steroids							Weather	New Tests					
	Protocol Name	IEC 61215	Holistic QA	Thresher Test	Reliability Demo Test	Durability initiative	Test to Failure	Long-term Sequential Testing	Atlas 25	Irradiation/ Thermal	Accelerated TC test	Vibration	ISAAC for Mounting	HV Bias Testing
	Contact person		Cunningham	Funcell	Meydbray	Meakin	Hacke	Mani	Scott	Hirota	Tanahashi	Schueneman	Friesen	Dhere
Combined Effects	High Voltage Bias Testing													A1
	Irradiation/Thermal Cycling								C4*	A1				
	Irradiation/HT Soak									B1				
	Damp Heat + System Bias	proposed		D1, D2, D3, D4, D5	F2, G2	A1, A2, A3, A4, A5	A1,C1							
Exposure	Outdoor Exposure	A1	A1			G1			A1, B1, C5					
	UV Exposure	B1	B1	B1	D1	B2		1000 h as option	C1					
	Hot Spot Test	A3	A3		F1, F3, G1, G3	H1								
	Salt								C2					
Mechanical	Mounting system load testing												A1*	
	Hail Impact Test	E2	E3										B1**	
	Static Mechanical Load	D2	D3		E5	D1, D2								
	Cyclic Mechanical Load		B2		E1	C1, C2						A1*		

SUMMARY OF COMPARATIVE TESTING PROGRAMS DEVELOPED BY VARIOUS ORGANIZATIONS (NREL, 2012)



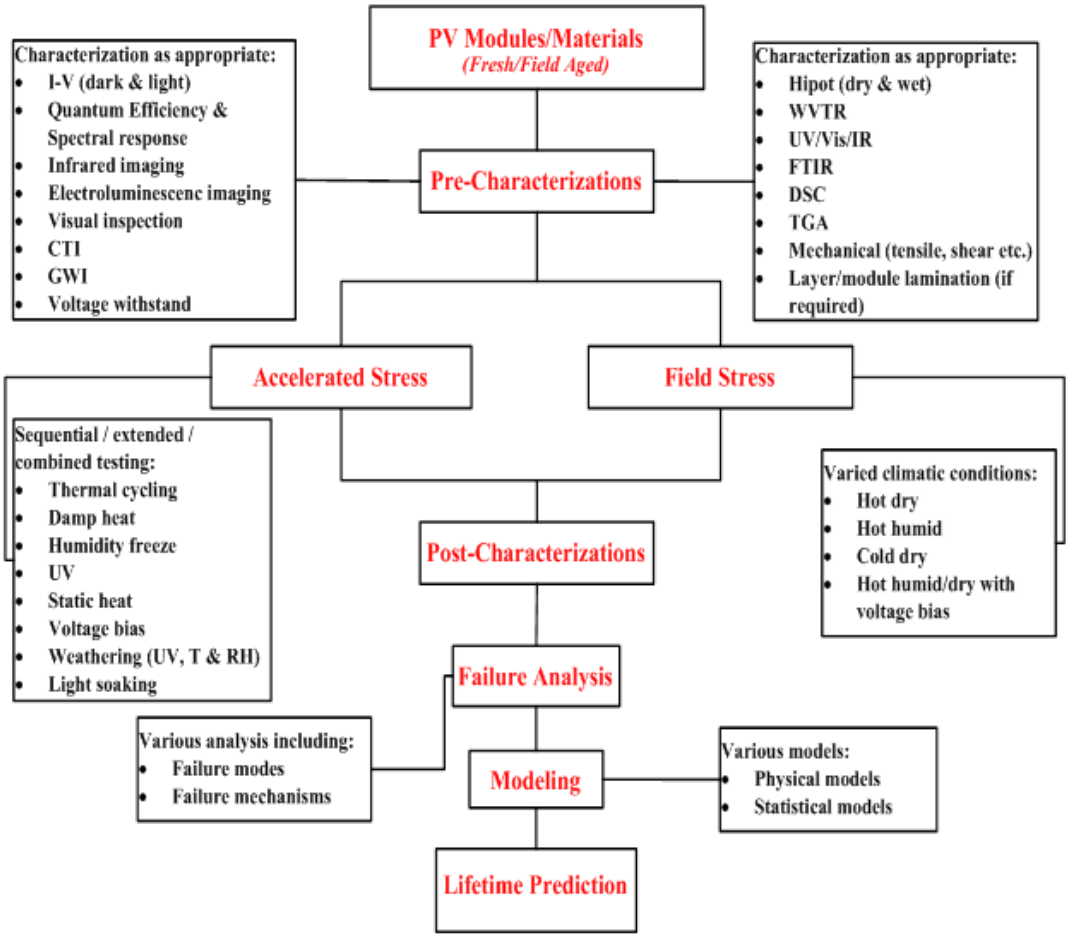
			IEC 61215 on Steroids									Weather	New Tests						
	Protocol Name	IEC 61215	Holistic OA	Thresher Test	Reliability Demo Test	Durability initiative	Test to Failure	Long-term Sequential Testing	Atlas 25	Irradiation/ Thermal	Accelerated TC test	Vibration	ISAAC for Mounting	HV Bias Testing
	Contact person		Cunningham	Funcell	Meydbray	Meakin	Hacke	Mani	Scott	Hirota	Tanahashi	Schueneman	Friesen	Dhere
Thermal	Thermal Cycle	B2, C1	B3, C1	A1*	A1, E2	C3, D3, F1	B1	A6, B6			A2*, B2*			
	Humidity Freeze	B3	B4	B2	C1, E3	C4, D4		A9, B9			A1**			
	Damp Heat	D1, E1	D1, E1	C1*	B1	B1		A1, B1			B1**			
	Extended Damp Heat		D2, E2	C2, C3, C4, C5	B2, B3	B3	A2, A3, A4...A15, C3, C5...C15*	A2, A3, A4, A5	C3 condensing					
	Extended TC		C2	A2, A3, A4, A5, A6	A2, A3	F2, F3	B2, B3, B4...B15, C2, C4...C14	A7, A8, B7, B8	C4*					
	Extended Humidity Freeze			B3, B4, B5	C2, C3			A10, A11, A12, B10, B11, B12	C4*					
	Bybass Diode Test	A2	2A		F4, G4			A13, B13						
Summary	Expected duration	2 months	4 months	6 months	6 months	6 months	> 1 yr	1 yr	1 year		max. 3 month			
	Goal	Qualify design	Extended 61215	Compare by tracking changes	Comprehensive	Durability assessment	Comparative test to failure	Sequential	Simulate weather stress	Add light to uncover failures	Extend the limits of the TC	Vibration	Snow and wind on mounted module	
	General philosophy*	Baseline	1	1	1	1	1, 4, 6	1	2	4	1, 2	5	5	4, 5
	Change stress duration or level?	N/A	Duration	Duration	Duration	Duration	Duration	Duration	N/A	Combine	Level	New test	New test	New test
	Field test data ?		Yes			1 yr +		3 yr+ (optional)	Yes					
	Allow for different climate zones?							Optional field test in different climate zones	Yes					
	Measurements other than 61215?	N/A	EL	EL	IR, EL, diode	EL, IR, DIV		IR, EL (optional)	?	?	EI***, IR, Impedance	?	EL	?
	Number of measurements			up to 6		up to 6	up to 15	3-5 each						
	*Philosophy: 1. Comparative, Rank ordering 2. Simulation of stressful weather 3. Service life prediction 4. Identify failure modes (HAST) 5. Looks at specific failure modes 6. Test to failure?			*Test frequently			*DH includes system V		*Exposure conditions vary		*Raise Upper T level or Ramp rate **A1, B1 optional ***Quantify cell cracks	*Vibrational test	* 9000 Pascal **35 mm	

Definition of Terms used in the Previous Table (Summary of Comparative of Testing Programs)

- Each leg of the test is given a letter
- The steps in each leg are numbers, so look for A1, A2, etc. for the first leg and B1, B2 for the second leg
- This summary is simplified and doesn't describe the number of modules in each leg, the length of each step, nor the characterization that is done between each step
- Blue shading indicates that the step is fairly similar to IEC 61215; Yellow indicates that the test goes beyond IEC 61215 or differs in some other way
- The test methods are separted into 3 classes:
  1. IEC 61215 on steroids: Like IEC 61215, but with extended time or somehow slightly more severe
  2. One of the tests is very different from IEC 61215, but attempts to mimic the weather in order to identify all weathering issues
  3. Individual tests are proposed as add ons or modification to a more comprehensive test procedure
- Across the bottom, some higher level attributes are described briefly.

APPENDIX D: EQUIPMENT AND EXPERTISE NEEDED FOR PV MODULE RELIABILITY RESEARCH PROGRAM—AN EXAMPLE

PV Module Lifetime Research: A Potential Approach



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VALIDATING PHOTOVOLTAIC MODULE DURABILITY TESTS

Prepared by

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June 2013

Solar America Board for Codes and Standards
www.solarabcs.org

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EXECUTIVE SUMMARY

The reliability of photovoltaic (PV) modules for their intended service lifetime, currently based on a 20- to 25-year minimum, is a key requirement of financial stakeholders. The current generally accepted minimum testing and performance requirements are described in the design qualification and safety tests of the International Electrotechnical Commission (IEC). Although these standardized requirements have been largely successful in keeping poor quality modules out of the marketplace, field failures of installed modules still occur. These may range from catastrophic failures occurring early in a module's life to long-term degradation and power loss or safety concerns later in the module's life.

It is widely recognized that the existing basic qualification tests are not lifetime reliability assurance tests, which is what the industry needs. Therefore, considerable research into module degradation and failure modes has been and continues to be performed by manufacturers, national laboratories, private and public research institutions, and academia. These efforts have greatly contributed to the present scientific understanding of module degradation and failure mechanisms, and the industry continues to learn new things as it gains more and longer field experience with current module technologies and designs.

This increased knowledge has led the ongoing industry efforts to develop and standardize more comprehensive tests that move beyond basic qualification testing to tests that can better predict long-term reliability or better compare and rate different modules for various attributes. Over the past several years, this effort has gained considerable momentum, and PV module and system reliability issues are now the subject of numerous specialized symposia and workshops and a key topic at PV and solar energy technical and investment conferences.

These efforts currently fall into three major categories. The first can be described as "IEC 61215 on steroids," consisting of protocols that are derivatives of the current IEC 61215 tests, either by extending the durations or combining the tests in new sequences or cycles. The second category is "weather" testing—test programs that primarily use weather durability testing principles and methods. The third is "new tests," which are either add-ons or modifications to a more comprehensive test protocol. Additionally, efforts are underway to establish PV materials tests. The key activities in these areas are summarized in this report.

Accelerated testing has been ongoing for about 35 years, leading to the current IEC qualification standards. However, there has not been a systematic effort to identify short- and long-term degradation and failure modes and to use that information to develop and validate a comprehensive testing methodology. Further, no definitive models exist that fully link test results with long-term performance—a service life prediction model, for example. The final missing standards piece is a quality assurance program to assure stakeholders that current production models are of the same or better quality as those passing the qualification tests.

This report details a comprehensive long-term multi-step effort required to develop and validate both current and new tests and a roadmap to develop a service life prediction methodology. Finally, the report recommends an interim solution using the current standards process.

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Allen Zielnik has degrees in electronics engineering and analytical chemistry. For the first 19 years of his career, he was involved with various scientific instrument companies dealing with chemical and physical methods of analysis, specializing in polymer molecular weight determination and separations science. The past 19 years, he has been with Atlas Material Testing Technology, in Ametek's Measurement and Calibration Technology division. He serves as Senior Consultant—Weathering Science in Atlas' Global Consulting group as well as a senior member of Atlas' Solar Energy Competence Center. He has been involved with supplying durability test equipment to the PV industry since 1994 and has authored more than 100 articles on materials weather durability and testing technology.

Solar America Board for Codes and Standards

The Solar America Board for Codes and Standards (Solar ABCs) provides an effective venue for all solar stakeholders. A collaboration of experts formally gathers and prioritizes input from groups such as policy makers, manufacturers, installers, and large- and small-scale consumers to make balanced recommendations to codes and standards organizations for existing and new solar technologies. The U.S. Department of Energy funds Solar ABCs as part of its commitment to facilitate widespread adoption of safe, reliable, and cost-effective solar technologies.

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Acknowledgments

The author wishes to sincerely thank the following individuals who have provided key guidance and information for this report: David Burns (3M Company), Zach Campeau (SunPower), David Dumbleton (Atlas Material Testing Technology), Christopher Flueckiger (Underwriter's Laboratories), Ryan Gaston (Dow Solar), Jenifer Granata (Sandia National Laboratory), Peter Hacke (National Renewable Energy Laboratory [NREL]), George Kelly (BP Solar), Sarah Kurtz (NREL), Eric Romano (DuPont), Andy Rosenthal (New Mexico State University), Kurt Scott (Atlas Material Testing Technology), Mani TamizhMani (TÜV Rheinland), Larry Sherwood (Solar ABCs), and John Wohlgemuth (NREL).

TABLE OF CONTENTS

DISCLAIMER 2
EXECUTIVE SUMMARY 3
AUTHOR BIOGRAPHIES 4
SOLAR AMERICAN BOARD FOR CODES AND STANDARDS 4
ACKNOWLEDGMENT 4
INTRODUCTION 6
WHAT DEFINES "FAILURE"? 9
SERVICE LIFE EXPECTATIONS 10
COMMON PHOTOVOLTAIC FAILURE MODES 11
THE PATH TO IEC 61215/61646 12
BEYOND CURRENT IEC QUALIFICATION TESTING 20
DURABILITY AND RELIABILITY TESTING CONCEPTS 38
TESTING IN OTHER INDUSTRIES 43
SERVICE LIFE ASSESSMENT AND SERVICE LIFE PREDICTION 46
TEST METHOD VALIDATION 48
RECOMMENDATIONS FOR TEST VALIDATION 51
SUMMARY 53
ACRONYMS 57
REFERENCES 58

Introduction

The need for durability and reliability in photovoltaic (PV) modules and systems is well recognized. At the module level, solar panels must be both durable and reliable for many reasons. The term "bankability" is often used to describe a number of aggregate properties, including:

- power degradation over product lifetime that affects revenue generation;
- engineering, procurement, and construction and operations and maintenance considerations that affects overall system cost; and
- safety of life and property that affects insurance costs and regulatory compliance.

A relative comparison of good versus poorer performing systems is provided by Kurtz (Kurtz, 2009) in Figure 1.

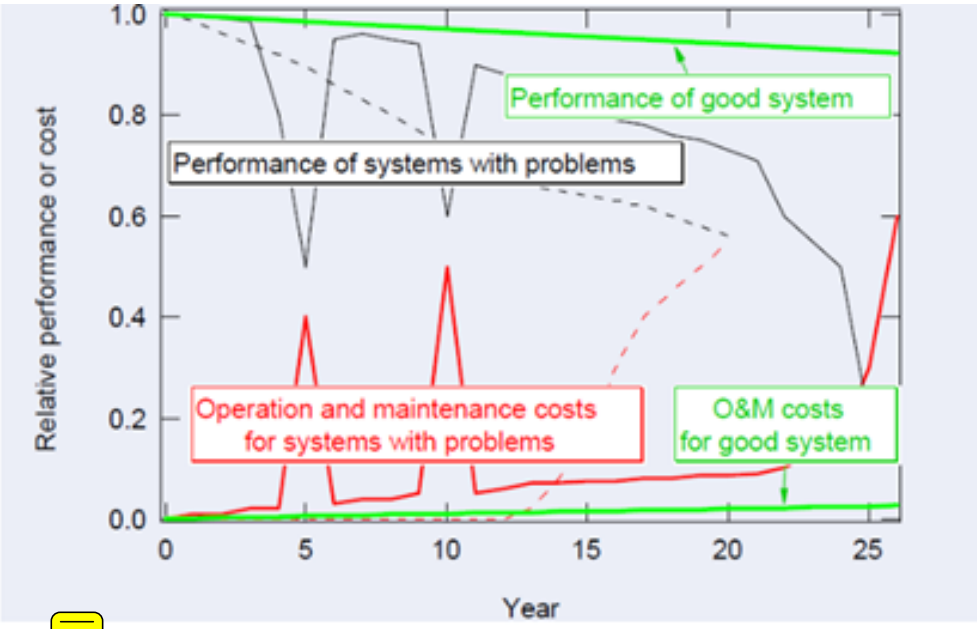

Figure 1: Comparison of "good" systems vs. those with problems (Kurtz, 2009).

There are documented cases of PV installations ten, twenty, or more years old that are performing well with low failure rates. There are also, however, reported instances of arrays requiring high levels of module replacement within several years of installation (Carus, 2013; Hibberd, 2011; Kato, 2012; Kuhn, 2011; Mayer &Meydbray, 2012; Wang, 2012). Although some of these are likely limited to specific module manufacturers or models, or may be related to installation or other issues, the PV industry needs a way to more accurately assess fielded module durability. Therefore, the term "module failure" clearly depends on many factors, including:

- device technology, materials, design, and manufacturing;
- end use climate; and
- transportation, installation, and maintenance.

It is tempting to rely on overall past industry success, but there are several factors that work against this:

- Many current module designs, especially those manufactured after about 2004, are substantially different from earlier designs in materials and construction (Bradley, 2013). These include thinner silicon (Si) cells and encapsulant layers, frameless designs, and alternative backsheet materials and cell interconnects. It is not clear whether these changes have affected durability and reliability when compared to earlier designs.
- The use of lower cost materials and manufacturing methods in new modules may negatively impact quality.
- Many new, often low-cost, manufacturers with no or limited prior history or experience are entering the marketplace.

Manufacturer warranties may be of limited value if the module manufacturer is no longer in business. Even with third party insurance, replacing modules often requires reconfiguring arrays and incurring additional costs if identical replacement modules (power rating, electrical characteristics, and physical size) are no longer available.

Meeting International Electrotechnical Commission (IEC) design type qualification (IEC, 2005; IEC, 2008) is not a guarantee of either long-term performance or service lifetime. Although these tests have proven effective at weeding out weak designs, many type-approved modules still fail in service. It is now widely, though not universally, recognized that the IEC qualification standards do not currently go far enough to demonstrate long-term durability and reliability, or to predict service life (Wohlgemuth, 2012). Further, the IEC tests address design qualification, not whether the module manufacturer has an adequate quality assurance system to consistently produce modules that will perform like qualified modules, as described by Mikonowicz (Mikonowicz, 2011).

This paper explains basic concepts and principles of durability and reliability testing, service life prediction methodology, and test validation. It summarizes the development rationale leading to the current IEC module qualification standards and what is generally believed to be their strengths and weaknesses. Further, it summarizes the main known or suspected failure modes of PV modules as well as currently proposed alternative test protocols and highlights ongoing industry and standards activities. The report also includes a gap analysis on these items and a process framework for validating these various tests.

The focus here is primarily on mono- and multi-crystalline silicon terrestrial flat-plate collectors, because most installed and currently produced modules fall into these categories and the outlook is for this to continue into the foreseeable future. This encompasses a broad range of cell and interconnect technologies, materials, and module designs.

The fundamental principles described here also apply to thin films (TF). However, due to the small number of manufacturers, the small size of the currently installed base, and the relative time in service, less is known regarding TF degradation and failure mechanisms. Where possible, specific TF issues will be noted.

These principles also generally apply to other PV technologies such as organic PV and dye-sensitized solar cells, although the degradation mechanisms are often substantially different from Si. Further, general principles apply to various exterior building-integrated PV products although these usually have their own specific issues as both a functional building element and a PV device.

In addition, the use of onboard active electronic direct current/alternating current (DC/AC) microinverters (AC modules) or DC/DC power optimizers, some with digital communications capability, is growing rapidly. Originally externally attached, these electronics are increasingly being incorporated directly into the module laminate package. The use of in-module laminated bypass diodes has also re-emerged in some designs. The specific effects of these devices on module durability and performance, the effects of environmental and service use stresses on these components, and the possible need for different testing methodologies are just beginning to be investigated. At present, these are not treated differently from traditional module designs in terms of testing standards.

Finally, for testing and qualification purposes, a "line of demarcation" must be drawn between factors that affect standalone modules (including in test) and those involved with interconnected modules in strings and arrays. Also, the effects of various electrical loads may have an impact, but mostly are not considered as factors in current module tests.

WHAT DEFINES "FAILURE"?

The most commonly used description of what constitutes PV module "failure" involves three independent parameters:

- catastrophic failure (no output),
- power loss beyond a defined limit, and
- safety of life or property issues.

From the user's perspective, other factors not affecting performance—aesthetic issues, for example—may also be a consideration. The first two parameters noted above primarily involve durability or reliability issues intrinsic to the module design, materials, or manufacturing, or resulting from the effects of environmental exposure or other extrinsic in-service conditions. These failures may be catastrophic, immediately resulting in a dead module, or may degrade with time in some manner that affects power output beyond an expected level. The third failure type involves safety risks that cause the module to be taken out of service prematurely.

At present, IEC and related PV design type qualification and safety tests are performed on modules that have only been stressed through accelerated tests. There are no retest requirements for field-aged modules.

SERVICE LIFE EXPECTATIONS

It seems logical to expect PV service life to be at least partially dependent upon the severity of the climate where the module is used, because some degradation modes can be related to specific climate stresses. However, most current test standards do not test or tie module performance to different climates. Also, current qualification and safety standards do not specify any module durability, reliability, or performance minimums beyond the initial qualifications. In addition, they do not specify any minimum required service life.

Manufacturers determine module warranties. Due to market competition, most module warranties fall within a general range, typically based on two independent parameters:

- **Repair, replace, or refund warranties** cover defects in materials or workmanship, and presently have durations of 5 to 10 years.
- **Lost power replacement warranties** typically offer remedies such as supplying additional modules to supplement for the power loss, repairing or replacing modules, or providing monetary compensation. Typical values are minimum peak power of more than 90% at 10 to 12 years, and more than 80% up to 20 to 25 years, although some manufacturers go beyond this. Both step-wise and straight line depreciation methods are used, depending on the manufacturer. A warranty may also be provided by a third-party insurer as a hedge against manufacturer insolvency.

Terms and conditions of warranties are manufacturer-specific. Minimum power performance is typically based on the minimum power rating, less tolerances, of the nameplate rating. These ratings are under laboratory standard test conditions and are not necessarily indicative of output performance at installation or over time. The general industry expectation of service life most commonly quoted is a minimum of 25 years power generation at more than 80%, although "useable" life expectations by users and investors can exceed 40 to 50 years or more, even at lower power levels.

COMMON PHOTOVOLTAIC FAILURE MODES

Many failure modes have been identified in PV modules over the years. In 1977, the U.S. Department of Energy (DOE) established the Solar Energy Research Institute (SERI) in Golden, Colorado, subsequently renaming it the National Renewable Energy Laboratory (NREL) in 1991. NREL maintains a running summary of quality and reliability issues by PV technology (Bosco, 2010). Key findings are included in Figure 2.

Reliability Concerns Associated with Application of PV Technologies in Systems

	Known and Anticipated Failure Modes & Degradation Mechanisms	Priority/Prob. of Success / Role for Labs (High-Medium-Low)	Diagnostic Technique / Qual Test (e.g., chamber tests, HVTB)	Comment
General	Corrosion leading to loss of grounding	H/H/H		
	Quick connector reliability	H/H/L		
	Improper installation leading to loss of grounding	H/H/L		
	Delamination	H/M/M		This is especially a problem for flexible packages
	Glass breakage	M/H/L		For products using glass
	Bypass diode failure	M/H/L		
	Inverter reliability	M/H/M		
Wafer Si	Poor solder joints between string ribbons and wires inside junction boxes – arcing	H/H/H		
	Cracked cells (caused by bonding of conductors, strain etc.)	H/M/H	Electroluminescence can detect cracks.[1]	Cracking may become worse for thinner wafers
	Increased series resistance from solder joint or gridline interface failure	H/M/M		This is not new, but continues to be a quality assurance issue
	Reduced adhesion strength that increases corrosion and/or delamination	M/M/M		
	Slow degradation of I_{sc}	M/M/M		Mechanisms are not fully understood
	Fatigue of ribbon due to thermal cycling	H/H/L		Not new, but continues to be an issue
	Junction box failure	H/M/L		
	Busbar adhesion, electrical contact, etc.	M/M/M		
	Glass edge damage of frameless modules (installation, handling, etc.)	M/M/L		Frameless construction is infrequently used today for Si.
	Light-induced cell degradation	M/M/L		
	Effect of glass on encapsulant durability	M/M/L		Problems may return because of Ce being removed from the glass
	Effect of glass on module performance	M/M/L		
	Front surface soiling	L/M/L		
	Stress breakage in glass-glass laminates	L/H/L		Glass-glass laminates are almost never used because of added weight.
Film Si	See items listed in "General" section			
	Electrochemical corrosion of SnO_2:F	M/M/L	Light soaking; Voltage biased damp heat[2]	
	Initial light degradation (a-Si)	L/L/L	Light soaking	
	Annealing instabilities (a-Si)	L/L/L	Light soaking	
CdTe	Cell layer integrity – backcontact stability	H/H/H		
	Cell layer integrity – interlayer adhesion and delamination; Electrochemical corrosion of SnO_2:F	L/L/M	Voltage biased damp heat[2]	
	Fill-factor loss (increased series resistance and/or recombination)	H/M/H	Cell + Module Light soaking; Damp Heat	Screen at cell initially; then module
	Busbar failure - mechanical (adhesion) and electrical	H/H/M	IR Camera; Hot/humid vs. damp heat	Thermal stress[3]
	Shunt hot spots at scribe lines before and after stress	H/M/M	IR Camera; Hot/humid vs. damp heat	
	Weak diodes, hot spots, nonuniformities before and after stress	H/M/H	IR Camera; Hot/humid vs. damp heat	
CIS	Cell layer integrity – contact stability	H/H/H		Mo backcontact (all), the front contact is only a problem when the module is assembled from discrete cells
	Cell layer integrity – interlayer adhesion	M/H/M		
	Fill-factor loss (increased series resistance and/or recombination)	H/M/H	Cell + Module Light soaking; Damp Heat	Screen at cell initially; then module
	Busbar failure – mechanical (adhesion) and electrical	M/H/M	IR Camera; Hot/humid vs. damp heat	
	Notable sensitivity of TCO to moisture	H/M/H	Damp heat exposure	
	Moisture ingress failure of package	H/M/H	Hot/humid vs. damp heat	Flexible roofing products
	Cell–to-cell interconnect (discrete cells)	H/M/H	IR Camera; Hot/humid vs. damp heat	Flexible roofing products; this is a problem when discrete devices are interconnected into modules
	Notable sensitivity of TCO to moisture; need to pass damp heat test (non-shingle specific)	H/M/M	Damp heat exposure	
	Shunt hot spots at scribe lines before and after stress	H/M/M	IR Camera; Hot/humid vs. damp heat	
	Weak diodes, hot spots, nonuniformities before and after stress	H/M/H	IR Camera; Hot/humid vs. damp heat	
	Edge shunting	M/H/M		Discrete Cell – Flexible roofing products

Figure 2. Common PV failure modes by technology as reported by NREL (Bosco, 2010). Note that TCO = transparent conducting oxide, I_{sc} = short circuit current, a-Si = amorphous silicon, Ce = cerium, and IR = infrared.

Although these are the bulk of the known issues, the root causes of a particular failure may not be completely known. It is possible for a given failure to have multiple initiating modes, or to result from a combination of simultaneous or sequential degradation or failure mechanisms that current tests may not adequately detect. Certainly, new failure modes may surface with future module designs and materials.

THE PATH TO IEC 61215/61646

IEC 61215 and IEC 61646 design type qualification tests are the currently accepted minimum testing requirements in most of the world, although they are not mandated in the United States. They specify certain tests, including various module environmental exposure tests, as a minimum qualification for acceptance. They do not purport to be performance, durability, or reliability indicators beyond initial qualification, despite being often mistaken for or portrayed as such.

Nonetheless, because they serve as the de facto basis for much of the current and proposed durability/reliability testing methodologies, it is important to examine their key tests and the process leading to their development. With this understanding, it is easier to identify their advantages and disadvantages relative to what is being proposed to address long-term PV durability and reliability issues, tests, and standards.

NREL's Carl Osterwald and Thomas McMahon (Osterwald & McMahon, 2009) published a landmark review, *History of Accelerated and Qualification Testing of Terrestrial Photovoltaic Modules: A Literature Review*, spanning the 30+ year period from 1975 to 2008. The reader is referred to this document and the 170 references cited for greater detail than can be described here.

Since the 1970s, there have been a number of PV qualification test sequences developed by various entities, each successively building on the knowledge gained in an attempt to detect the presence of known failure or degradation modes in the intended environments. These have evolved into a series of tests paths, successful completion of which at least implies that a module will last a minimum number of years. That is, these test paths should avoid out-of-box or early service failure.

Starting in 1975, the Flat-Plate Solar Array project was begun by the Energy Research and Development Administration, which in 1977 was integrated into the U.S. Department of Energy. Under this program, the National Aeronautics and Space Administration's (NASA's) Jet Propulsion Laboratory (JPL) organized a series of purchases of PV modules from manufacturers designated as JPL "Block Buys I through V." All modules were crystalline silicon. Based on field experience and failure analysis of degraded modules, each of the five block buys generally placed increasingly stringent accelerated stress tests on the modules through additional tests, altered test parameters, and varied test durations to reach the current IEC 61215 qualification tests.

A summary of the tests used in the block buy program (Ross, 1982-1983) is shown in Figure 3.

Test	Block I	Block II	Block III	Block IV	Block V
Thermal Cycle	100 -40 to +90°C	50 -40 to +90°C	50 -40 to +90°C	50 -40 to +90°C	200 -40 to +90°C
Humidity Cycle	70°C, 90%RH 68 hours	5 -23 to 40°C 95%RH	5 -23 to 40°C 95%RH	5 -23 to 40°C 95%RH	10 -40 to +85°C 85%RH
Mechanical Loading Cycle		100 2400Pa	100 2400Pa	10000 2400Pa	10000 2400Pa
Wind Resistance				X UL997	X UL997
Hail Impact				9 impacts ¾", 45mph	10 impacts 1", 52mph
High Potential		<15µA 1500	<50µA 1500V	<50µA 1500V	<50µA 2xVs+1000V

Figure 3. Summary of key JPL Block qualification tests. Note that Block I used 100 thermal cycles, Blocks II-IV used 50 cycles, and Block V increased to 200 cycles (Ross, 1982-1983). Note that RH = relative humidity and µA = microamperes.

As Wohlgemuth explains (Wohlgemuth, 2011):

- Block I tests were based on NASA tests used on space arrays. Thermal cycle extremes were selected as -40 and +90°C based on estimates of worst case terrestrial environmental conditions. Humidity testing for space arrays was short duration due to the limited pre-launch exposure time. Block I exhibited many early failures due to cracked cells; one cracked cell resulted in total power loss due to the designs. Non-glass superstrate modules exhibited significant soiling and delamination, usually due to solar ultraviolet (UV) exposure.
- Block II added 100 mechanical load cycles, likely influenced by NASA experience with space launch damage. It added an electrical high potential (Hipot) test to ensure electrical insulation, and reduced the thermal cycles from 100 to 50, although the rationale for the reduction is unknown. The humidity test was changed from a constant level to 5 cycles of -23°C to 40°C.
- Block III changed the Hipot failure level as module size increased. Block II and III modules were used in some larger systems, many in desert environments, and exhibited new failure modes. Modules that passed 50 thermal cycles failed in the desert due to broken cells or interconnects, resulting in total power loss. Most new modules used glass superstrates, reducing thermal expansion and contraction.
- Block IV increased the mechanical load cycles and added hail impact, because hail was found to cause broken cells and superstrate glass breakage unless tempered glass was used.
- Some modules built without bypass diodes exhibited hot-spot failures, so a hot-spot test was added in Block V, and the thermal cycles were increased to 200. The humidity freeze test was also increased from five to ten cycles between Blocks IV and V. As Whipple (Whipple, 1993) described, this appears to have helped dramatically reduce ten-year failure rates.
- A sixth block buy was scheduled but never implemented due to funding cuts. Additions planned for 1985 included bypass diode, UV exposure, and damp heat (85°C/85% relative humidity [RH]) tests.

Wohlgemuth further details the activity leading to the current second editions of IEC 61215 and 62646 (Wohlgemuth, 2012). In Europe, the European Solar Test Installation, now part of the European Commission's (EC's) Joint Research Centre (JRC) in Ispra, Italy, simultaneously worked on a PV qualification standard at the time of the JPL work. European Standards 501 and 502 had some similarities to the Block V tests with the addition of a UV test, outdoor exposure, and a reduction in the thermal cycle high temperature from 90°C to 85°C. EU 503 was a draft of IEC 61215 before it became official.

- Block VI was the basis for IEC 61215. Several tests from Block VI were not included in 61215—the dynamic mechanical load test defined in Block V because it was unsuitable for large modules, and the bypass diode thermal test because the international community did not consider it adequately developed.

- SERI work on TF modules, mostly amorphous silicon (a-Si), led to an interim qualification test (IQT). A significant issue was high leakage current resulting from inadequate edge isolation of the transparent conducting oxide (TCO) on the glass, and a wet insulation resistance test was added as well as ground continuity and cut susceptibility tests from UL 1703 and the Block VI bypass diode test. The IQT led to IEEE 1262. It was a hybrid of elements of IEC 61215 and the IQT, addressing light-induced degradation (LID) in a-Si. IEEE 1262 subsequently led to the development of IEC 61646 and was then withdrawn as being redundant. Other changes in the IQT from IEC 61215 include the addition of wet leakage current, light soak and anneal cycles, and added maximum power output under standard test conditions after a final light soak as a pass/fail criteria.
- IEC 61215 Edition 2 (2005) eliminated the twist test, added the IEC 61646 wet leakage current test, added the IEEE 1262 bypass diode thermal test, and changed the pass criteria for dielectric withstand and wet leakage current test to be dependent on the test module area. It added the requirement to run peak power current through the module during the 200 thermal cycles to evaluate field observed solder bond failures, and clearly labeled the UV test as only a preconditioning test.
- IEC 61646 Edition 2 (2008), in an attempt to adapt to non-a-Si thin film technologies, modified the pass/fail criteria by requiring modules meet the rated power after all tests have been completed and the modules have been light-soak stabilized, and to eliminate meeting a power criterion before and after each test. It also eliminated the twist test, made the dielectric withstand and wet leakage current tests dependent on test module area, rewrote the hot-spot test, added the bypass diode thermal test, and relabeled the UV tests as only a preconditioning test.

Description of Key IEC Durability-Related Tests

The key accelerated stress tests for PV modules (Wohlgemuth, 2011) are detailed in Figure 4.

Accelerated Stress Test	Failure Mode	Technology
Thermal Cycles	Broken interconnect	c-Si
	Broken cells	c-Si
	Electrical bond failure	All
	Junction box adhesion	All
	Module open circuit—potential for arcing	All
Damp Heat	Corrosion	All
	Delamination	All
	Encapsulantloss of adhesion &elasticity	All
	Junction box adhesion	All
	Electrochemical corrosion of TCO	TF
	Inadequate edge deletion	TF
Humidity Freeze	Delamination	All
	Junction box adhesion	All
	Inadequate edge deletion	TF
UV Test	Delamination	All
	Encapsulant loss of adhesion & elasticity	All
	Encapsulant and backsheet discoloration	All
	Ground fault due to backsheet degradation	All
Static Mechanical Load	Structural failures	All
	Broken glass	c-Si & TF
	Broken interconnect ribbons	All
	Broken cells	c-Si
	Electrical bond failures	All
Dynamic Mechanical Load	Broken glass	c-Si & TF
	Broken interconnect ribbons	All
	Broken cells	c-Si
	Electrical bond failures	All
Hail Test	Broken glass	c-Si & TF
	Broken cells	c-Si
Bypass Diode Thermal Test	Bypass diode failures	All
	Overheating of diode causing degradation ofencapsulants, backsheet, or junction box	All
Salt Spray	Corrosion due to salt water or salt mist	All
	Corrosion due to salt used for snow and ice removal	All

Figure 4: Accelerated stress tests for common PV module failures (Wohlgemuth, 2011). Note that TF = thin film, TCO = transparent conducting oxide, and c-Si =

The IEC 61215 and 61646 qualification tests now include the following stress tests (Wohlgemuth, 2011):

- damp heat exposure at 85°C and 85% RH for 1,000 hours;
- 200 thermal cycles from -40°C to +85°C with peak power current flow above room temperature;
- a combined leg of UV preconditioning (15 kWh/m^2), 50 ther cycles from -40°C to +85°C, and humidity freeze (HF) cycles from +85°C, 85% RH to -40°C;

- wet leakage current test at the rated system voltage;
- mechanical load test of three cycles of 2,400 Pascals uniform load, applied for 1 hour to front and back surfaces in turn;
- hail test with 25mm diameter ice ball @ 23 m/sec directed at 11 impact locations;
- a bypass diode thermal test, with one hour at short circuit current at 75°C and one hour at 1.25X short circuit current at 75°C; and
- hot-spot test with 3 lowest shunt resistance cells subjected to one-hour exposure to 1,000 W/m^2 irradiance in worst-case hot-spot condition and highest shunt cell subjected to five hours of 1,000 W/m^2 irradiance in worst-case hot-spot condition.

Based on field experience and failure analysis of degraded modules, each of the five block buys placed increasingly stringent accelerated stress tests on the modules through additional tests, altered test parameters, and varied test durations to reach the current IEC 61215 qualification test sequence in Figure 5.

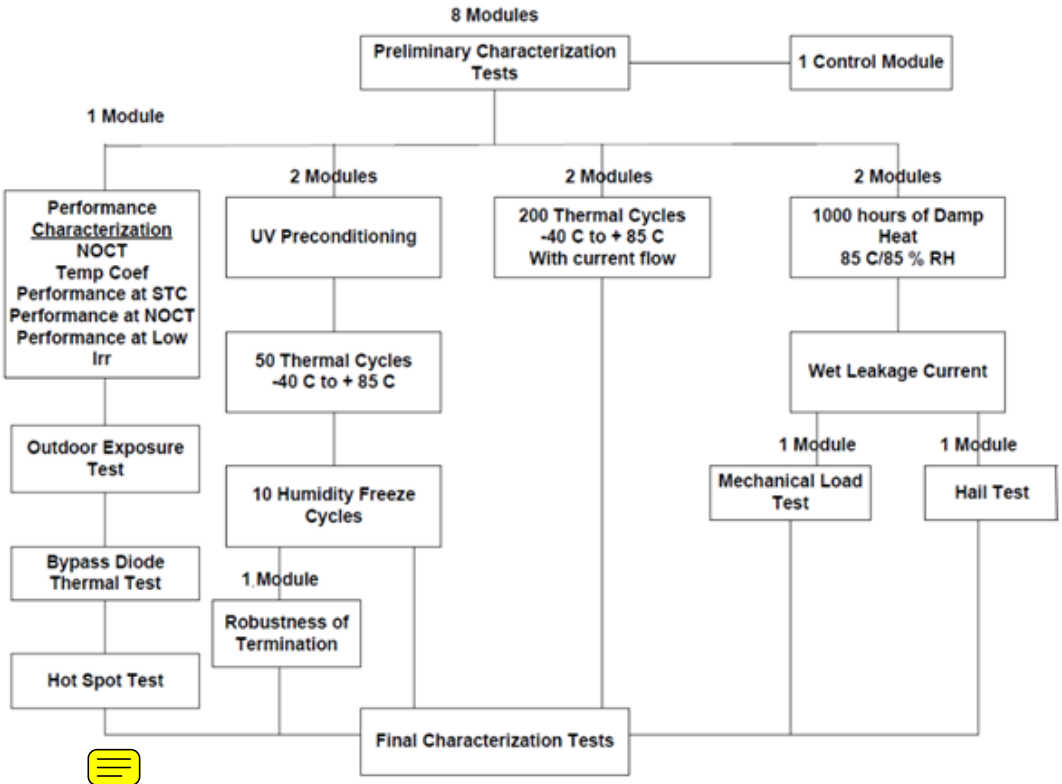

Figure 5. IEC 6125 2nd edition qualification test sequence (Wohlgemuth, 2012).

In IEC qualification testing, the types and ratios of failures seen prior to module changes circa 2004-2005 and those manufactured since has shifted somewhat (Figure 6) (TamizhMani, 2010). A significant portion of this change can be attributed to several factors. First, there was a large influx of new module manufacturers trying to quickly introduce products into the market during this timeframe. As Wohlgemuth notes (Wohlgemuth, 2012),the qualification tests became more stringent at that time. Adding the wet Hipot test after the damp heat test contributed to many of the new damp heat failures for monocrystalline silicon (c-Si) in the 2005 to 2007 period. Adding current flow also increased the thermal cycling and diode failures in this interval.

However, this does raise the question of whether current module designs and materials may also now perform somewhat differently either in accelerated testing or in actual long-term service from earlier models. For example, as noted by Bradley (Bradley, 2013), Si wafer thickness has decreased from 300 to 350 microns or more to about 150 to 180 microns. When a cell breaks, it starts to get hot, which can accelerate the degradation of polymers such as encapsulants. If the susceptibility of current modules to long-term environmental and service use stresses has changed, the appropriateness of some current or extended tests based on prior materials and designs may be questioned. However, it is not completely clear whether this is actually the case.

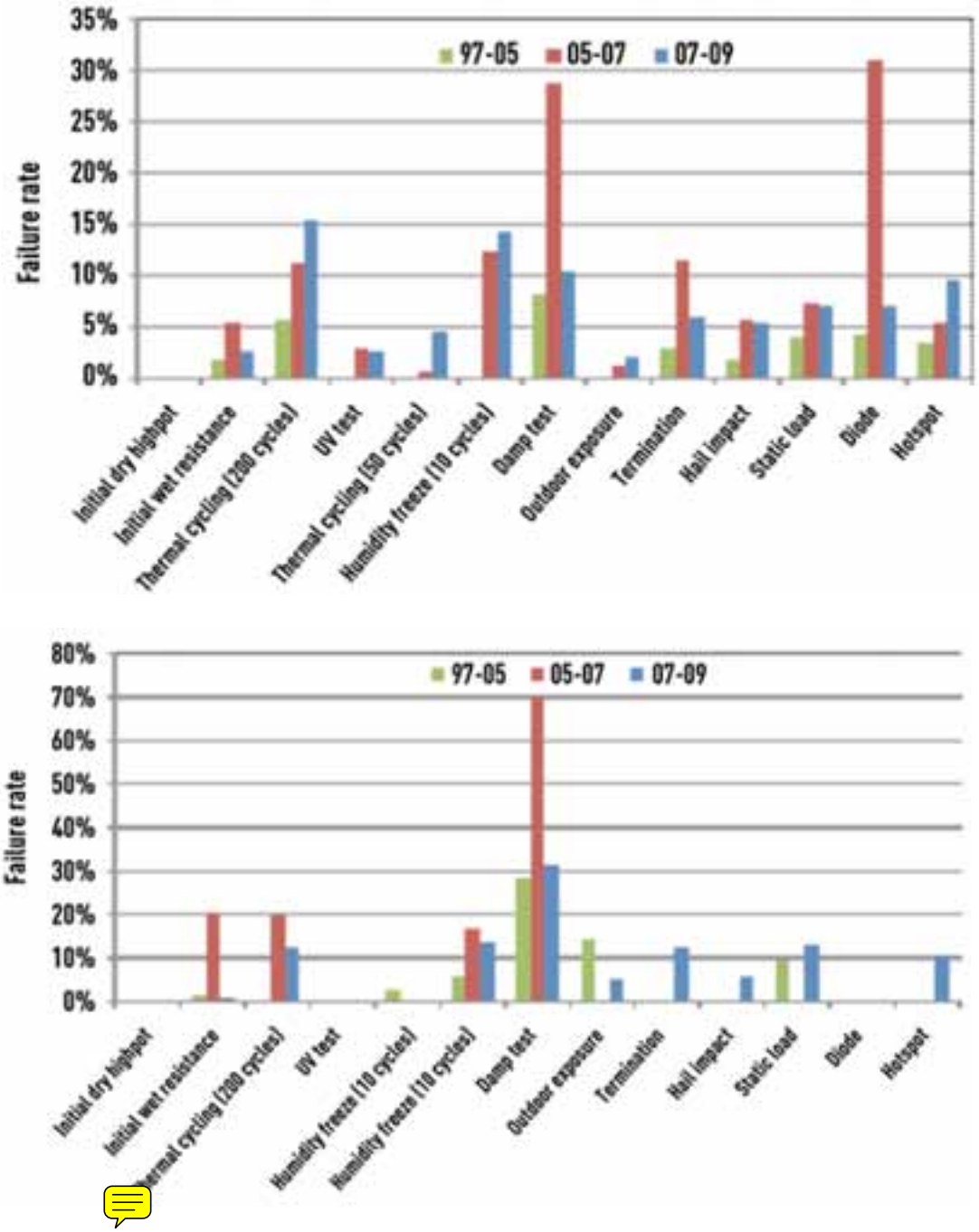

Figure 6: IEC qualification test failure rates of c-Si (top) and TF (bottom) modules for periods 1997 to 2005, 2005 to 2007, and 2007 to 2009 (TamizhMani, 2010). Note that UV = ultraviolet.

Note that most of the IEC qualification tests are primarily directed at the module package—the principal source of module problems—and the interconnections between components. Tests such as the thermal cycling and damp heat have their origins in the industrial and military electronics and semiconductor device industry, in which the direct outdoor exposure of the semiconductor or packaging to the elements, including sunlight, is relatively uncommon. It is notable that during most of the IEC environmental tests, the module does not produce electricity from light exposure, which is the purpose of the device. It is known that failure mechanisms such as LID can be attributed to module operation in sunlight (Sopori et al., 2012). Of the failure mechanisms identified in Figure 2, it is not clear what fraction may be directly caused or influenced by sunlight exposure.

In an extensive PV systems survey, Rosenthal and Thomas (Rosenthal, Thomas, & Durand, 1993) found that failure rates in pre-Block V modules decreased significantly from 45% to less than 0.1% for Block V. Degradation rates for 10 selected systems were found to be larger than 1% per year, although c-Si systems deployed in Florida had degradation rates well below that.

Programs similar to the above were conducted during that time in Europe, Australia, and Japan by other organizations. Jordan and Kurtz (Jordan & Kurtz, 2012) have conducted a systematic analysis of nearly 2,000 PV degradation rates found in the literature over a span of 40 years. Jordan reports that 78% of all data reported a degradation rate of less than 1%/year, and often significantly less than that. Older TF technologies were statistically closer to 1%/year, but more recently produced TF modules had significantly reduced degradation rates. A value closer to less than 0.5%/year is necessary to meet 25-year commercial warranties. Also, only a few of the module types fielded had reached their 25-year anniversary.

Currently, most power degradation models are based on field studies. As stated, there is insufficient field history on many current module types to accurately model and predict power loss behavior as a function of materials or design. Several models have been proposed, such as that by Válquez and Rey-Stolle (Válquez & Rey-Stolle, 2008). These primarily have been developed based on long-term fielded modules and attempts to determine power loss based on accelerated testing. These models require validation for a variety of module designs and climates.

It is possible that some of the more recently fielded module designs have not yet reached the wear-out phase (Figure 7). If so, power degradation models based on early life performance may not properly predict that of longer term service. Also, the performance of individual modules may not equate to their performance in strings and arrays at system voltage. This may become more critical, because the industry trend is to move to increasingly higher system voltages.

As Válquez and Rey-Stolle note, at the beginning of a module's operational life, the most common failure mechanism is catastrophic failure, while thereafter degradation will take over as the main failure mechanism. Failures resulting from degradation can start to appear after a few years or up to 50 years depending on the degradation rate. This can be demonstrated in the standard "bathtub" reliability curve (Figure 7), which is a composite of several failure distributions (Válquez & Rey-Stolle, 2008).

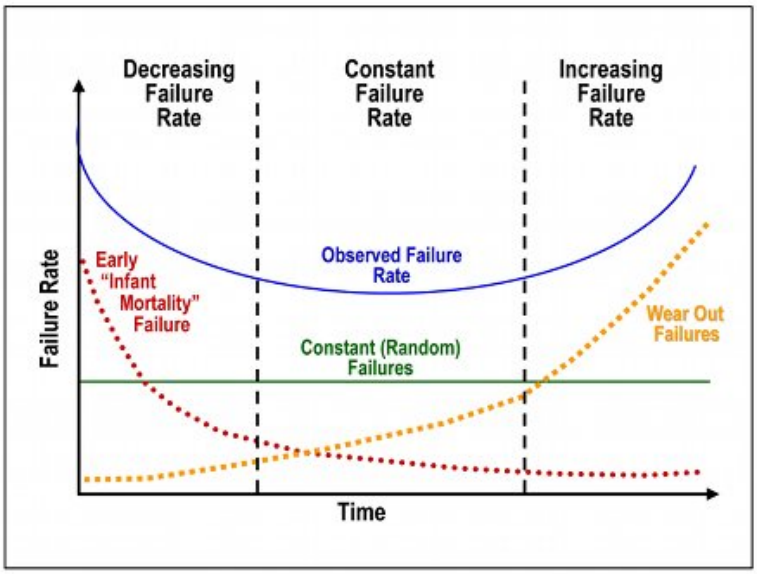

Figure 7. Typical "bathtub" product reliability curve consists of three main failure distributions (Válquez & Rey-Stolle, 2008).

For electronic equipment, the failure rate over the life of the equipment typically has three distinct periods (Klutke, Kiessler, & Wortman, 2003). For mechanical equipment, a similar curve exists, but with a less pronounced constant failure rate region.

- **Infant Mortality.** In this first phase of the bathtub curve, the failure rate is relatively high because some of the parts used in the manufacturing process are out of tolerance or the processes used in manufacturing are inadequate. The shape of the failure rate curve is decreasing, with its rate of decrease dependent on the maturity of the design and manufacturing process as well as the applied stresses.
- **Useful Life.** The second phase of the bathtub curve is known as the "useful life" and is characterized by a relatively constant failure rate caused by randomly occurring defects. It should be noted that the failure rate is only related to the height of the curve, not to the length of the curve, which is a representation of system life.
- **Wear Out.** The last part of the curve is the wear-out portion. This is where components start to deteriorate to such a degree that they have reached the end of their useful life. Durability is defined as the length of the failure-free or maintenance-free operation period. The basic assumption is that all failures are caused by applied stresses and there are no failures before the end of the failure-free period (useful life) is reached. This process is predicated on being able to quantify the loads or stresses that are applied to the electronic or mechanical components and relate these conditions to cycles to failure for repeating and varying load conditions. Wear out is the process that results in an increase of failure rate or probability of failure as the number of life units increase.

The difference in the durability function is the initial part of the life operation up to the point where failure starts. Wear out is the next step after durability. Reliability descriptions and definitions are contained in the *Reliability Toolkit: Commercial Practices Edition* (Morris, 1993) and in *MIL-HDBK-338 Electronic Reliability Design Handbook* (DOD, 1998). However, "failure" must be carefully defined when discussing PV modules. As Wohlgemuth notes (Wohlgemuth, 2013), for example, individual cell interconnects may fail, but built-in redundancy may prevent any change in module performance even though some specific elements may have "failed." So "failure" may be at either the single interconnect level or the module level depending on the criteria.

BEYOND CURRENT IEC QUALIFICATION TESTING

As noted by Wohlgemuth and Kurtz (Wohlgemuth & Kurtz, 2011b) and demonstrated by the PV industry's rapid growth, the current IEC tests have been fairly successful in weeding out poor modules. The degradation rates reported by Jordan and Kurtz (Jordan & Kurtz, 2012) indicate that the tests have been quite successful in identifying and eliminating module types that suffer large degradation rates early in their lifetime.

By design, however, the qualification tests have limitations. A significant number of commercially available products must be able to pass the test sequence, but the tests do not say anything about which product performs better over the long term. For example, when 10 c-Si module types, all qualified to IEC 61215, were tested beyond the qualification level (500 v. 200 thermal cycles and 1250 v. 1,000 hours of damp heat), only two of them passed the extended test (Wohlgemuth et al., 2006).

The qualification tests do not specifically test for wear-out mechanisms, but instead focus principally on early failure mechanisms. Properly designed test-to-failure (TTF) protocols may serve as better indicators of wear out, whatever the impact of combined stresses. The tests primarily identify single cause-and-effect failure mechanisms, do not represent or distinguish the kind of varying and multiple combined stresses present in multiple climates, and are not accelerated enough to determine long-term performance. The PV industry does not know what combined set of stress tests would be a good predictor of a 25-year lifetime, and does not take into account that when the protocols are determined, they are likely to depend on the geographic location where the module is deployed as well as how it is mounted (Wohlgemuth et al., 2006). Some manufacturers (Hasselbrink, 2012) have developed their own internal models based on combined stress tests.

As stated by Wohlgemuth and Kurtz (Wohlgemuth & Kurtz, 2011b), the IEC qualification tests may serve as the basis for longer term reliability purposes given the following preconditions:

- increasing test duration (time or number of cycles);
- using higher stress levels, but making sure that they do not cause failures that are not seen in the field;
- combining stresses;
- evaluating new methods to accelerate the failures;
- using material or coupon tests where it would be impractical or too expensive to use full size modules; and
- using step stresses in which the initial stress starts at the qualification level, then increases to failure, taking care to ensure that the failures are the same ones identified from field exposure.

They also suggest that instead of a simple pass/fail criterion, actual performance be reported to directly compare modules and that the following measurements be considered:

- visual inspections for defects;
- infrared thermography for heat dissipation and to identify high series resistance, hot spots, overheated bypass diodes, etc.;
- electroluminescence to identify discontinuities such as cell cracks or breaks in the junction; and
- dark IV curves to identify small changes in series and shunt resistance.

While modified or completely new individual tests or test sequences may be required, Wohlgemuth and Kurtz provide guidance on extending the existing IEC tests as a possible first step, at least for the comparative evaluation of older fielded designs with current module designs and potential new materials. Wohlgemuth and Kurtz (Wohlgemuth & Kurtz, 2011a) propose:

- **Thermal Cycling.** The current 200 thermal cycles (TC) in the IEC test does not appear to represent 25 years service in most climates. Various levels of cycles from 400 to 1,000 have been proposed, although it has been shown that well designed and manufactured modules can survive 1,500 TC without appreciable power loss (Wohlgemuth & Kurtz, 2011b). If extended to a preset number of cycles at many times the qualification level or run until one of two module types begins to degrade in output or exhibit other detrimental changes, it could serve as a differentiator. If no changes are seen, then it is presumed the two constructions would have similar field performance for failure modes caused by thermal cycling.
- **Damp Heat.** The 85°C/85%RH 1,000 hour test is likely at the practical limits for acceleration for damp heat, because these conditions probably do not happen in the real world. Different module technologies and designs perform quite differently in the damp heat 1000 (DH1000) test, and the correlation to field performance is questionable. For comparative testing, reporting the hours to some measureable degradation such as power loss is likely the most that can be expected. As Kurtz (Kurtz, 2013) notes, "Ultimately, it may be appropriate to apply different versions of the damp heat test to different module constructions."
- **UV/TC50/HF-10.** This leg of the IEC test sequence consists of UV-A/UV-B exposure, followed by 50 TC and 10 HF cycles. It is primarily a module package test with failures usually indicating inadequate interlayer adhesion or encapsulant cure. Wohlgemuth and Kurtz recommend not extending the 10 HF cycles, because it is not really an identified wear-out mechanism, and adding dynamic mechanical load to the sequence leg.
- **Dynamic Mechanical Load.** IEC 61215 only contains a static mechanical load test following the accelerated stress tests. Wohlgemuth and Kurtz suggest that a dynamic mechanical test would better identify modules with cells prone to breakage and power loss. Static loading has often been equated to the mechanical load effects of built-up snow, while dynamic loading is probably closer to the multi-axial irregular frequency of variable wind force. Although neither has been thoroughly defined, there are models from the building materials and other industries that may be of value to the PV community regarding wind load simulation.
- **UV Materials Test.** The UV exposure in IEC qualification is only a pre-screening test to identify UV-sensitive bonding issues and is not long enough to address the UV stability of module polymeric materials in a 25-year lifetime. As there is no agreement between UV dose and years in the field, a comparative test between old and new materials for a proposed 26 weeks or until observed degradation could be a starting point, based on prior work by Wohlgemuth et al. at BP Solar (Wohlgemuth et al., 2006).
- **Potential Induced Degradation (PID).** There are recent reports of significant degradation of modules mounted at the negative-voltage end of high voltage strings. Degradation appears to be related to voltage-induced migration of ions along current paths, exacerbated by the presence of high humidity or water. Preliminary indications are that module design influences the susceptibility to this effect. Hacke (Hacke, 2012) has proposed one test methodology

Adding a combined temperature/humidity/voltage-bias element to the IEC test sequence is recommended at a minimum, and this is included in draft standard IEC 62804 Ed. 1.0, *System Voltage Durability Test for Crystalline Silicon Modules.*

Alternate Durability Test Proposals

To address the gap between IEC qualification tests addressing infant mortality and longer term performance/durability/reliability testing, a number of global research and standards development activities are currently underway. Some of these enjoy open participation while others are closed or otherwise proprietary. It is beyond the scope and ability of this report to address all of these activities, but the most notable and applicable at the time of this report will be summarized.

One of the principal efforts currently underway to address PV durability, performance, and reliability was initiated through a cooperative effort between NREL in the United States, the European Commission's JRC, and Japan's National Institute of Advanced Industrial Science and Technology to form the International Photovoltaic Module Quality Assurance Task Force (IPVMQATF). The purpose of the initiative is to develop improved testing in support of standards development, and to develop a comprehensive quality assurance (QA) manufacturing guideline, including a PV module rating system and a guideline for a PV module manufacturing QA system.

Participants include a large number of interested parties from all sectors of the industry—materials suppliers, module manufacturers, academic and research organizations, and testing and standards development organizations (SDOs). Many of the principals are key members of IEC and other standards committees. Due to time zone and travel logistics, the effort is divided into several working groups (Figure 8) in three main geographic theaters: Japan and eastern Asia, Europe, and the Americas. All work will then be compiled and participant consensus sought. The task groups include:

- Task Group 1: PV QA guideline for manufacturing consistency—leaders Ivan Sinicco, Yoshihito Eguchi, Gunnar Brueggemann, Alex Mikonowicz, Zhou Wei
- Task Group 2: PV QA testing for thermal and mechanical fatigue including vibration—leaders Chris Flueckiger, Tadanori Tanahashi
- Task Group 3: PV QA testing for humidity, temperature, and voltage—leaders John Wohlgemuth, Takuya Doi, Neelkanth Dhere
- Task Group 4: PV QA testing for diodes, shading, and reverse bias—leaders Vivek Gade, Yasunori Uchida, Paul Robusto
- Task Group 5: PV QA testing for UV, temperature, and humidity—leaders Michael Koehl, Kusato Hirota, Jasbir Bath
- Task Group 6: Communication of PV QA ratings to the community—leader David Williams
- Task Group 7: PV QA testing for wind and snow loading—leader Jorge Althaus
- Task Group 8: PV QA testing for thin-film PV—leaders Neelkanth Dhere, Veronica Bermudez, Shuuji Tokuda
- Task Group 9: PV QA testing for CPV—leaders Itai Suez and Nick Bosco

Figure 8. International PV Module Quality Assurance Task Force working groups.

One stated goal of the IPVMQATF is to develop a climate-related PV module rating system. An example of such a system has been proposed by Hirota (Hirota, 2011) (Figure 9).

Requirements for Cryst-Si Module (conceptual)

'TORAY' Innovation by Chemistry

Climate in region	Mounting Configuration			
	Roof-fit	Roof top (Close roof)	Open Rack (on Field or Roof)	Tracking
High mountain	TE * UVF*** TC,HF** SL***	TE * UVF*** UVB* TC,HF** SL***	TE * UVF*** UVB** TC,HF** SL***	?
High latitude region (Low temp)	TE * UVF** TC,HF** SL***	TE * UVF** UVB* TC,HF** SL***	TE * UVF** UVB* TC,HF** SL***	?
Middle latitude region (Moist)	TE** UVF** TC,HF** SL**	TE ** UVF** UVB* TC,HF*** SL**	TE * UVF** UVB* TC,HF** SL***	?
Middle latitude region (Dry)	TE** UVF** TC,HF** SL**	TE ** UVF** UVB* TC,HF** SL**	TE * UVF** UVB* TC,HF** SL***	?
Low latitude region (Moist)	TE*** UVF** TC,HF*** SL**	TE ** UVF** UVB* TC,HF*** SL**	TE ** UVF** UVB* TC,HF*** SL***	?
Low latitude region (Dry)	TE*** UVF*** TC,HF*** SL**	TE *** UVF***UVB* TC,HF*** SL***	TE ** UVF*** UVB** TC,HF*** SL***	?

Thermal Endurance (TE) :
UV / front side (UVF)
UV / Back side (UVB)
Thermal Cycling or HF (TC,HF with BIAS?):
SNOW& WIND (Static Load) (SL):

X

additional

location	
Marine	Salt spray test
Farmland	Ammonia test

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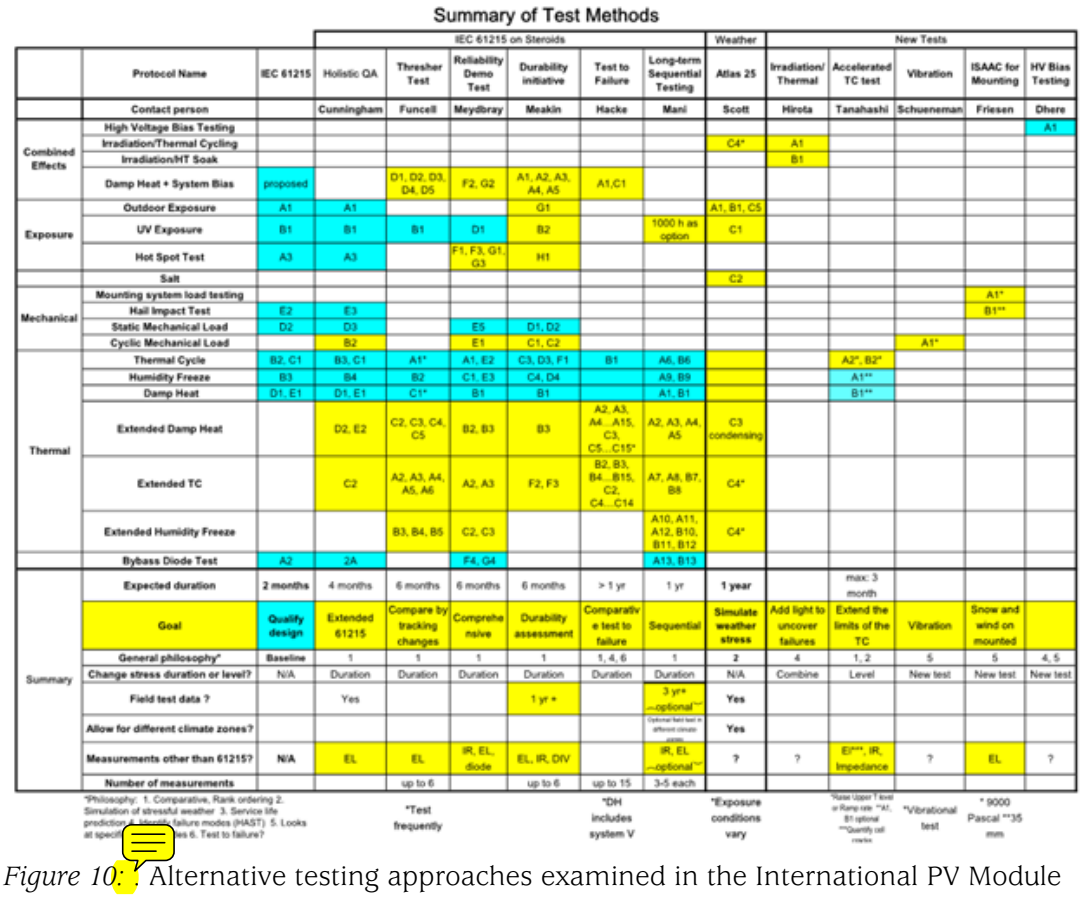
Figure 9: Example of what a climate-based module rating system might include (Hirota, 2011).

The first major effort was to compile a list of testing needs and alternative test methods and testing schemes to address the IEC deficits in long-term prediction of PV module durability. A number of alternative test protocols have been identified in this effort. An abbreviated guide is included here for reference (Figure 10), but is not intended for detailed examination. At the time of this report, only c-Si has been considered; work is just beginning on thin films.



Summary of Test Methods

			IEC 61215 on Steroids						Weather	New Tests				
	Protocol Name	IEC 61215	Holistic QA	Thresher Test	Reliability Demo Test	Durability initiative	Test to Failure	Long-term Sequential Testing	Atlas 25	Irradiation/ Thermal	Accelerated TC test	Vibration	ISAAC for Mounting	HV Bias Testing
	Contact person		Cunningham	Funcell	Meydbray	Meakin	Hacke	Mani	Scott	Hirota	Tanahashi	Schueneman	Friesen	Dhere
Combined Effects	High Voltage Bias Testing													A1
	Irradiation/Thermal Cycling								C4*	A1				
	Irradiation/HT Soak									B1				
	Damp Heat + System Bias	proposed		D1, D2, D3, D4, D5	F2, G2	A1, A2, A3, A4, A5	A1,C1							
Exposure	Outdoor Exposure	A1	A1			G1			A1, B1, C5					
	UV Exposure	B1	B1	B1	D1	B2		1000 h as option	C1					
	Hot Spot Test	A3	A3		F1, F3, G1, G3	H1								
	Salt								C2					
Mechanical	Mounting system load testing												A1*	
	Hail Impact Test	E2	E3										B1**	
	Static Mechanical Load	D2	D3		E5	D1, D2								
	Cyclic Mechanical Load		B2		E1	C1, C2						A1*		
Thermal	Thermal Cycle	B2, C1	B3, C1	A1*	A1, E2	C3, D3, F1	B1	A6, B6			A2*, B2*			
	Humidity Freeze	B3	B4	B2	C1, E3	C4, D4		A9, B9			A1**			
	Damp Heat	D1, E1	D1, E1	C1*	B1	B1		A1, B1			B1**			
	Extended Damp Heat		D2, E2	C2, C3, C4, C5	B2, B3	B3	A2, A3, A4...A15, C3, C5...C15*	A2, A3, A4, A5	C3 condensing					
	Extended TC		C2	A2, A3, A4, A5, A6	A2, A3	F2, F3	B2, B3, B4...B15, C2, C4...C14	A7, A8, B7, B8	C4*					
	Extended Humidity Freeze			B3, B4, B5	C2, C3			A10, A11, A12, B10, B11, B12	C4*					
	Bybass Diode Test	A2	2A		F4, G4			A13, B13						
Summary	Expected duration	2 months	4 months	6 months	6 months	6 months	> 1 yr	1 yr	1 year		max: 3 month			
	Goal	Qualify design	Extended 61215	Compare by tracking changes	Comprehe nsive	Durability assessment	Comparativ e test to failure	Sequential	Simulate weather stress	Add light to uncover failures	Extend the limits of the TC	Vibration	Snow and wind on mounted	
	General philosophy*	Baseline	1	1	1	1	1, 4, 6	1	2	4	1, 2	5	5	4, 5
	Change stress duration or level?	N/A	Duration	Duration	Duration	Duration	Duration	Duration	N/A	Combine	Level	New test	New test	New test
	Field test data ?		Yes			1 yr +		3 yr+ ...optional**	Yes					
	Allow for different climate zones?								Yes					
	Measurements other than 61215?	N/A	EL	EL	IR, EL, diode	EL, IR, DIV		IR, EL ...optional**	?	?	EI***, IR, Impedance	?	EL	?
	Number of measurements			up to 6		up to 6	up to 15	3-5 each						

*Philosophy: 1. Comparative, Rank ordering 2. Simulation of stressful weather 3. Service life prediction 4. Identify failure modes (HAST) 5. Looks at specific failure modes 6. Test to failure?

*Test frequently

*DH includes system V

*Exposure conditions vary

*Raise Upper T level or Ramp rate **At, B1 optional ***Quantify cell cracks

*Vibrational test

* 9000 Pascal **35 mm

Figure 10: Alternative testing approaches examined in the International PV Module Quality Assurance Forum. Blue indicates similarity to IEC 61215 tests, yellow indicates it goes beyond IEC 61215 or differs in some other way. The letters indicate the specific "leg" of each test and the number following is the step in the leg sequence. Designations are provided only to show which tests are included in the various schemes for comparative purposes and do not detail test specifics (Aeby, 2012).

In summary (Wohlgemuth& Kurtz, 2012), the alternative proposals fall into three major categories. The first classification is described as "IEC 61215 on steroids." This consists of protocols that are derivatives of the current IEC 61215 tests either by extending the durations or combining the tests in new sequences or cycles. The second classification is "weather" testing, i.e., test programs that primarily use weather durability testing principles and methods. The third classification is "new tests," which are either add-ons or modifications to a more comprehensive test protocol. A description of the highlights, rationale, and comments for several of the key tests follows.

"IEC 61215 on Steroids"

Holistic QA (BP Solar, Q-Cells, VDE) (Cunningham, Jaeckel, & Roth, 2012; Jaeckel, 2011)

This consists of three components: 1) robustness of design testing, 2) inline quality monitoring, and 3) offline product quality assurance. The requirements are based on IEC 61215/61730 and UL 1703. Conditions were extended to better validate reliability and safety as well as to activate potential latent failure mechanisms, and are based on real failure modes/mechanisms from field data.

The test program consists of the following elements (Figures 11a, 11b, and 12).

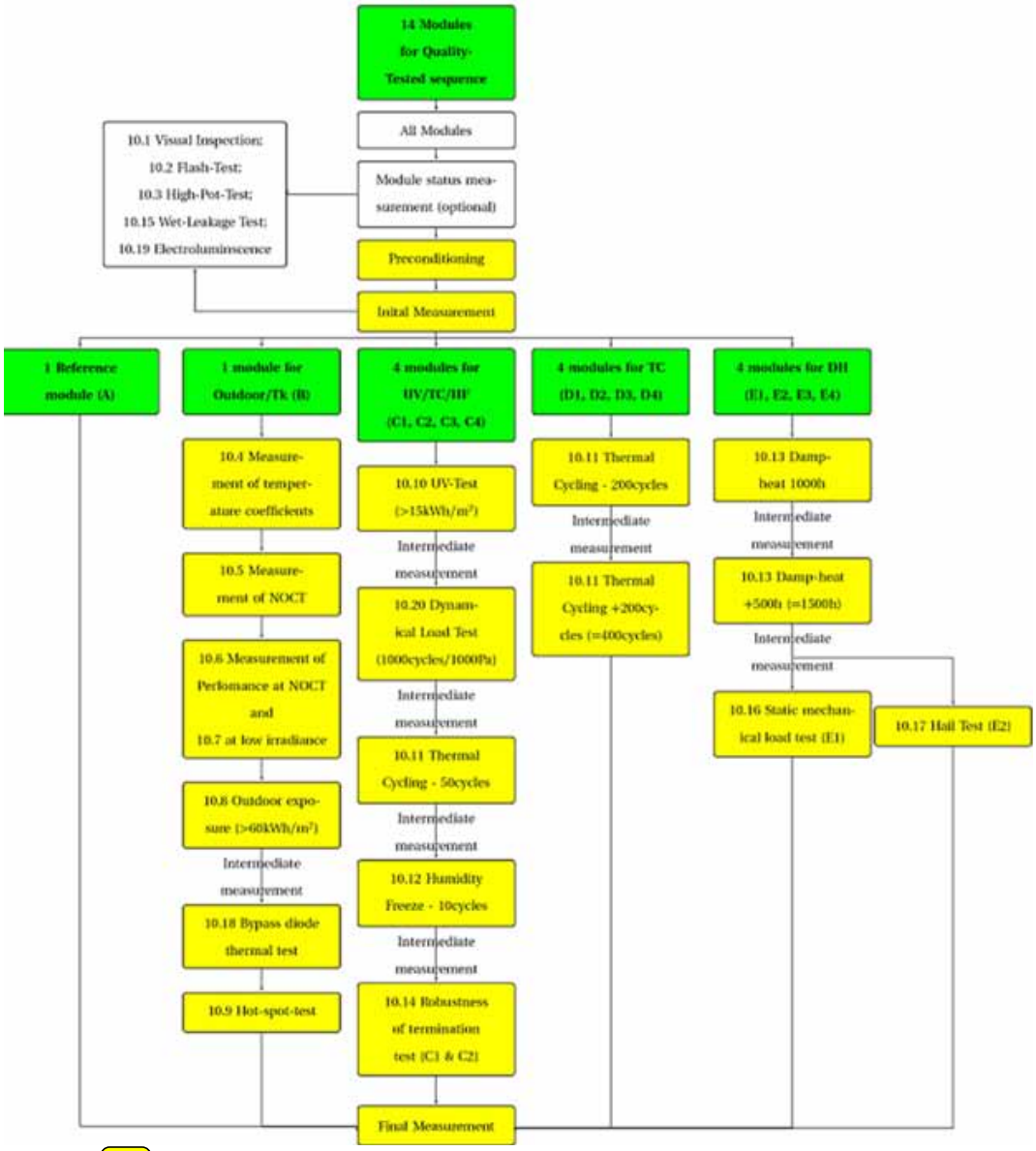


Figure 11a. Holistic robustness of design test sequence flowchart (Cunningham, Jaeckel, & Roth, 2012).

Changes compared to IEC	Reason for change
Extension of thermal cycling (2x IEC) and damp heat (1.5x IEC) test time	Better validate the reliability of products
Doubling the sample size from 2 to 4 for the thermal cycling, damp heat and humidity freeze test sequences	Increase statistical significance of results
Inclusion of a mechanical cycling test after the UV-preconditioning test	Study the impact of wind loading on the modules performance and reliability
Maximum power degradation reduced to 5% after a full test sequence compared to 8%	Increased confidence level for return of investment as well as minimizing the risk for early failures by combining lower allowed power degradation with increased test times.

Figure 11b. Holistic robustness of design test compared to IEC (Cunningham, Jaeckel, & Roth, 2012). Note that IEC = International Electrotechnical Commission and UV = ultraviolet.

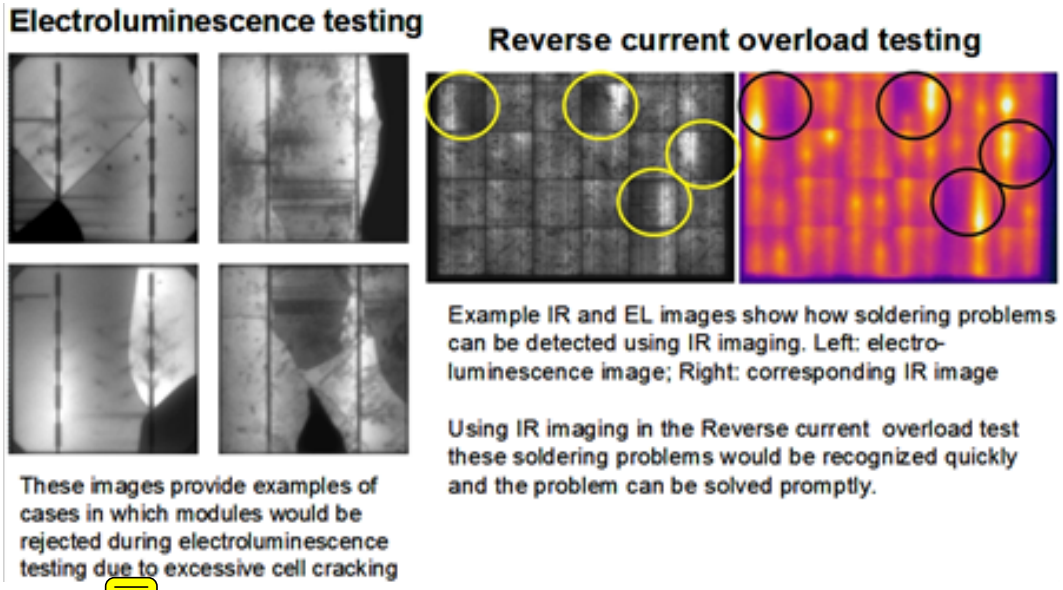


Figure 12. Holistic inline quality monitoring measurements (Cunningham, Jaeckel,& Roth, 2012). Note that IR = infrared and EL = electroluminescence.

Information on Part 3, offline product quality assurance of the holistic robustness program, has not been included, because it is not a durability/reliability test addressed in the scope of this report. Advantages of this program include increased number of modules, extended thermal cycling and damp heat tests, electroluminescence and infrared imaging, and more comprehensive interim measurements.

Thresher Test (Kuhn & Funcell, 2011)

So named to refer to "separating the wheat from the chaff." Based on IEC 61215 tests using eight modules with data taken at interim pulls plus initial and final (Figures 13, 14).

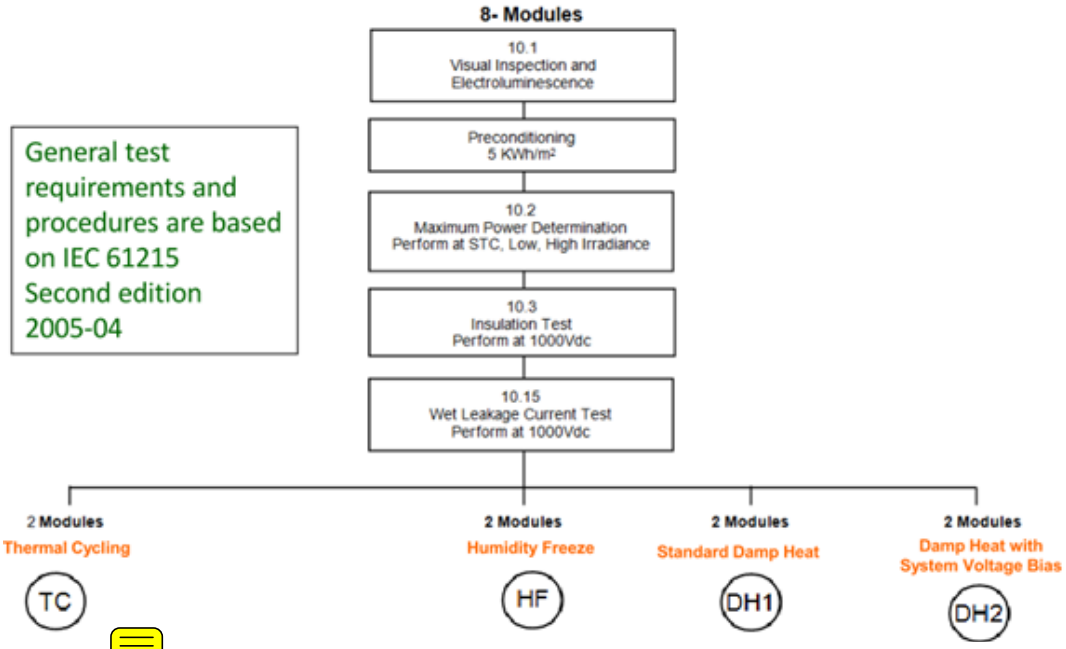


Figure 13. "Thresher test" process flow (Kuhn & Funcell, 2011). Note that IEC = International Electrotechnical Commission, STC = standard test conditions, and Vdc = direct current voltage.

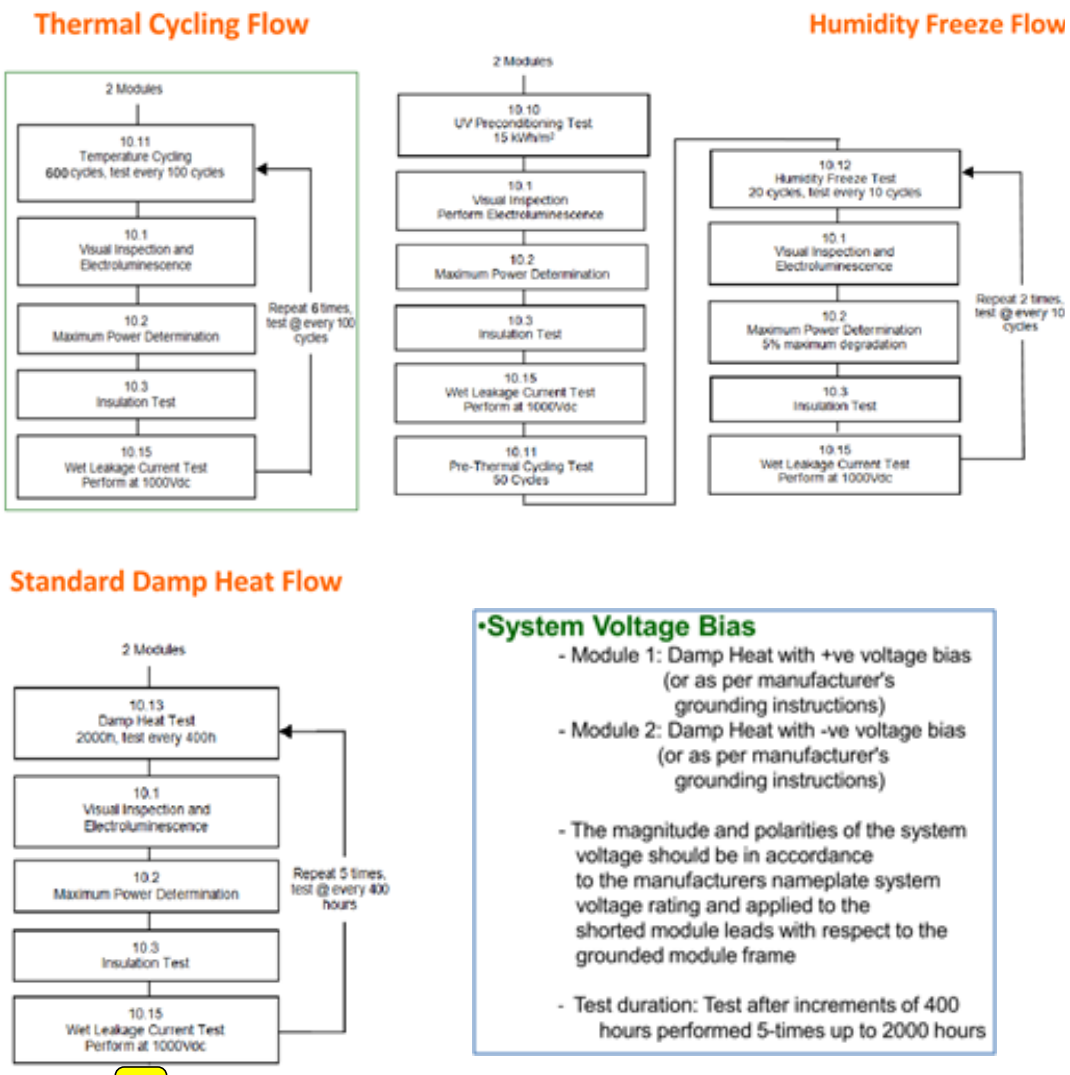


Figure 14: "Thresher test" details (Kuhn & Funcell, 2011).

The "Thresher Test" is designed to gather and report degradation through the course of the test sequences rather than being a pass/fail test. The test is terminated if power output degrades more than 20% from initial test data. At the beginning and end of each test sequence, the power drop, leakage current reading, visual observations, and defects (per IEC 62125, Clause-7) are reported. It is designed as a third-party test with data reported to the manufacturer.

Key differences from standard IEC testing include additional interim inspections and measurements such as electroluminescence, maximum power, insulation, and wet leakage current tests. The thermal cycling is extended from 200 to 600 cycles with measurements every 100 cycles. UV preconditioning and 50 thermal cycles as in IEC 61215 are followed by 10 humidity freeze cycles repeated twice with measurements every 10 cycles. Damp heat is doubled to 2,000 hours with measurements every 400 hours. An additional 2,000 hour damp heat test and measure cycle, as above, is performed with module frames at plus and minus rated system voltage relative to ground (Hacke, 2011).

TÜV Rheinland Long-Term Sequential Test (LST) (TamizhMani, 2011)

A commercially developed test sequence (Sopori, 2012) within TÜV's larger performance scheme offering and described as mid-level "to verify quality for medium confidence." The sequence is shown in Figure 15.

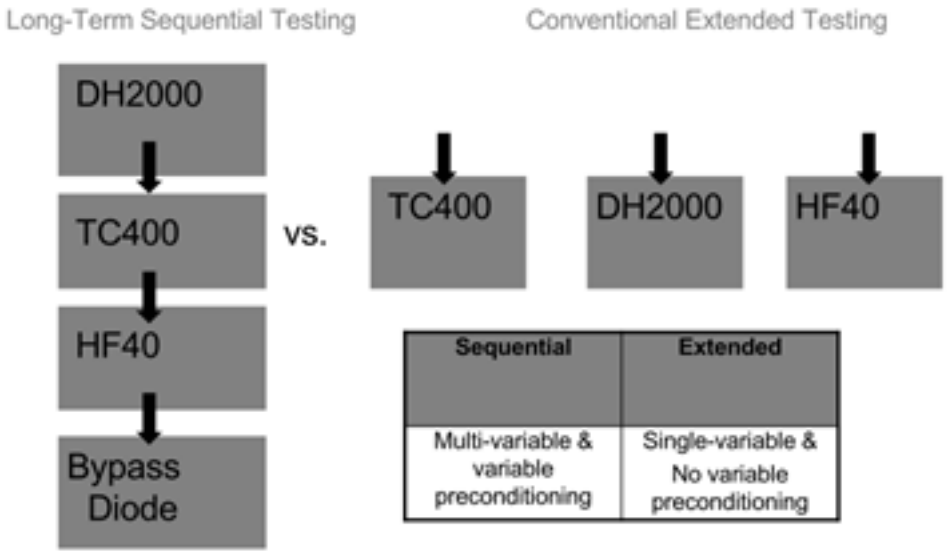


Figure 15. TÜV Rheinland Long-Term Sequential Test sequence compared to conventional extended testing (TamizhMani, 2011). Note that DH = damp heat, TC = thermal cycles, and HF = humidity freeze.

IEC 61215 test in which each one primarily undergoes only one stress test. In addition, each test step is extended, and is therefore two to four times more severe than in IEC 61215. Pre- and post- tests consist of current-voltage (IV) parameters, dry Hipot, wet resistance, and visual inspections. Interim measurements (as above) are made on the following schedule with interim measurements at each interval (dielectric withstand, wet leakage current, maximum power, and visual inspections):

- damp heat: 1,000, 1,250, 1,500, 1,750, and 2,000 hours;
- thermal cycling at 200, 300, and 400 cycles;
- humidity freeze at 10, 20, 30, and 40 cycles; and
- bypass diode test at end of sequence.

Failure is based on more than 20% power loss. The test sequence is estimated to take one year and involves three modules. A "plus" version is offered that adds a dry exposure to UV-A/UV-B light in the test sequence. Following standard IEC pre-conditioning, interim measurements (as above) are made at 200, 300, 600, 800, and 1,000 hours. Also available in "plus" are optional outdoor exposures of test sequenced modules at TÜV locations in Japan, Arizona, Germany, Shanghai, Taiwan, and India for two to three years or more. "Plus" also has additional "plus" options as shown in Figure 16.

Intent or Degradation	IEC Standards 61215, 61730-2 & ANSI/UL1703	TUV Rheinland Long-term Sequential Tested More severe than international standards	TUV Rheinland Long-term Sequential Tested PLUS The most advanced and customizable sequence available	
UV Preconditioning	15 KWh Exposure		Optional Plug-in-1000 h Dry Exposure split into 200 h blocks	
Climatic Testing	Damp Heat- 1000 hours	2 X IEC Standards- Damp Heat 2000 hours split into 250 hour test blocks		**"Long-term Sequential Tested"** is an accelerated test sequence that is designed to be greater severity than the IEC61215, 61730-2 standards. Manufacturers can request their 2 samples to be submitted to the sequence.
	Thermal Cycling- 200 Cycles	2 X IEC Standards- Thermal Cycling- 400 cycles split into 100 hour test blocks		
	Humidity Freeze- 10 Cycles	4 X IEC Standards - Humidity Freeze 40 cycles split into 10 cycle test blocks		
Stresses	IEC Hotspot- 5 hour exposure UL1703-120 hour IR lamp		**Optional Plug-in**- more samples for Extended Hotspot 2 X IEC Standards- Hotspot 20 hours	
	Bypass Diode	Bypass Diode Test at end of the Sequence		
	Hail Test		**Optional Plug-in**- more samples (for thunderstorm regions) 35mm Size Hail Test at the end of the Sequence	**"Long-term Sequential Tested PLUS"** comprises of additional component plug-ins designed to be added AFTER/or in parallel to a Long-term sequential sequence that is ongoing.
Mechanical	2400Pa or 5400Pa for Heavy Load		Optional Plug-in- more samples for alpine 5400Pa, 7000Pa and 8000Pa.	
Corrosion	Damp Heat- 1000 hours	X IEC Standards- Damp Heat 2000 hours split into 250 hour test blocks		
Extreme Conditions Configurable Module			Optional Plug-in- more samples to simulate extreme conditions e.g. desert climates (TUV PTL), tropical (Indonesia) and sub-tropical (Taiwan/India) climates or alpine conditions (Germany)	
Outdoor Testing	Outdoor Exposure ~5.5 KWh		Optional Plug-in- more samples to be placed outdoor for 2-3+ years in conditions that manufacturer requires	
Operational Mpp & Degradation Analysis			Path Degradation Analysis based on calculations from "LST" indoor chamber testing data AND Outdoor Exposure Testing data	

Figure 16. TÜV Rheinland Long-Term Sequential T[illegible]T) and "LST-plus" comparison to IEC 61215 (TÜV RheinlandEnergie&Umwelt GmbH, 2011). Note that IEC = International Electrotechnical Commission, LST = long-term sequential test, PTL = Photovoltaic Testing Laboratory, and UL = Underwriters Laboratories.

Fraunhofer Photovoltaic Durability Initiative (PVDI) (Fraunhofer ISE & CSE joint project) (Meakin, 2011).

The Fraunhofer Photovoltaic Durability Initiative (PVDI) (PVDI, 2011) seeks to "provide ranking of PV modules relative to their likelihood to perform reliably over their rated service life." A goal of the program is to regularly publish durability reports and rankings. The PVDI program is intended to test and generate comparative ratings on commercially purchased modules. The test sequence is described in Figure 17.

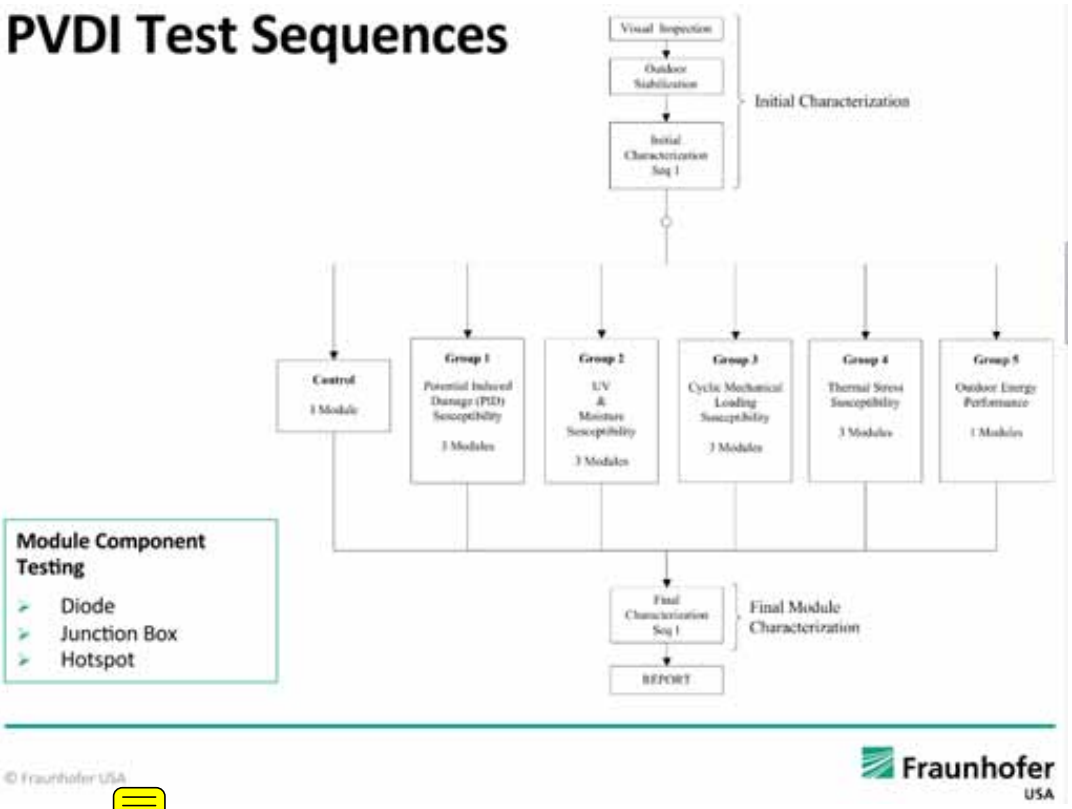


Figure 17. Fraunhofer Photovoltaic Durability Initiative (PVDI) test sequences (PVDI, 2011). Note that UV = ultraviolet.

Key features of the PVDI test sequence include:

- potential-induced degradation test sequence, positive and negative grounding;
- UV combined with damp heat—UV exposure equivalent to at least one year with partial saturation;
- cyclic loading at -40°C followed by thermal cycling to exacerbate crack separation;
- extended thermal cycling;
- long-term exposure at maximum power point (MPP) with intermittent IV measurements
- infrared (IR), electroluminescence (EL), and dark IV measurements;
- 6 month test time (except continued outdoor testing);
- evaluation of commercially purchased modules, results quantitative rather than pass/fail; and
- test sequences designed to provide durability assessments of four operational environments:
    - o high voltage stress;
    - o high UV radiation stress;
    - o thermal-mechanical stress (high wind, high snow load); and
    - o thermal stress with high temperature variance.

A key feature of the PVDI is the use of 13 modules (plus one control) for somewhat improved statistics and outlier identification compared with IEC 61215.

PV Evolution Labs Reliability Demonstration Test (PV Evolution Labs)

This is a commercial test program (Meydbray, 2012) designed to "provide the industry a robust and comprehensive test protocol to evaluate long-term PV modules aging behavior…." and is primarily based on extending individual IEC 61215 tests and adding electrically biased damp heat and mechanical load sequenced with thermal cycling and humidity freeze as described in Figure 18.

Reliability Demonstration Test

Test	Duration	Primary Degradation Behaviors Stimulated
Thermal Cycling	600 cycles	Solder joint degradation, cell cracks, Jbox failure, Polymer embrittlement, solder peaks cutting through backsheet
Damp Heat	2,000 hours	Delamination, Corrosion, polymer embrittlement, discoloration, cell degradation, Jbox failure
Damp Heat w/ +1kV	600 hours	In addition to aging behavior above: Ion migration, electrolytic corrosion, polarization
Damp heat w/ -1kV	600 hours	
Humidify Freeze	30 cycles	Solder joint degradation, cell cracks, Jbox failure, Polymer embrittlement, delamination, cell degradation
1. Mechanical Load 2. Thermal Cycling 3. Humidity Freeze	1. 1,000 cycles 2. 50 cycles 3. 10 cycles	Cell cracks leading to performance loss, solder joint degradation, delamination, frame fatigue
UV Exposure	90 kWh	Discoloration, embrittlement, cell degradation, delamination

- Details and frequency of module characterization is very important
- All modules sun soaked before testing starts

Module Characterization

1. Visual Inspection, Light IV, Dark IV, Wet Hipot at 1kV, EL Image, IR Image

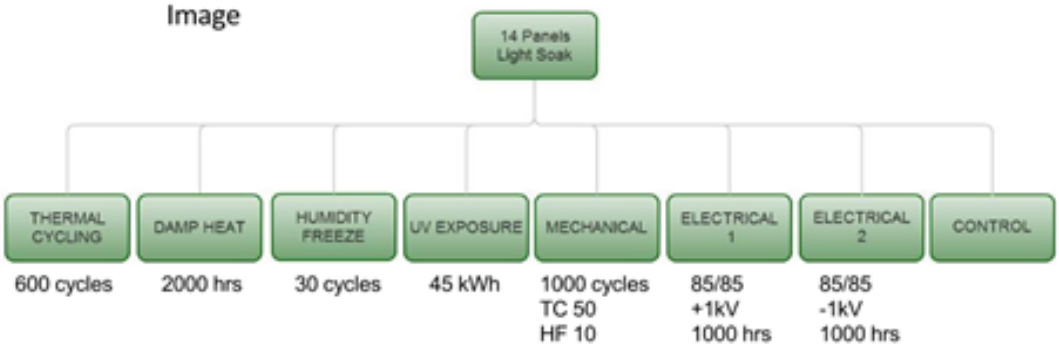


Figure 18. PV Evolution Labs reliability demonstration test protocol (Meydbray, 2012). Note that kV = kilovolt, kWh = kilowatt-hour, IV = current-voltage, Hipot = high potential, EL = electroluminescence, IR = infrared, TC = thermal cycles, and HF = humidity freeze.

NREL Test-To-Failure Protocol (Hacke, 2012)

NREL's Carl Osterwald (Osterwald, 2008) originally proposed a methodology that may be used to obtain more quantitative information about PV module reliability than the existing IEC 61215 tests. The TTF protocol falls somewhere between qualification testing and true accelerated life testing. TTF extends the artificial indoor stresses by continuing the environmental chamber testing until module failure is detected. "These lengths are not module lifetimes, but they can be used to compare the reliability of different modules on a quantitative basis." Six modules are tested, plus one unexposed control.

Thermal cycling and damp heat were selected for the TTF protocol because these stresses have been reported by laboratories performing standard qualification testing to cause the highest numbers of failures. Electrical forward biased thermal cycling is used for both c-Si and thin films. In damp heat testing for test sequences B & D (Figure 19) a system bias voltage is applied between the module's frame grounding points and the shorted output leads, at both polarities. Measurements consist of MPP, dielectric withstand, wet insulation resistance, visual inspection, and optional infrared imaging. Originally, power output less than 50 % (different measurements for c-Si and thin films) and other parameters were included as definitions of failure, but that was later revised (Hacke, Terwilliger, Glick, Trudell, Bosco, Johnson, & Kurtz, 2010) to power loss of 20 % among other parameters to better correspond to today's average 25-year module warranties. Wet leakage current failure was also redefined from 50 microamperes (μA) to 1 mA.

		Sequence							
		A. Control		B. Damp Heat with Bias		C. Thermal Cycling		D. Alternating B/C	
		5 kW hrs/m² light soak							
Round	1			DH+	DH-	TC	TC	DH+	DH -
	2			DH+	DH-	TC	TC	TC	TC
	3			DH+	DH-	TC	TC	DH+	DH -
	4			DH+	DH-	TC	TC	TC	TC
	…								
	15			DH+	DH-	TC	TC	DH+	DH -

- DH refers to 1000 hrs 85°C and 85% relative humidity, IEC 61215 Ed. 2 sec. 10.13
- DH+(-) indicates +(-) voltage bias of 600 V or module's rated system voltage (whichever is greater) on shorted module leads with respect to grounded frame
- TC refers to 200 cycles between -40°C and 85°C, IEC 61215 Sec. 10.11 (I_{mp} applied when T> 25°C)
- Light and dark I-V, electroluminescence, thermal imaging, IEC 61215 dielectric withstand, insulation resistance, and visual inspection are done at the end of each round of stress testing

Figure 19. NREL Test-to-failure protocol test sequence (Hacke, 2012). Note that DH = damp heat, TC = thermal cycle, IEC = International Electrotechnical Commission, and I-V = current-voltage.

Other Extended Tests

Over the years, a number of manufacturers and others have also modified or extended the IEC test sequence in an attempt to better test for durability and reliability. The following are two representative examples:

- BP Solar (Wohlgemuth, 2003) increased the IEC 61215 tests to 500 thermal cycles with peak power current flow and 1,250 hours of damp heat.
- Suniva (O'Neill, 2012) extended damp heat and thermal cycling (Figure 20).

Figure 20: Suniva extended testing (O'Neill, 2012). Note that IEC = International Electrotechnical Commission and UL = Underwriters Laboratories.

SunPower (Kim & Bunea, 2012) extends IEC 61215 to 500 thermal cycles, 4,000 hours damp heat, and 110 cycles humidity freeze, and performs static load (2,400 Pa). SunPower also performs multi-climate outdoor and ISO 4892-3 UV testing to 10 years (AM1.5 @ 6 hours/day). Extended hot-spot shading and ± voltage-induced degradation tests are also performed. Additional materials tests such as backsheet and encapsulant thermal and UV stability, and 2,200 thermal cycles (-40°C to- 90°C) for solder joints are performed.

Schott Solar (Mills & Schonfield, 2009) performs more than 2X static loading (5,400 Pa), 400 thermal cycles (-40°C to- 90°C), 2,000 hours damp heat, 20 week "combi" test (3 days thermal cycling and 4 days damp heat), and 20 weeks outdoor exposure.

Summary of Extended IEC Tests Approaches

The extended IEC 61215 tests focus on several key areas (Wohlgemuth & Kurtz, 2011):

- increasing the number of cycles, or test duration, typically by a factor of about 2X;
- increasing the stress limits (e.g., 90°C v. 85°C upper limit in thermal cycling);
- sequencing several tests on the same module(s) to provide multiple rather than single stresses;
- adding system high voltage bias representative of in-service conditions, especially during high humidity tests;
- adding static or dynamic load to represent snow load and wind mechanical stresses; and
- increasing both the frequency and type of evaluations (such as electroluminescence, thermal imaging, dielectric withstand, and wet leakage current).

Potential advantages of this approach include:

- it builds on a body of prior experience in replicating many known field failures,
- it is relatively easy to implement with commonly available equipment used in IEC qualification testing, and
- some extended approaches (those not requiring new test sequencing) may be implemented at the same time on the same modules as current IEC 61215/61646 qualification testing.

Potential disadvantages include:

- This approach may not represent multiple simultaneous stresses of in-service conditions required to reproduce some degradation mechanisms. This approach has, however, proven effective for some degradation mechanisms, for example voltage-temperature-humidity for PID.
- This approach may not induce some longer term degradation and failure mechanisms. Some tests, however, such as extended thermal cycling, do appears effective for reproducing thermo-mechanical wear out.
- Modeling power loss and correlating accelerated test to field conditions is still elusive.
- This approach does not correlate to specific climates.
- There may be inadequate UV/solar radiation exposure; most tests are conducted in the dark or with externally applied electrical bias, and may not reproduce sunlight effects in operating modules.

A simple extension of existing tests may or may not shift the focus from infant mortality problems to wear out mechanisms. As Kurtz notes, it is useful to find field data to identify the most common wear-out mechanisms and then revisit the test design to see if these are the right tests (Kurtz, 2013).

Weather Tests

The second category of identified tests, "Weather," is designed to address several of these shortcomings, most notably performance, durability, and reliability in specific climates. This category also relates these shortcomings to accelerated test conditions or combines more stresses simultaneously as Wohlgemuth and Kurtz recommend (Wohlgemuth & Kurtz, 2011). Due to the long times required for normal outdoor exposure tests, accelerated tests need to be developed that are likely to replicate longer term degradation and wear out resulting from external environmental stresses, device metastability issues, and/or normal (and transient) in-service electrical operation.

Presently, there are several research efforts underway to understand current PV module degradation through long-term outdoor exposures in various climates. There are also several comparative PV demonstration projects underway. Some of these efforts are described elsewhere in this report. The goal of some of these efforts is to link identified long-term field failure mechanisms to short-term accelerated tests, similar to the development of the current IEC qualification tests linking to infant mortality fa[illegible]s. Most of this work is in early stages. One test sequence, identified in the ~~IPVMQAF~~ (Figure 9) is currently focused on weather degradation.

Atlas 25+ PV Module Long-Term Du[illegible]ity Test (Scott, 2011; Zielnik, 2010)

The standard test sequence is shown in Figure 21.

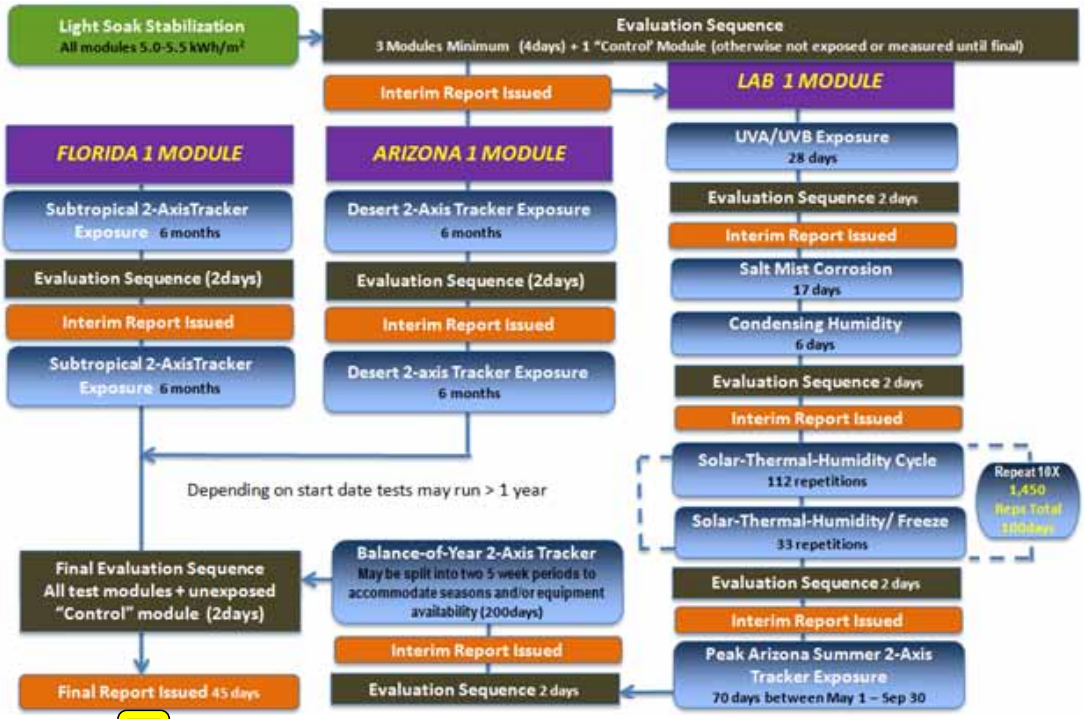


Figure 21. Atlas 25+ "standard" test sequence (Zielnik, 2010).

The sequence uses two modules for outdoor two-axis tracking, one each in south Florida and Arizona for one year. A third "lab" module goes through a sequence of UVA/UVB exposure (2X IEC duration), salt fog corrosion (17 days), condensing humidity (6 days), combined solar/environmental chamber cycles (100 days), Arizona peak summer two-axis tracking (10 weeks), and outdoor Arizona solar tracking for the balance of the year. Measurements include IV curves, digital, IR and EL images, visual inspection, and wet leakage current.

Atlas describes the core solar/environmental chamber sequence as consisting of climate-based conditions in two alternating cycles representing spring/summer/autumn and winter and characterized by a high number of cycles (1,450). Apart from some PV-specific considerations, modules are essentially treated as a "black box"—i.e., tests reproduce climate conditions and not specific failure modes. Modules operate under resistive load at MPP during all outdoor and solar/environmental chamber tests.

The addition of class BBA solar simulation in the diurnal cycles to one of four climates—hot/arid, northern temperate, hot/humid, and a "composite" of the three as a default—is unique. A "plus" version adds additional modules, outdoor climates such as "coastal-marine," and other options. SGS, a global commercial testing organization, incorporates the Atlas protocol into their PV performance and certification scheme.

Potential advantages of this approach include:

- It builds on the body of prior experience in long-term weather durability testing of complex structures.
- It incorporates multiple stresses in a high number of climate-derived cycles.
- It may induce longer term weather related degradation, such as that seen in about 10 years of service.

The module generates power whenever tested under natural or simulated sunlight. Potential disadvantages include:

- It may require longer test times to induce the degradation typical of a module with a 25-year warranty.
- A limited number of modules (typically one) are tested in the full sequence.
- Resistive loading does not produce the higher system voltages of arrays.
- It requires specialized environmental chambers with full solar simulation.
- It typically extends the test time to about four times that of current IEC qualification tests.
- Because this test method is not related to duplicating any observed field failures, it is not clear if the results have any relationship to actual long-term field performance.

Other Tests

The third category of accelerated tests identified in the IPVMQATF (Figure 10) is "add-ons" to IEC tests for specific failure modes. One example is a UV-thermal combined stress acceleration test (Doi, 2011). This test notes that standard thermal cycling and constant temperature stress tests are performed with light irradiated stress (up to three times UV). A second is a rapid thermal cycling (400°C/hour) proposed by Tanahashi (Tanahashi, 2011). Another is the incorporation of wind-induced vibration simulation (Schueneman, 2012).

These add-on tests are largely experimental or in development at this time, so they will not be detailed in this report. The various approaches to specific testing schemes do, however, point to the fact that in terms of moving from basic qualification to mid-level durability assessment, much is still unknown. Here are examples of uncertainties related to the current IEC 85°C/85%RH damp heat test as described by Wohlgemuth (Wohlgemuth, 2012):

- There are multiple humidity and humidity/electrical bias degradation modes with widely varying acceleration factors.
- Eight-five degrees Celsius and 85%RH never occur in the real world, nor do steady-state conditions.
- Failure modes occurring after long-term 85/85 testing are not observed in the field.
- The industry needs field data, samples, and analysis methods
- The industry needs to determine what mechanisms are leading to module degradation in the field.
- The industry will have to perform modeling to understand those degradation mechanisms and how they can be accelerated (Kempe, 2013).
- Then the industry will have to design new accelerated stress tests that can duplicate the field failures.

Clearly, much work remains in fundamental research and understanding of module degradation and failure mechanisms for various module designs and technologies in order to develop true predictive durability tests leading to module and system reliability assessment. A key aspect of this is developing statistical degradation and failure mode data from a large assortment of fielded module designs and technologies. This presents a problem, in that most of the current designs have only been in service for 10 to 15 years, although for c-Si some basic designs and materials have a longer track record. An example is to perform comparative testing more severe than the qualification tests on long-term fielded ethylene vinyl acetate (EVA) encapsulated modules and those with new encapsulants in an attempt to duplicate wear-out mechanisms (Wohlgemuth & Kurtz, 2011b). Of course, many original equipment manufacturers are reluctant to share commercial failure information. In any event, the linkage between long-term field degradation and performance in various climates and laboratory tests must be made. Some of the existing efforts underway in this area will be mentioned in this report, although it must be pointed out that there is no large scale long-term effort presently underway and certainly none on a comprehensive scale.

Demonstration Projects and Field Tests

The Japan Electrical Safety and Environment Technology Laboratories have been conducting limited exposures (Masuda, 2011) of several Si module types at four locations in Japan with some dating from the early 1990s. In addition, 67,000 modules (mostly poly-silicon) at 32 sites—some of which have been operating for about 30 years—have been visually inspected.

DOE has very recently established three regional test centers (Granta, Stein, & Lynn, 2012) in the United States (in New Mexico, Colorado, and Florida) where manufacturers can set up systems for monitoring by DOE laboratories to assess all aspects of a PV system throughout its lifetime. This effort is organized in four main areas:

- design evaluation and acceptance testing,
- performance and system monitoring,
- analysis and monitoring, and
- reliability and safety.

TÜV Rheinland and Fraunhofer Institute for Solar Energy Systems are conducting exposures (Köhl, 2011b; Bogdanski, 2011) of three replicas of seven module types under resistive load in urban Germany, the Alps, Israel (desert), Indonesia (tropical), and the Canary Islands (maritime). Apart from special-cause failures (glass breakage, soiling, etc.), power loss at three years is generally within the measurement error. Note, however, that different degradation mechanisms impact different module parameters. The study notes that:

- degradation indication by power loss requires more than three years of outdoor weathering;
- only the determination of significant outdoor degradation data enables a reliable correlation of lab and outdoor degradation;
- power degradation is actually a superposition of several degradation mechanisms, which should be evaluated (measured) separately to correlate them to lab values; and
- outdoor exposure is important to reveal degradation that will not occur in lab testing.

DURABILITY AND RELIABILITY TESTING CONCEPTS

The term "reliability" is frequently used in the PV industry. In order to define a methodology to predict or achieve reliability, the term itself must be adequately understood. Bajaria (Bajaria, 2000) provides a reasonably practical definition as "the measure of unanticipated interruptions during customer use. These interruptions typically arise from unexpected failures. During a reliability test, one important goal is to maximize the opportunities for unexpected failures, so that they can be fixed. A test may appear to be a reliability test and actually be a durability test when opportunities for discovering unscheduled interruptions are unintentionally minimized."

Durability is classically defined as the length of failure-free or maintenance-free operation period. A simpler definition is the amount of use one gets from a product before it deteriorates to a point where it is no longer economical to operate (Tenner & DeToro, 2012).

For PV, this must be more clearly defined. In some circumstances, a power loss of 10% may be as important as a complete failure. In others, any output requiring minimum maintenance may have value. The basic assumption in durability is that all failures are caused by applied electrical, mechanical, thermal, or other stress and there are no failures before the end of the failure-free period (useful life) is reached.

This process is predicated on being able to quantify the loads or stresses that are applied to the electronic or mechanical components and relate these conditions to cycles or duration to failure for repeating and varying load conditions. Therefore, a durability test is a test to failure to determine the length of the failure-free period. Units are stressed as expected in the operating environment or are accelerated by increasing the stress levels. Testing is stopped at failure of all the units.

Adams (Adams, 2011) simplifies durability and reliability further:

- In a formal manner, reliability is the probability (likelihood) that an item (e.g., system, subsystem, component, part) will perform its intended function with no failures for a given time period under a set of operating conditions (environment).
- In brief, reliability is the likelihood of failure-free performance for stated conditions (function, time, environment).
- A durable component is designed to have a longer "useful life" or is designed for damage tolerance.

Bajaria (Bajaria, 2000) notes that to assess reliability or durability, we rely on internal qualification tests because it is not possible to calculate either reliability or durability from first principles alone. Even if we can generate mathematical models to estimate reliability or durability, the models still need to be verified by testing. A durability test is a subset of a reliability test. We may be able to estimate durability from a reliability test but not vice versa. Both these tests appear very similar from a testing mechanics' viewpoint and it is often difficult to discern any differences. Bajaria provides a good reference for what constitutes a true reliability test (Figure 22).

Reliability test should be	Actual industry practice	Best practice
Reliability test should reflect a true customer. Actual likely users in an actual environment should be testing products.	In most instances, industry uses expert or well-trained employees to simulate customers' feedback. Well-trained employees are not a true reflection of potential customers. Employees have vested interest and therefore, one cannot consider the data as 100% valid.	Use actual users and actual environments for tests whenever possible.
If testing must be done in a laboratory, a reliability test should reflect a true user environment.	Many tests are conducted in a laboratory under a simulated, single environment. The outcome of such tests most likely represents durability rather than reliability.	If only laboratory tests are possible, measure customer environments and design tests accordingly, so that all environments and the operating profile are included simultaneously.
The reliability test should reflect a sample coming from a true production environment.	In many instances, prototype parts are used for the test. Prototype parts may exhibit the validity of physical principles but may not necessarily reflect reliability.	Define reliability at two levels: 1) hardware level D (design level) and 2) hardware level P (production level). Design engineering is considered complete only when both the D level and P level are proven.
Reliability tests should use random samples.	Industry practice is to use pre-qualified test samples. That means, the test samples are inspected and assured to be within specifications before they are subjected to the tests. This, in turn, reduces the chances of observing premature failures. Pre-qualified samples most likely measure durability not reliability.	Use random samples. Or, if pre-qualified samples have to be used, make the pre-qualification scheme a part of the production control plan.
The reliability test should be a validation test, not just a verification test.	Most tests are designed to verify design requirements. These requirements are supposedly a translation of customer requirements. Such tests can be labeled as verification tests. The outcome of such tests most likely measures durability rather than reliability. Additionally, the tests do not reflect the fact that some customer environments may be inadequately translated or some customer environments may be omitted altogether.	Perform verification tests on a smaller sample. Perform validation tests on a larger sample.

Figure 22. Reliability testing concepts and best practices (Bajaria, 2000).

Klyatis (Klyatis, 2012) further points out that the vast majority of literature references to reliability tests are actually true durability tests, or stop short of failure at a finite duration as a qualification test.

Despite extensive use of the term "reliability," most of what is being done in the PV industry at best falls under the realm of trying to assess "durability." As Klyatis notes, many types of environmental influences act on a product in real life. Some influences are studied, but many are not. The factors responsible for the influences of environmental stresses in the field are very complicated. One of the most complicated problems is the integrated cause-and-effect relationship of different factor steps including stress influences, effect on output parameters, and degradation.

In accelerated testing, we have two primary means of test acceleration. The first is overstress where one or more levels of a stress condition (such as temperature cycling) are applied at levels in excess of the intended normal service use. The test results are then used to extrapolate estimated performance at the normal stress level. Care must be taken not to exceed the stress strength of the product and induce unrealistic failure.

The second is time compression, where the stress is applied for shorter periods of time to estimate normal service use. This method works best on cyclic fatigue failures, and often a combination of the two approaches is used, such as rapid thermal cycling over an extended range.

Accelerated laboratory tests for durability and reliability fall into several categories. The U.S. Department of Defense Information Analysis Center (Criscimagna, 2013) defines two main categories of accelerated testing:

- Accelerated life testing (ALT) uses a model relating the reliability (or life) measured under high stress conditions to that which is expected under normal operation to determine length of life. It requires:
  - o an understanding of the anticipated failure mechanism(s) and
  - o a knowledge of the magnitude of the acceleration of this failure mechanism, as a function of the accelerating stress.
- Accelerated stress testing uses accelerated environmental stresses to precipitate latent defects or design weaknesses into actual failures to identify design, part, or manufacturing process problems that could cause subsequent failures in the field. It requires:
  - o a thorough understanding, or at least a working knowledge, of the basic failure mechanisms; and
  - o an estimation of item life, which may or may not be a concern.

Accelerated testing may be performed at either the component or equipment level. Accelerated test models relate the failure rate of the life of a component to a given stress such that measurements taken during accelerated testing can then be extrapolated back to the expected performance under normal operating conditions. The implicit working assumption here is that the stress will not change the shape of the failure distribution. Typical models include the Inverse Power Law, Arrhenius Acceleration Model, and Miner's Rule (Fatigue Damage), although there are others. In selecting a model, the key criterion is that it accurately models the reliability or life under the accelerated conditions to that under normal operating conditions. Constant single stress profiles are the easiest to implement, but both non-constant stress profiles and multi-stress profiles can be used.

An accelerated test model is derived by testing the item of interest at a normal stress level and also at one or more accelerated stress levels. Extreme care must be taken when using accelerated environments to recognize and properly identify those failures which will occur in normal field use and conversely those that are not typical of normal use. Because an accelerated environment typically means applying a stress level well above the anticipated field stress, accelerated stress can induce false failure mechanisms that are not possible in actual field use. For example, raising the temperature of the test item to a point where the material properties change or where a dormant activation threshold is exceeded could identify failures that cannot occur during normal field use. In this situation, fixing the failure may only add to the product cost without an associated increase in reliability. Understanding the true failure mechanism is paramount to eliminating the root cause of the failure.

Not all degradation stresses can be “accelerated” (in terms of the applied stress, not material response) at the same rate. For example, irradiance can be easily increased, but time to reach moisture equilibrium may be more difficult. Therefore, any accelerated test has the potential to alter the normal balance of stresses compared to the service environment. This, in turn, may affect or alter specific degradation mechanisms. Further, many stresses in the outdoor environment are interrelated. Unidirectional solar load, for example, may cause a temperature gradient within a module stack that in turn may affect moisture levels and provide thermo-mechanical stress different from exposure in an environmental chamber. Diurnal cycles typically result in an inverse relation of relative humidity and temperature, a relationship not always achieved in climate chamber tests.

In addition, laboratory test steady-state conditions really do not exist outdoors, and longer term chemical degradation mechanisms, such as corrosion of TCO, may not be able to be accelerated with current tests. Degradation or failure modes resulting from combined stress in service, or those resulting from simultaneous or sequential degradation modes, also may be difficult to reproduce or accelerate with single or limited-stress tests. As a result, a fundamental tenet is that any accelerated laboratory tests must be validated with real time service condition exposures and cause-and-effect correlation established. Degradation or failure modes resulting from combined in-service stresses, or those resulting from simultaneous or sequential degradation modes involving different stresses, are often difficult to reproduce or accelerate with single or limited-stress tests.

As this report demonstrates, the current IEC qualification tests overall are generally recognized as insufficient to assess true long-term durability and wear out, although some of them (in current or extended versions) are effective in reproducing many observed PV failure mechanisms. However, as Kurtz points out (Kurtz, 2013), some degradation and failure modes have not been reproduced by the current test approaches, and it is probable that other problems will surface with the continued introduction of new materials and designs.

Because realistic accelerated multiple-stress testing of full-size modules can be quite expensive, there is substantial interest in supplementing full-module testing with materials-level testing. This is predicated on relying more on materials pre-qualification, on the premise that starting with high quality durable materials will more likely result in durable modules. IEC TC 82 Working Group (WG) 2, a standards writing body, has established a materials working group that is looking at material properties and relevant tests. At this time, only polymeric non-balance of systems materials are being addressed. Several parallel groups are working on backsheets and frontsheets, encapsulants, adhesives for attachment, and edge sealants and potting materials to establish durability tests and specifications. An additional overarching weathering/accelerated aging group is providing input and expertise to the materials groups. The goal of the materials group within IEC WG2 is to define uniform and meaningful methods for testing materials. Those tests may eventually be incorporated into standards that define acceptable limits, such as the PV safety standard IEC 61730-1.

Acceleration Factors

Accelerated tests often report calculated or apparent test acceleration factors. These factors are simply a numerical value relating the relative test time to an equivalent in-service time based on the degree of change in a specific property. It is important to note that in most cases acceleration factors for any test condition are only valid for a particular material or product design, a specific end-use climate or service condition, and a specific measurement parameter. In some cases there is a non-linearity of property change with exposure due to increasing stress sensitivity with product age and wear out, deviations from test reciprocity, overlapping or synergistic degradation mechanisms, and other factors. Therefore, apparent acceleration factors may not be constant across all measurement intervals due to non-linearity in either the field or accelerated test parameter response.

Assuming that test acceleration is linear often results in over- or underestimating product life. Acceleration factors must be determined based on equivalent amounts of measureable product change between the test and service environment at multiple points and for each parameter, such as EVA yellowing. Historically, experience in accelerated testing has usually shown an inverse relation between test acceleration and field correlation, i.e., "highly" accelerated (a relative term) tests typically show low correlation and therefore predictive ability. In general, the more highly accelerated a test, the greater the lack of correlation with field results.

TESTING IN OTHER INDUSTRIES

Other industries such as aerospace, electronics, and automotive systems have developed strong durability and reliability testing methodologies, although failures still occur. Most of these programs rely on strong physics-of-failure (or chemistry-of-failure) principles. This consists of robust root cause failure analyses and determination of cause and effect failure mechanisms and the variable factors that make them appear to be irregular events. The effort combines material science, physics, and chemistry with statistics, variation theory, and probabilistic mechanics (McLeish, 2012). As noted earlier, the PV industry is just beginning to understand some of the physics-of-failure mechanisms of modules needed to evolve beyond empirical test development.

The military requires durable and reliable products. Since the early 1970s, the U.S. Department of Defense and the North Atlantic Treaty Organization have been developing improved laboratory tests and test methodologies. MIL STD 810G (DOD, 2008), now in its seventh major revision, is often used for commercial products as well. It addresses a broad range of global environmental and use stress conditions. The method does not impose design or test specifications, but rather describes the environmental tailoring process that results in realistic materiel designs and test methods based on system performance requirements. Figure 23 is a simplification of the key test concepts and Figures 24 and 25 illustrate some of the environmental and service use stresses that may need to be considered. The 810G document details the factors that must weighed when designing an appropriate durability/reliability test methodology. This may serve as a valuable template for the PV industry.

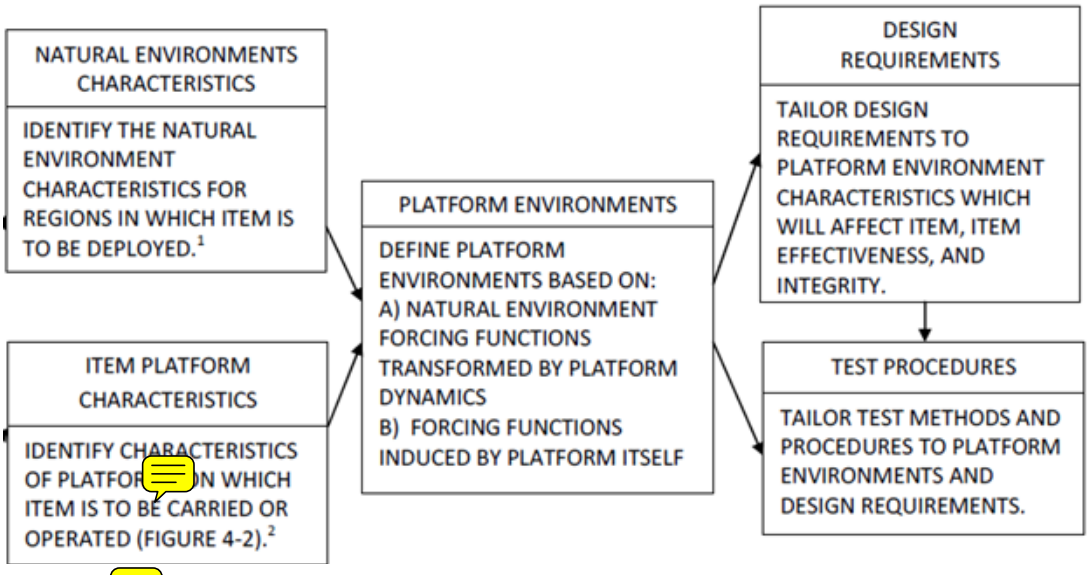


Figure 23: MIL STD 810G test tailoring considerations overview (DOD, 2008).

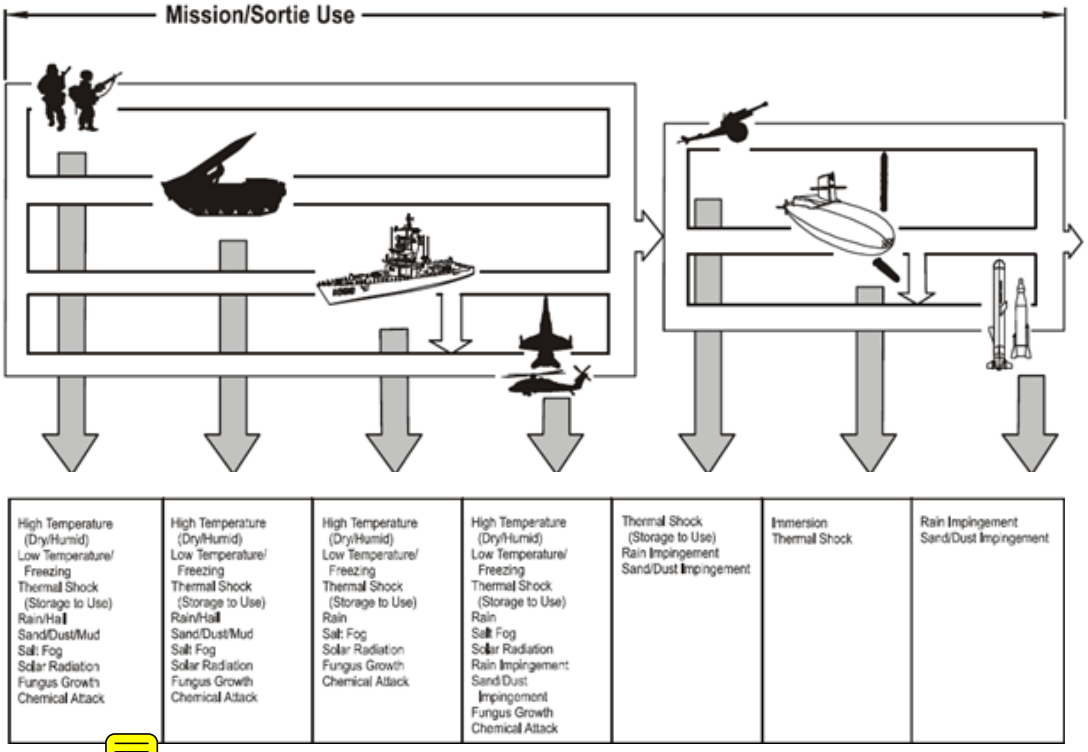


Figure 24. MIL STD 810 example of natural stresses to be considered in test design (DOD, 2008).

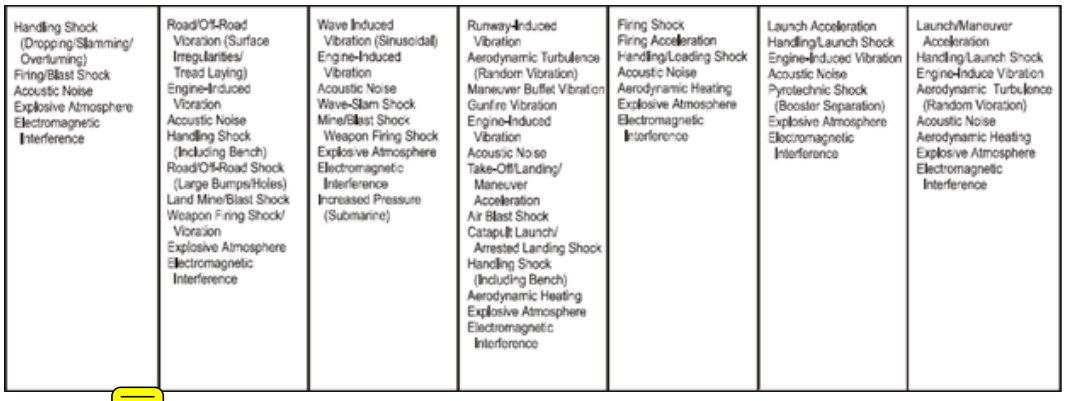


Figure 25. MIL STD 810 example of use-induced stresses to be considered in test design (DOD, 2008).

For PV modules, Kurtz et al. (Kurtz et al., 2011) provide guidance regarding the types of stresses to be considered for durability testing (Figures 26, 27), similar to the MIL STD 810 required approach.

Stress	Rating system	Accelerated test	Environmental definition
Voltage	Numeric value for maximum system voltage	As per IEC 61215 [6], or revised to be applied during damp heat	System voltage
Temperature	Class Hottest, Hot, Warm, Cool	Damp heat, possibly with voltage bias applied	Use Arrhenius behavior and create maps for rack and roof mounting
Thermal cycling	Class A, B	Thermal cycling as per IEC 61215 [6], but two levels of 200 or 500 cycles	Thermal cycling is greater for partly cloudy environments, because variable irradiance causes frequent changes in module temperature
Humidity	Class Humid, Dry	Damp heat, possibly with voltage applied	Average humidity; make map
Snow	Numeric rating for kg of static load	IEC 61215 [6] static load test	Snow load from local building code
Salt spray	Numeric severity rating	Existing IEC test (edition 2) [7]	Distance from ocean
Hail	Numeric rating for size of hail ball	Current default is 25 mm; method as in 61215 [6]	Size of hail balls experienced locally
UV	Class A, B	Use UV component test being drafted by WG2	Class A indicates high-altitude or high-irradiance site
Wind	Numeric rating for maximum wind gust	Combination of dynamic load test and vibration	Maximum wind speed seen during gusts
Transportation	Rough/Smooth	Vibration	Truck on paved and unpaved roads, train, etc.
Farmland	Pass/Fail	Use ammonia test drafted by WG2	Ammonia in agricultural area

Figure 26. Typical stresses encountered by PV modules and proposed system for rating modules (Kurtz et al., 2011). Note that IEC = International Electrotechnical Commission, UV = ultraviolet, and WG2 = IEC TC 82 Working Group 2.

Type of failure/degradation	Related stresses	Priority
Broken interconnects, solder bond failures	Thermal cycling, mechanical	First
Broken glass; structural failures	Mechanical	First
Corrosion, including electrochemical corrosion; corrosion leading to loss of grounding	Humidity, heat, bias V, dry/wet high pot	First
Hot spots	Shading	First or second
Broken cells	Thermal cycling, vibration, mechanical	Second
Delamination and/or loss of elastomeric properties of encapsulant	Humidity, heat, humidity-freeze, UV, dry/wet high pot	Second
Encapsulant discoloration	UV, heat	Second
Junction box and module connection failures	Thermal cycling, humidity, heat, humidity-freeze	Second
Bypass diode failure	Heat (applied to diodes)	Second
Open circuiting leading to arcing	Thermal cycling	Second
Ground fault from backsheet degradation	UV	Second
Ground faults	Dry/wet high pot	Second

Figure 27. Partial list of failure or degradation mechanisms and the related stresses (Kurtz et al., 2011). Note that UV = ultraviolet.

SERVICE LIFE ASSESSMENT AND SERVICE LIFE PREDICTION

The fundamental principles of true service life prediction (SLP) are well accepted in the testing community. The fundamental concepts have been well documented but fully implemented only for a relatively limited number of materials and products. The methodology has been implemented and reported most notably by Fischer (Fischer, Ketola (Ketola, 2007), and Burns (Burns, 2012) at 3M Company and by Martin (Martin, Saunders, Floyd, &Wineburg, 1994), White (White, Huntson, & Tan, 2012), and Chin (Chin, Byrd, Gu, & White, 2000) at the U.S. National Institute for Science and Technology, to name only a few. Czanderna and Jorgensen (Czanderna & Jorgensen, 1997) reported on applying this approach to PV lifetime prediction.

SLP is a methodology for estimating the functional life of a product in service by mathematical modeling of degradation and time-to-failure as a function of the cumulative effects of the external and use stresses. The service life of a material product or system can be defined as the time required for any critical functional properties to degrade to the minimum acceptable level required for the application. For PV, this minimum is often defined in terms of the maximum allowed drop in output power.

Burns (Burns, 2012) explains that there is a key conceptual difference between SLP tests and those of the current IEC tests or those protocols based on extending them. ALT is a general methodology to evaluate the robustness of a specific product design by forcing failure using very high stresses, often in combinations not possible in the real world. It assumes that survival under exceptionally high stress can directly predict service life. Meeker (Meeker, 1998) and Escobar (Escobar & Meeker, 2006; Escobar & Meeker, 2009) have further commented on the limitations of and proper statistical design of accelerated tests and the analysis of results. As noted by Wohlgemuth (Wohlgemuth, 2013), the IEC 61215 ALT tests have demonstrated the ability to duplicate one or more field observed failure modes.

SLP and ALT require that the accelerated testing reproduce the same failure modes and degradation pathways encountered in service. True SLP requires that the test stresses correlate directly with the in-service climatic stresses. By relating the same failure modes arising from the same degradation pathways, SLP is capable of providing a quantitative lifetime estimate for any location given the corresponding data. However, ALT provides only information on the ability of a system to survive severe stress, which may or may not be encountered in actual use.

Burns (Burns, 2012) identifies the fundamental process steps required in SLP methodology (Figure 28).

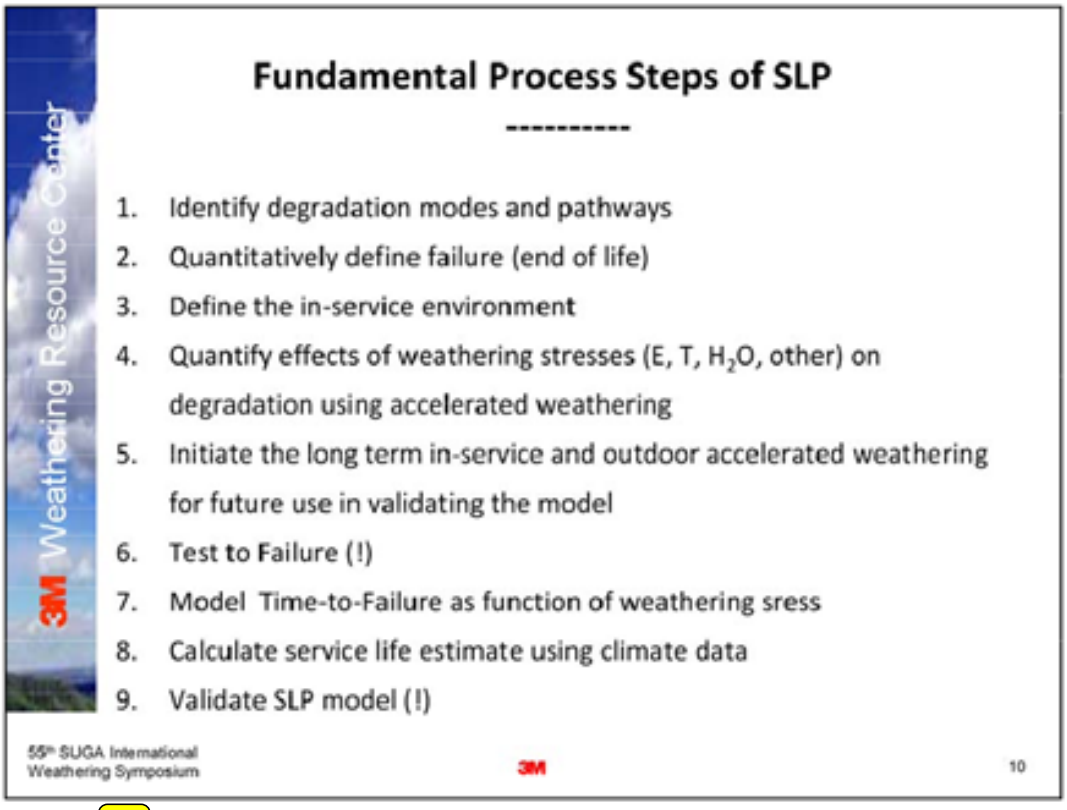


Figure 28. Steps in SLP methodology as implemented by 3M Company (Burns, 2012). Note that SLP = service life prediction.

It must be noted that this process requires rigorous discipline and detailed knowledge regarding all degradation mechanisms. At present, full SLP is beyond reach, given the multiple degradation mechanisms, complex laminate structure, and varied use climates of PV modules. In addition, there may be failure modes that have not yet been identified. Nonetheless, the methodology has direct application to all durability/reliability test schemes—environmental and use stresses must be quantified and realistic, the degradation mechanisms must correlate to field use, and the test results and models used must be validated with real time service exposures.

TEST METHOD VALIDATION

Regardless of the specific test methodology used, such as those described in this report, a fundamental requirement is that each individual test and test program must be validated to be of any practical use. This presents the industry with a fundamental and significant dilemma. As noted previously, testing must move beyond the current levels of basic qualification. Despite the significant progress in testing that is being made at the research level, there are several hindrances to developing a thorough test standard, including:

- uncertain knowledge of all longer term failure mechanisms for current product materials and designs;
- lack of 25-year field history for many current product designs (may require real time testing, but we can't wait 25 years);
- different degradation rates and failure modes for various module technologies and designs;
- different tests or test parameters may be required for individual climates;
- need for much longer test times due to the practical limits of test acceleration;
- need for multiple combined stress delivery for better simulation of the service and use environments;
- correlation must be established, i.e., same physics of failure(s) between test and field;
- apparatus limitations of current and proposed tests (technology, capacity, expense);
- need for better statistics (i.e., larger sample populations); and
- lack of comprehensive validated transfer models relating test to field results.

Current field demonstration tests and some known field history, at least for c-Si modules, may provide useful information if the data is made available.

As Köhl (Köhl, 2011a) aptly notes, the question from a pragmatic point of view becomes "Is it possible to design accelerated service life tests for PV modules?". He goes on to provide a generally practical and implementable approach, though it stops short of what is required for true validation.

First he starts with several "assumptions":

1. only long-term wear-out degradation is considered;
2. the primary degradation factors are due to weathering;
3. the stress levels depend on local climate and installation;
4. the stress levels depend on the microclimate at the module;
5. the test samples (PV modules or components) have to be considered as a "black-box", i.e., the natural applied stresses are not dependent on PV device technology or failure modes;
6. the modeling is based on investigation of the degradation kinetics of real state-of-the-art modules and is therefore device technology dependent; and
7. a service life of 25 years should result.

Köhl points out that accelerated life test parameters must be realistically derived from multi-climate outdoor monitoring and module exposure performance over time to validate the accelerated tests. The second step is to characterize the individual module microclimates including:

1. module temperature modeled by solar irradiation, ambient temperature, and wind speed;
2. module surface humidity modeled by module and ambient temperatures and humidity;
3. UV radiation modeled from solar irradiation and spectral transmittance of laminated materials;
4. temperature cycles of module temperature;
5. leakage current as a function of voltage, module temperature, and surface humidity; and
6. salt concentration correlated with wetting/drying.

He then models the module temperature for each module type using one-year outdoor data for module temperature, solar radiation, ambient temperature, wind velocity, and solar radiation to determine module-dependent parameters followed by leakage current as a function of potential, relative humidity, and temperature.

Köhl's third step is to model the degradation processes as a function of the degradation factor using various time-transformation functions (Köhl, 2001a):

1. module temperature: Arrhenius, Eyring models;
2. module surface humidity impact: power law, time-of-wetness;
3. UV radiation: dose function, reciprocity effect;
4. module temperature cycles: Coffin-Manson;
5. potential induced degradation; and
6. salt concentration correlated with wet/dry cycles.

In step four, he determines the accelerated life test conditions, such as test time at 85°C calculated as necessary to produce the equivalent damage, based on activation energies, for the various modeled climates and module types. This is repeated for other stresses such as UV exposure, humidity, etc.

Step five involves accelerated testing (e.g. 85°C/85 % RH damp heat), using various commercial modules (c-Si were used in his study) comparing power output. From this he estimates equivalent testing times necessary to achieve 25 years in various climates to determine the climate suitability of the individual modules. However, note that acceleration factors are valid only for a specific module design, material set, and evaluation criteria.

Next Köhl uses analytical tools such as Raman spectroscopy and electroluminescence to characterize the degradation followed by numerical simulation of materials degradation, such as water vapor permeation and diffusion in the backsheet and encapsulant during the accelerated tests. Lastly, various combined multiple stress tests (within the given limits of equipment technology, capacity, etc.) are performed with the intent of iterative improvements in design. This approach comes closer to key aspects of true service life prediction methodology, but still requires many assumptions, mathematical models, and performance degradation measurements over time until failure. Further, many real-world stresses such as dynamic mechanical (i.e., wind) load and other variables have not yet been included. Still, by using accepted models for key environmental stresses, basing test parameters on actual climate and module measurements, and moving toward more realistic dynamic multiple stress tests with results verified by outdoor testing, improved module durability estimates should be achieved.

RECOMMENDATIONS FOR TEST VALIDATION

Key Requirements

To advance beyond the current situation and develop PV methods and standards leading to a comprehensive PV reliability framework that serves the needs of the stakeholders and helps ensure the viability of the industry, the community needs to work together to share knowledge and systematically develop a comprehensive approach. This effort must be made without regard to the short-term logistics of funding, implementation, or geopolitical concerns. Once identified, the individual elements of such a framework (many of which are already now being performed) can be coordinated. A roadmap can be developed and efforts directed towards a common goal. This will require several key actions:

1. Accelerated test development (in standards) must be driven by correlation with field observations. Field data must be continuously collected, analyzed, and prioritized so as to focus resources where they can make the most difference. Specific details that need to be quantified and understood include but are not limited to:
    i. intrinsic module issues that are not being detected with current tests;
    ii. environmental stress effects resulting from various climates;
    iii. system service use conditions (e.g., string size, inverter technology);
    iv. module transportation damage;
    v. module installation effects (mounting, wiring, handling); and
    vi. operation and maintenance effects (module washing, re-cabling, off-line strings).

These need to be categorized not only by type, age, and location, but also by relevant module characteristics (e.g., semiconductor technology, number and type of cells/strings, mounting configuration, cell interconnect method, encapsulant and backsheet type, power and electrical characteristics, etc.).

2. Tackling each identified failure/degradation mechanism according to how it has been prioritized in step #1, we must thoroughly understand the cause and the related stresses and use modeling based on those to estimate the testing that provides confidence that the mechanism is adequately mitigated. The common approach of simply extending the time of tests should be based on correlation with field observations and/or physics-based models. New tests that can achieve higher acceleration factors without introducing larger uncertainty in the meaning of the tests should be developed whenever possible. However, the key goal is to develop tests that can reduce the uncertainty, regardless of test time.

3. The critical climatic service environments of concern need to be accurately identified and characterized as a key input to the modeling in #2. Secondly, most modules are not standalone; the modeling done in #2 should include system-related stresses (e.g., system electrical characteristics) that can easily be neglected during module-level testing. These may or may not be adequately represented in existing tests, or may lead to combined or new tests. Including the variable stresses seen in each use environment (e.g., climate, mounting configuration, and system design) is an important step should industry wish to develop suitability ratings for specific climates or performance ratings for modules. This may result in lower module cost if modules are designed to perform in specific markets rather than the worldwide approach used for most products today.

4. Once items (2) and (3) are accomplished and implemented into test standards for the prioritized failure mechanisms, the effects of the individual climate parameters, their levels, combinations, and cycles can be investigated by tracking field results relative to the new test results. These results will serve as a continuing framework as new module materials, technologies, and designs are developed. The current lack of consistent correlation between accelerated testing and field observations slows the validation and refinement of testing procedures.

5. A systematic set of experiments to correlate accelerated and field testing of module designs that are known to be both robust and flawed could be implemented through the DOE regional test centers and/or other test laboratories to hasten the development and validation of improved test methods. The results from these tests can continue to feed the work above as all failure mechanisms are tackled.

6. In parallel with the above steps, mathematical models should be developed relating degradation rates and field failures to accelerated testing. Models must be validated against actual field performance. Further, the results of accelerated testing can then be modeled to climate stresses to estimate service life. With comprehensive models, it may be possible to estimate how changes in module materials or design may impact performance, durability, and reliability.

Short-Term Needs and Recommendations

A critical concern within the industry relates to module manufacturing QA as an ongoing process. Will changes in materials vendors or specifications, manufacturing lines or process affect product quality or performance? The first step we need to take addresses manufacturing variability to assure stakeholders that production modules are of the same quality as those from qualification testing. Current qualification testing goes a long way to providing durable products if consistently implemented. The PV-specific version of the ISO 9000 series that is being submitted for consideration by IEC TC82 WG2 is a first start. The community should discuss how this can best be implemented and whether there is a conflict of interest in audits paid for by the factory compared with audits paid for by a coalition of customers or other community organization. Models exist in other industries; one example is the Good Manufacturing Practice system used in the pharmaceutical industry (WHO, 2007).

The second step is to systematically identify those accelerated stresses that have demonstrated some degree of predictive ability, many of which are implemented in the schemes detailed in this document, to better assess module long-term durability and performance. Their use should be promoted on a voluntary basis. This will serve as a relative comparison basis until full consensus standards can be developed.

The IPVMQATF is currently the only overarching short-term global effort underway to support recommended steps 1-6, so the third step is to actively support and participate in the Task Force and its working groups (Solar ABCs, 2013).

SUMMARY

The current level of IEC design type qualification tests has served reasonably well as a basic screen for key early failure issues over the past 30 years. Extending specific tests may be effective in providing longer term wear-out and end-of life estimations. In their present form, these tests have generally proven insufficient, however, to predict either long-term service durability or lifetime. Further, current tests may not adequately detect some degradation mechanisms, particularly those that are longer term or climate-specific.

This has resulted in an effort to improve standard qualification testing to better predict long-term performance, durability, and reliability. Currently, the most common approaches are to (1) modify or extend existing IEC tests; (2) combine IEC tests in new combinations, cycles, or sequences; (3) augment IEC tests with multi-stress accelerated weathering tests on modules or materials; (4) add specific tests such as potential induced degradation to the current or "extended" IEC tests; (5) perform extended outdoor exposures in demonstration projects; and (6) move beyond existing IEC tests to a service life prediction methodology. Each level involves a different degree of knowledge and sophistication, time and effort, and cost. These must be balanced with scientific validity, rapid technology changes, and the ever changing market conditions and needs of the various stakeholders.

TamizhMani (TamizhMani, 2010; TamizhMani, 2009) describes three levels of testing (Figure 29) for PV modules: (1) current accelerated qualification tests, (2) accelerated comparative testing, and (3) true accelerated lifetime tests. Currently, the industry is at the first level of testing and standards and attempting to move to the second. The third is currently beyond the state of the art in the industry, although incremental progress is being made.

ACCELERATED AGING TESTS OF PV MODULES			
	ACCELERATED QUALIFICATION TESTING	**ACCELERATED COMPARATIVE TESTING**	**ACCELERATED LIFETIME TESTING**
Design Quality and Confidence	Minimum*	Medium**	High***
Objective	Minimum testing for reliability/durability of **specific** module **design**	Extended qualification testing to compare relative reliability/durability of **multiple designs**	Site (and configuration) specific testing or worst case site (s) testing of any **specific** module **design**
Cost and Time	Low	Medium	High
Goal	**Introduce** the specific design in the market	**Compare** (to improve/purchase/invest) multiple designs	**Predict** lifetime and/or protect warranty
Testing Protocol	Test **standards exist**	Tester defined protocols exist but a **uniform protocol is needed**	None publicly exists, if any. **Needs a comprehensive understanding on failure mechanisms, failure modes and mathematical models to develop an appropriate testing protocol**
Test requirement	**Pass/Fail** (>5% Pmax drop = Fail)	**Relative** power loss for a specific stress time or relative stress time for a specific power loss	Identify ultimate failure mode and/or **to determine/substantiate warranty period**
User	Manufacturers/ Consumers/Investors	Manufacturers/ Consumers/Investors	Manufacturers

Figure 29: Three distinct levels of accelerated PV module accelerated testing (TamizhMani, 2010).

Several efforts are underway to push testing to the second level as described above, but the results of these efforts cannot be predicted at this time. However, it is important that these efforts are productive, meaning that they produce tests and knowledge that advance the industry and serve the needs of stakeholders. However, the current semi-empirical approach is suboptimal in efficiency, and is not always rigorously validated.

The development of such tests requires understanding the science behind the observed failure modes. Existing initial qualification tests are insufficient to assure durability and reliability. As DeGraaff (DeGraaff, 2011) notes, the ". . . majority of failures can be attributed to inadequate manufacturing QA and/or not testing when materials or processes are changed." Therefore, retest requirements may need to be imposed whenever a material or design fundamentally changes, and requirements for ongoing manufacturing quality assurance will need to follow.

The experience of other industries and scientific research has resulted in a proven service life prediction methodology. Although technically difficult to implement on a large multi-component laminate structure that must last 25 years or more with little or no degradation or catastrophic premature failure or safety concerns in many different and severe climates, the effort is likely to result in improved market competiveness for PV. Such an effort would require extensive coordination, participation, and support from PV manufacturers, academia, national and other research laboratories, testing facilities, and other stakeholders. This requires a multi-step approach:

1. Establish a consolidated database of module degradation and field failures.
2. Conduct systematic review of module degradation and failure modes.
3. Characterize the key climatic service and system environmental variables.
4. Implement design of experiment to determine stress-failure interactions.
5. Execute real time testing exposures in various climates with key module technologies.
6. Establish models and transfer functions for service exposures and accelerated lab testing.
7. Establish an ongoing manufacturing quality assurance audit program.

Given market economics and other conditions, this comprehensive approach may be unlikely in the foreseeable future. However, many efforts currently underway could be more closely coordinated and aligned to support the key elements of this approach, yielding substantial improvements in the short term even if the full approach is beyond reach.

Alternatively, a more expedient short-term approach is the development of comparative module data. This approach is gaining some traction as a competitive tool, but to be effective industry-wide, it needs to be expanded, even if on a voluntary basis. This may be possible through standards requiring module manufacturers to report hard data rather than using a generic pass/fail approach. Some module manufacturers and buyers already advocate hard data reporting, and this may serve industry needs while a true SLP methodology is implemented over the next few decades.
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Thirty years from now, we can go into the field and collect statistics to convert the comparative test standard data into a more quantitative SLP. There would likely be wide variation in the data, but if the methodology applies stresses that are relevant to the use environment, it should be possible to use those results to make statistical predictions about how long modules will last in each location as a function of the comparative test results.

The practice of effectively using a test standard as the basis of a worldwide experiment could be practical. This may be a way to accomplish "extensive coordination" without the huge budget required to have researchers execute a similar project. Similar to distinguishing "reliability" from "durability" testing, moving studies out of carefully controlled test fields and turning the whole world into a laboratory may be way to finally answer the question "How long will my module last?" and connect with the real needs of the customer.

ACRONYMS

a-Si	amorphous silicon
AC	alternating current
ALT	accelerated life testing
c-Si	monocrystalline silicon
DC	direct current
DOE	U.S. Department of Energy
DH	damp heat
EC	European Commission
EL	electroluminescence
EVA	ethylene vinyl acetate
HF	humidity freeze
Hipot	high potential
IEC	International Electrotechnical Commission
IPVMQATF	International PV Module Quality Assurance Task Force
~~IPVMQAF~~	~~International PV Module Quality Assurance Forum~~
IQT	interim qualification test
IR	infrared
IV	current-voltage
JPL	Jet Propulsion Laboratory
JRC	EC's Joint Research Centre
LID	light-induced degradation
LST	long-term sequential test
MPP	maximum power point
NREL	National Renewable Energy Laboratory
Pa	Pascal
PID	potential induced degradation
PV	photovoltaic
QA	quality assurance
RH	relative humidity
SERI	Solar Energy Research Institute
Si	silicon
SLP	service life prediction
TCO	transparent conducting oxide
TC	thermal cycles
TTF	test to failure
UV	ultraviolet
WG	working group

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Impacts on Photovoltaic Installations of Changes to the 2012 International Codes

A Solar ABCs White Paper

May 2011

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May 2011

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Table of Contents

Executive Summary iii

Disclaimer iv

Solar ABCs iv

Acknowledgement iv

1. Introduction and Purpose 1

2. Background on the Codes 1

3. Building-Integrated Photovoltaic Requirements 2

4. Rack-Mounted Photovoltaic Requirements 3

5. About the Organizations 6

Appendix: 2012 Code Changes 7

Acronyms 9

Executive Summary

The purpose of this white paper is to provide an overview of changes related to photovoltaic (PV) installations in the 2012 International Building Code (IBC) and International Residential Code (IRC). These codes include requirements for building-integrated photovoltaic (BIPV) products and rack-mounted PV products. For each of these products, the codes include requirements for installation, materials, wind resistance, and fire classification. This information is intended to assist code officials, solar installers, and roofing contractors as they interpret and use these codes.

This white paper documents changes found in three sections of the 2012 IBC and two sections of the 2012 IRC:

- IBC Section 1505—Fire Classification,
- IBC Section 1507 and IRC Section R905—Requirements for Roof Coverings, and
- IBC Section 1509 and IRC Section M2302—Rooftop Structures.

Important observations include:

- The requirements are different for BIPV systems and rack-mounted PV systems.
- Until a new PV system fire classification test is finalized and adopted, Section 1509.7.2 of the IBC, as written, may be difficult to apply.
- IBC Section 1509.7.1 prescribes the use of components and cladding requirements of current codes and standards as the basis for calculating wind loads on PV arrays. This provides helpful guidance for wind engineering calculations, but may not provide results consistent with other methods accepted and used today.

You can order the 2012 IBC and 2012 IRC at: www.iccsafe.org/Store/

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Solar America Board for Codes and Standards

The Solar America Board for Codes and Standards (Solar ABCs) is a collaborative effort among experts to formally gather and prioritize input from the broad spectrum of solar photovoltaic stakeholders including policy makers, manufacturers, installers, and consumers resulting in coordinated recommendations to codes and standards making bodies for existing and new solar technologies. The U.S. Department of Energy funds Solar ABCs as part of its commitment to facilitate wide-spread adoption of safe, reliable, and cost-effective solar technologies.

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Acknowledgement

This white paper was prepared by a collaborative team effort of diverse stakeholders. Solar ABCs gratefully acknowledges the contributions in preparing this document from Stephen Barkaszi, Florida Solar Energy Center; Christine Covington, Solar Energy Industries Association; Mark Graham, National Roofing Contractors Association; Dennis Grubb, Orange County Fire Authority; Colleen O'Brien, BEW Engineering; Lorraine Ross, Intech Consulting; and John Taecker, Underwriters Laboratories.

This material is based upon work supported by the U.S. Department of Energy under Award Number DE-FC36-07GO17034.

1. Introduction and Purpose

The purpose of this white paper is to provide information about changes related to photovoltaic (PV) installations in the 2012 International Building Code (IBC) and the 2012 International Residential Code (IRC). These codes include fire classification, wind resistance, installation, and materials requirements for building-integrated photovoltaic (BIPV) and rack-mounted PV products. This information is intended to assist code officials, solar installers, and roofing contractors as they interpret and use these codes.

This white paper documents changes found in three sections of the 2012 IBC and two sections of the 2012 IRC:

- IBC Section 1505—Fire Classification,
- IBC Section 1507 and IRC Section R905—Requirements for Roof Coverings, and
- IBC Section 1509 and IRC Section M2302—Rooftop Structures.

Solar ABCs has published a separate document on the changes to the International Fire Code (IFC). The 2012 IFC includes requirements for PV installations, and the Solar ABCs report describes the California solar installation guidelines and the similar 2012 IFC requirements. This report is available at: www.solarabcs.org/fireguideline

Section 2 of this document provides background on building codes, and sections 3 and 4 note the relevant sections of the 2012 IBC and IRC codes for BIPV and rack-mounted PV installations. The appendix cites the changes in the 2012 codes related to PV installations. We include the code language in red.

2. Background on the Codes

The International Code Council (ICC) develops a family of model codes, many of which are widely adopted across the United States. The ICC updates its model codes every three years and will publish the 2012 editions of the codes in the spring of 2011. Information about the ICC code development process is available at: www.iccsafe.org/cs/codes/Pages/default.aspx

IBC applies to all buildings and structures except those covered by IRC (see IBC 101.2, which addresses the scope of IBC). IRC applies to detached one- and two-family dwellings and townhouses not more than three stories above grade in height (IRC R101.2). Both IBC and IRC apply to the construction, alteration, movement, enlargement, replacement, repair, equipment, use and occupancy, location, maintenance, removal, and demolition of every building or structure or any appurtenance connected or attached to such buildings or structures.

Chapter 27 of the IBC and Part V of the IRC refer to the National Fire Protection Association (NFPA) 70, National Electrical Code. PV systems must comply with Article 690 and other requirements in NFPA 70.

The ICC's International Fire Code (IFC) establishes the minimum requirements consistent with nationally recognized good practice for providing a reasonable level of life safety and property protection from the hazards of fire, explosion, or dangerous conditions in new and existing buildings, structures, and premises and to provide safety to fire fighters and emergency responders during emergency operations (IFC 101.2).

State and local jurisdictions have adopted the IBC throughout most of the United States. Many jurisdictions have also adopted the IRC and the IFC. Some jurisdictions adopt the IBC and use that code for residential structures as well. Some jurisdictions adopt one or more of these codes and incorporate local amendments. In addition, jurisdictions take different amounts of time to adopt new editions of the code. To determine the requirements in a specific jurisdiction requires knowledge of which editions of which codes have been adopted and what if any local amendments have been added to the code(s).

3. Building-Integrated Photovoltaic Requirements

BIPV systems replace conventional materials in a building envelope—typically roof or façade finish materials—with a product that performs the function of the conventional material and generates electricity. IBC references PV shingle roofing products that generate electricity and serve as the roof covering of the structure as well as PV systems that are adhered or attached to the roof covering, such as thin film PV modules permanently adhered to metal roofing.

Installation

IBC Section 1507.17.2 (IRC R905.16.2) details the installation requirements for PV modules/shingles used as roof coverings. For PV systems that are adhered or attached to the roof covering, use the relevant code section from IBC 1507 (IRC R905) for the roof covering.

2012 code language:

IBC 1507.17.2 (IRC R905.16.2) Attachment. Photovoltaic modules/shingles shall be attached in accordance with the manufacturer's installation instructions.

Materials

IBC Section 1507.17.1 (IRC R905.16.1) details the material requirements for PV modules/shingles used as roof coverings. For PV systems that are adhered or attached to the roof covering, use the relevant code section from IBC 1507 (IRC R905) for the roof covering.

2012 code language:

IBC 1507.17.1 (IRC R905.16.2) Material standards. Photovoltaic modules/shingles shall be listed and labeled in accordance with UL1703.

Wind Resistance

IBC Section 1507.17.3 (IRC R905.16.3) details the wind resistance requirements for PV modules/shingles used as roof coverings. For PV systems adhered or attached to the roof covering, use the relevant code section from IBC 1507 (IRC R905) for the roof covering.

2012 code language:

IBC 1507.17.3 (IRC R905.16.3) Wind resistance. Photovoltaic modules/shingles shall be tested in accordance with procedures and acceptance criteria in ASTM D 3161. Photovoltaic modules/shingles shall comply with the classification requirements of Table 1507.2.7.1(2) for the appropriate maximum nominal design wind speed. Photovoltaic modules/shingle packaging shall bear a label to indicate compliance with the procedures in ASTM D 3161 and the required classification from Table 1507.2.7.1(2).

Fire Classification

IBC Section 1505.8 requires that all BIPV modules be tested and labeled as Class A, B, or C in accordance with the methods of ASTM 108 or Underwriters Laboratories® (UL) 790, *Standard Test Methods for Fire Tests of Roof Coverings*. The fire classification rating must meet the requirements in Section 1505.

2012 code language:

IBC 1505.8 Photovoltaic systems. Rooftop installed photovoltaic systems that are adhered or attached to the roof covering or photovoltaic modules/shingles installed as roof coverings shall be labeled to identify their fire classification in accordance with the testing required in Section 1505.1.

4. Rack-Mounted Photovoltaic Requirements

IBC Section 1509 and IRC Section M2302 apply to rooftop structures, and the requirements of these sections apply to PV systems mounted over the roof assembly. PV systems mounted on racks over the roof are a common example of this system.

The requirements in the specific IBC and IRC sections include:

Installation

Code Section	Requirement
IBC Section 1509.7.3	Installation in accordance with manufacturer's installation instructions.
IRC Section M2302.2	Installation in accordance with manufacturer's instructions and NFPA 70 (National Electrical Code).
IRC Section M2302.2.1	The roof shall be constructed to support the loads imposed by the PV modules.
IRC Section M2302.2.2	Roof and wall penetrations shall be flashed and sealed in accordance with Chapter 9 of the IRC.
IRC Section M2302.2.3	Ground-mounted PV systems shall be installed in accordance with manufacturer's instructions.

2012 IBC code language:

1509.7.3 Installation. Rooftop mounted photovoltaic systems shall be installed in accordance with the manufacturer's installation instructions.

2012 IRC code language:

M2302.2 Requirements. The installation, inspection, maintenance, repair and replacement of photovoltaic systems and all system components shall comply with the manufacturer's instructions, Sections M2302.2.1 through M2302.2.3 and NFPA 70.

M2302.2.1 Roof-mounted panels and modules. Where photovoltaic panels and modules are installed on roofs, the roof shall be constructed to support the loads imposed by such modules. Roof-mounted photovoltaic panels and modules that serve as a roof covering shall conform to the requirements for roof coverings in Chapter 9. Where mounted on or above the roof coverings, the photovoltaic panels and modules and supporting structure shall be constructed of noncombustible materials or fire-retardant-treated wood equivalent to that required for the roof construction.

M2302.2.2 Roof and wall penetrations. Roof and wall penetrations shall be flashed and sealed in accordance with Chapter 9 to prevent entry of water, rodents and insects.

M2302.2.3 Ground-mounted panels and modules. Ground-mounted panels and modules shall be installed in accordance with the manufacturer's installation instructions.

Materials

IBC Section 1509.7.4 and IRC Section M2302.3 require PV panels and modules to be listed and labeled in accordance with UL 1703. IRC Section M2302.4 requires inverters to be listed and labeled in accordance with UL 1741.

2012 IBC Code language:

1509.7.4 Photovoltaic panels and modules. Photovoltaic panels and modules mounted on top of a roof shall be listed and labeled in accordance with UL 1703 and shall be installed in accordance with the manufacturer's installation instructions.

2012 IRC Code language:

M2302.3 Photovoltaic panels and modules. Photovoltaic panels and modules shall be listed and labeled in accordance with UL 1703.

M2302.4 Inverters. Inverters shall be listed and labeled in accordance with UL 1741. Systems connected to the utility grid shall use inverters listed for utility interaction.

Wind Resistance

IBC Section 1509.7.1 establishes criteria for calculating the minimum design loads for rack-mounted PV systems on roofs. The code specifies that the wind loads shall be calculated using the method prescribed for components and cladding (C&C) using an effective wind area based on the dimensions of a single unit. This provides guidance for wind load engineering calculations, which were not available previously for PV systems on roofs.

The procedure called for by Section 1509.7.1 is different from the procedure described in Solar ABCs report, *Wind Load Calculations for PV Arrays*, which recommends using the main wind-force resisting systems (MWFRS) as the design parameter. The Solar ABCs report is available to download at:
www.solarabcs.org/about/publications/reports/wind-load/index.html

There are pros and cons associated with the use of each of these methods. By definition, MWFRS is an assemblage of structural elements assigned to provide support and stability for the overall structure and receive and transmit wind loading forces from more than one surface. In the American Society of Civil Engineers' *Minimum Design Loads for Buildings and Other Structures* (ASCE-7), C&C are defined as elements of the building envelope that do not qualify as part of the MWFRS.

Although many BIPV or flush-mounted modules meet the C&C criteria, the Solar ABCs task team determined that the common method of mounting PV arrays on roofs using a racking system meets the definition of MWFRS. Specifically, the modules and mounting hardware are considered to be a structural system because all the hardware is above the roof surface and forces are applied to more than one surface of the system. Rack-mounted PV array modules and hardware are more than a surface-covering element such as a shingle or siding.

The IBC language states that the effective wind area should be based on the dimensions of a single unit frame. For a large rack, this method may be very conservative, and result in over-estimated wind forces. This small effective area may be appropriate for modules mounted at the perimeter of an array field, but interior modules can be subject to significantly lower forces. Using the single unit as the effective wind area may be appropriate until testing can establish the distribution of wind forces.

The IBC method and the Solar ABCs method each recommend using a different, existing element of current codes and standards as the basis for the wind load calculations. In the long term, the preferred solution to this discrepancy is not to analyze PV systems in the same way as other dissimilar components, but rather to develop wind load guidelines specifically for PV modules and arrays. Solar ABCs is currently conducting wind tunnel testing to develop performance-related design parameters for PV systems. Once developed, these design requirements can be incorporated into the IBC and ASCE standards.

The IRC does not include wind resistance requirements.

2012 IBC Code language:

1509.7.1 Wind resistance. Rooftop mounted photovoltaic systems shall be designed for wind loads for component and cladding in accordance with Chapter 16 using an effective wind area based on the dimensions of a single unit frame.

Fire Classification

IBC Section 1509.7.2 includes requirements for fire classification of rooftop mounted PV *systems.* IRC Section M2302.2.1 includes requirements for noncombustible or fire-retardant materials. A key objective of the code requirement is that the installation of PV does not diminish the minimum fire safety requirements for the roof. Roof systems have long received fire classification ratings. These ratings are based on the ability to prevent a fire from penetrating through the roof and the ability to minimize the spread of a fire along the roof surface.

The requirements of the 2012 IBC 1509.7.2 will need careful examination in their application. The language of this section states that the fire classification of PV *systems* must match the minimum fire classification of the roof assembly over which they are mounted as required in Section 1505. With any rooftop structure, the structure should not degrade the fire resistance properties of the roof, so as not to place the structure and its inhabitants at an unanticipated risk. However, straightforward implementation of this requirement is not possible.

PV *modules* are a component of a rooftop mounted PV system and, although PV *modules* can receive a fire classification rating (in accordance with ANSI/UL 1703), there is presently no American National Standard Institute (ANSI) fire classification test or rating for a PV *system*. Similarly, there is no ANSI fire classification test for systems that include the PV array and the roof assembly. Thus, as currently written, Section 1509.7.2 refers to the fire classification rating of a system, and this exact approach is not yet available.

In the absence of a PV *system* rating, it may seem appropriate to use the PV *module* fire classification rating in order to ensure the desired result, which is the preservation of the roof assembly's original fire classification. However, simply using the PV module fire classification rating may not provide the desired result in all cases.

In 2008 and 2009, rigorous testing by UL and Solar ABCs revealed that the performance of a *system*—which includes PV modules on standoff mounted racks—exposed to fire or flame is not the same as that of a *module* alone. Currently, modules receive a fire classification rating based on testing the module alone, not as part of a PV system. The results of these tests show that actual performance of a rack-mounted PV system exposed to fire or flame is strongly dependent on the mounting geometry of the PV array and properties of the components that make up the specific module type. (A summary of this research is published in a Solar ABCs report available at: www.solarabcs.org/about/publications/reports/flammability-testing/index.html)

As a result of this testing and in consideration of the current requirements of IBC Section 1509.7.2, Solar ABCs, UL, and an ANSI/UL 1703 Standards Technical Panel (STP) working group are actively developing a new test methodology. This is being done in close association with a working group composed of representatives from the PV industry, the roofing industry, standards development, the building and fire enforcement community, and government laboratory experts. The work product of this effort will be presented immediately to the full STP for UL 1703 for vetting and, ultimately, adoption. If adopted, this new test will be applicable to PV *systems* and will provide the valid, ANSI standard fire classification rating needed for compliance in the execution of the requirements of Section 1509.7.2.

Until a PV system fire classification test is finalized and adopted, Section 1509.7.2, as written, cannot be easily applied. Expert stakeholders are actively working on this issue, Solar ABCs and UL are conducting further research, and UL STPs are revising UL 1703.

2012 IBC Code language:

1509.7.2 Fire classification. Rooftop mounted photovoltaic systems shall have the same fire classification as the roof assembly required by Section 1505.

2012 IRC Code language:

M2302.2.1 Roof-mounted panels and modules. Where photovoltaic panels and modules are installed on roofs, the roof shall be constructed to support the loads imposed by such modules. Roof-mounted photovoltaic panels and modules that serve as a roof covering shall conform to the requirements for roof coverings in Chapter 9. Where mounted on or above the roof coverings, the photovoltaic panels and modules and supporting structure shall be constructed of noncombustible materials or fire-retardant-treated wood equivalent to that required for the roof construction.

5. About the Organizations

Solar America Board for Codes and Standards

The Solar America Board for Codes and Standards (Solar ABCs) is a collaborative effort among experts to formally gather and prioritize input from the broad spectrum of solar PV stakeholders including policy makers, manufacturers, installers, and consumers resulting in coordinated recommendations to codes and standards making bodies for existing and new solar technologies. The U.S. Department of Energy funds Solar ABCs as part of its commitment to facilitate widespread adoption of safe, reliable, and cost-effective solar technologies.

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Website: www.ul.com

Appendix: 2012 Code Changes

Changes to IBC Section 1505

The 2012 IBC contains one change in Section 1505 that impacts PV installations. The modified provisions read:

1505.8 Photovoltaic systems. Rooftop installed photovoltaic systems that are adhered or attached to the roof covering or photovoltaic modules/shingles installed as roof coverings shall be labeled to identify their fire classification in accordance with the testing required in Section 1505.1.

Changes to IBC Section 1507

The 2012 IBC contains several changes in Section 1507 that impact PV installations. The same language is used in IRC Section R905.16. The modified provisions read:

1507.17 Photovoltaic modules/shingles. The installation of photovoltaic modules/shingles shall comply with the provisions of this section.

1507.17.1 Material standards. Photovoltaic modules/shingles shall be listed and labeled in accordance with UL 1703.

1507.17.2 Attachment. Photovoltaic modules/shingles shall be attached in accordance with the manufacturer's installation instructions.

1507.17.3 Wind resistance. Photovoltaic modules/shingles shall be tested in accordance with procedures and acceptance criteria in ASTM D 3161. Photovoltaic modules/shingles shall comply with the classification requirements of Table 1507.2.7.1(2) for the appropriate maximum nominal design wind speed. Photovoltaic modules/shingle packaging shall bear a label to indicate compliance with the procedures in ASTM D 3161 and the required classification from Table 1507.2.7.1(2).

Changes to IBC Section 1509

The 2012 IBC contains several changes in Section 1509 that impact PV installations. The modified provisions read:

1509.7 Photovoltaic systems. Rooftop mounted photovoltaic systems shall be designed in accordance with this section.

1509.7.1 Wind resistance. Rooftop mounted photovoltaic systems shall be designed for wind loads for component and cladding in accordance with Chapter 16 using an effective wind area based on the dimensions of a single unit frame.

1509.7.2 Fire classification. Rooftop mounted photovoltaic systems shall have the same fire classification as the roof assembly required by Section 1505.

1509.7.3 Installation. Rooftop mounted photovoltaic systems shall be installed in accordance with the manufacturer's installation instructions.

1509.7.4 Photovoltaic panels and modules. Photovoltaic panels and modules mounted on top of a roof shall be listed and labeled in accordance with UL 1703 and shall be installed in accordance with the manufacturer's installation instructions.

Changes to IRC Section M2302

The 2012 IRC contains a new Section M2302 that impacts PV installations.

Photovoltaic Solar Energy Systems

M2302.1 General. This section provides for the design, construction, installation, alteration and repair of photovoltaic equipment and systems.

M2302.2 Requirements. The installation, inspection, maintenance, repair and replacement of photovoltaic systems and all system components shall comply with the manufacturer's instructions, Sections M2302.2.1 through M2302.2.3 and NFPA 70.

M2302.2.1 Roof-mounted panels and modules. Where photovoltaic panels and modules are installed on roofs, the roof shall be constructed to support the loads imposed by such modules. Roof-mounted photovoltaic panels and modules that serve as a roof covering shall conform to the requirements for roof coverings in Chapter 9. Where mounted on or above the roof coverings, the photovoltaic panels and modules and supporting structure shall be constructed of noncombustible materials or fire-retardant-treated wood equivalent to that required for the roof construction.

M2302.2.2 Roof and wall penetrations. Roof and wall penetrations shall be flashed and sealed in accordance with Chapter 9 to prevent entry of water, rodents and insects.

M2302.2.3 Ground-mounted panels and modules. Ground-mounted panels and modules shall be installed in accordance with the manufacturer's installation instructions.

M2302.3 Photovoltaic panels and modules. Photovoltaic panels and modules shall be listed and labeled in accordance with UL 1703

M2302.4 Inverters. Inverters shall be listed and labeled in accordance with UL 1741. Systems connected to the utility grid shall use inverters listed for utility interaction.

ACRONYMS

ANSI	American National Standard Institute
ASCE	American Society of Civil Engineers
BIPV	building-integrated photovoltaic
C&C	components and cladding
IBC	International Building Code
IFC	International Fire Code
IRC	International Residential Code
MWFRS	main wind-force resisting systems
NFPA	National Fire Protection Association
PV	photovoltaic
Solar ABCs	Solar America Board for Codes and Standards
STP	Standards Technical Panel

Understanding the CAL FIRE

Solar Photovoltaic Installation Guideline

Prepared by:

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Brooks Engineering

Solar America Board for Codes and Standards

www.solarabcs.org

Sustainable, Multi-Segment Market Design

for Distributed Solar Photovoltaics

Prepared by
Interstate Renewable Energy Council

Kevin T. Fox,
Keyes & Fox, LLP

Laurel Varnado,
North Carolina Solar Center

Solar America Board for Codes and Standards

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Solar America Board for Codes and Standards Report

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October 2010

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Executive Summary

There are two important and distinct markets for solar photovoltaic (PV) investment—a retail market and a wholesale market. In areas of the United States that are experiencing the most significant growth in PV investment, state and local policy makers have taken important differences between retail and wholesale markets into account in establishing policies that promote growth in both of these market segments. This multi-segment approach allows interrelated policies to function best in their designated roles, extending the benefits of PV to the widest possible range of participants.

Retail market policies include net metering and meter aggregation policies; community solar policies such as joint billing, virtual net metering, and joint ownership; and PV incentive programs. These successful retail policies allow retail customers to generate and use PV power to serve their electric power needs with minimal effort. They also provide easy enrollment, have minimal ongoing obligations and no hidden fees, and avoid the creation of taxable benefits and regulatory requirements that can often accompany participation in wholesale market programs.

Wholesale market policies include avoided cost pricing mechanisms, renewable energy credit (REC) markets, feed-in tariffs (FITs), and market-based procurement mechanisms such as auctions and requests for proposals (RFPs). Successful wholesale policies create opportunities to optimally locate distributed PV projects in a way that maximizes benefits to ratepayers while minimizing cost. An important consideration in establishing wholesale market policies is minimizing costs to ratepayers who pay for utility procurement decisions. To address this concern, successful wholesale programs create sustainable markets that avoid boom-bust development cycles and promote and capture cost reductions through market-responsive pricing mechanisms.

This paper discusses the important differences between retail and wholesale PV markets and provides examples of policies that have been implemented in the United States in both of these markets. The Retail Market Policies section discusses policies that enable end-use retail electric customers to invest in PV systems to meet some or all of their electricity needs. The Wholesale Market Policies section, by comparison, discusses policies that enable small and medium scale project developers to develop distributed generating facilities that will serve nearby retail electric utility load. Building upon those sections, a final Recommendations section examines the ways in which decision-makers in leading U.S. markets for PV market growth are implementing a range of interrelated policies that can support sustainable, multi-segment market growth for distributed PV.

Author Biographies

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Kevin Fox, co-founder of Keyes & Fox LLP, has developed a highly specialized legal practice that focuses on assisting clients with achieving regulatory goals and objectives, in particular energy market transformation efforts that facilitate growth in distributed energy resource markets. His firm has represented clients before more than 35 state public utility commissions. He received a J.D. from the University of California, Berkeley, and a B.S. from the University of California, Davis.

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Solar America Board For Codes And Standards

The Solar America Board for Codes and Standards (Solar ABCs) provides an effective venue for all solar stakeholders. A collaboration of experts formally gathers and prioritizes input from groups such as policy makers, manufacturers, installers, and large- and small-scale consumers to make balanced recommendations to codes and standards organizations for existing and new solar technologies. The U.S. Department of Energy funds Solar ABCs as part of its commitment to facilitate widespread adoption of safe, reliable, and cost-effective solar technologies.

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Acknowledgements

This material is based upon work supported by the Department of Energy under Award Number DE-FC36-07GO17034.

The authors would like to thank Thad Culley, Adam Browning, Brad Klein, Mike Taylor, Michael Coddington, Sarah Kurtz, Howard Barikmo, Karlynn Cory, Charlie Hemmeline, Rusty Haynes, Jason Keyes, Joe Wiedman, Chris Cook, and Sky Stanfield for reviewing a draft of this report and providing critical feedback.

Table of Contents

DISCLAIMER ii
EXECUTIVE SUMMARY iii
AUTHOR BIOGRAPHIES v
INTRODUCTION 1
RETAIL MARKET POLICIES 5
1. NET METERING 5
a. Carrying Over Monthly and Annual Excess Generation 6
b. Valuing Net Metering with Retail Rate Design 7
c. Using Time-of-Use Pricing to Incentivize PV Deployment 8
d. Reducing Demand Charges that Undermine PV System Economics 9
e. Weighing the Costs and Benefits of Net Metering 9
2. METER AGGREGATION 11
3. COMMUNITY SOLAR 11
a. Joint Billing 12
b. Virtual Net Metering 12
c. Joint Ownership 13
d. Utility Programs 13
e. The Value of Participation 14
f. Compensating Utilities 15
4. INCENTIVE PROGRAMS 15
a. Eligibility for State Incentives 16
b. Transfer of Renewable Energy Certificates or No Transfer 17
c. Up-Front Incentives versus Performance-Based Incentives 17
d. Predetermined Pricing or Market-Based Pricing 18
RETAIL MARKET POLICY CONCLUSIONS 18
WHOLESALE MARKET POLICIES 19
1. AVOIDED COST 20
a. Variations in State Avoided Cost Programs 21
b. Establishing Utility Avoided Cost Rates 22
c. Is PURPA Relevant Now That States Have Enacted RPS Standards? 23
d. Supplementing Avoided Cost with Payment for Renewable Attributes? 23
2. RENEWABLE ENERGY CREDIT MARKETS 24
3. FEED-IN TARIFFS 25
a. Existing State and Utility Feed-in Tariff Programs 26
b. Establishing Feed-in Tariff Rates 27
4. MARKET-BASED PROCUREMENT METHODS (RFPs/AUCTIONS) 28
a. Existing State and Utility Targeted RFP Programs 28
b. Establishing Market-Based Rates 29
WHOLESALE MARKET POLICY CONCLUSIONS 30
RECOMMENDATIONS 31
REFERENCES 35
ACRONYMS 37
ENDNOTES 38

INTRODUCTION

During the past 10 years, there has been a significant increase in photovoltaic (PV) system investment in the United States. Recent trends, including a steady reduction in the cost of PV system components, suggests that this growth is likely to continue for the next decade and beyond.

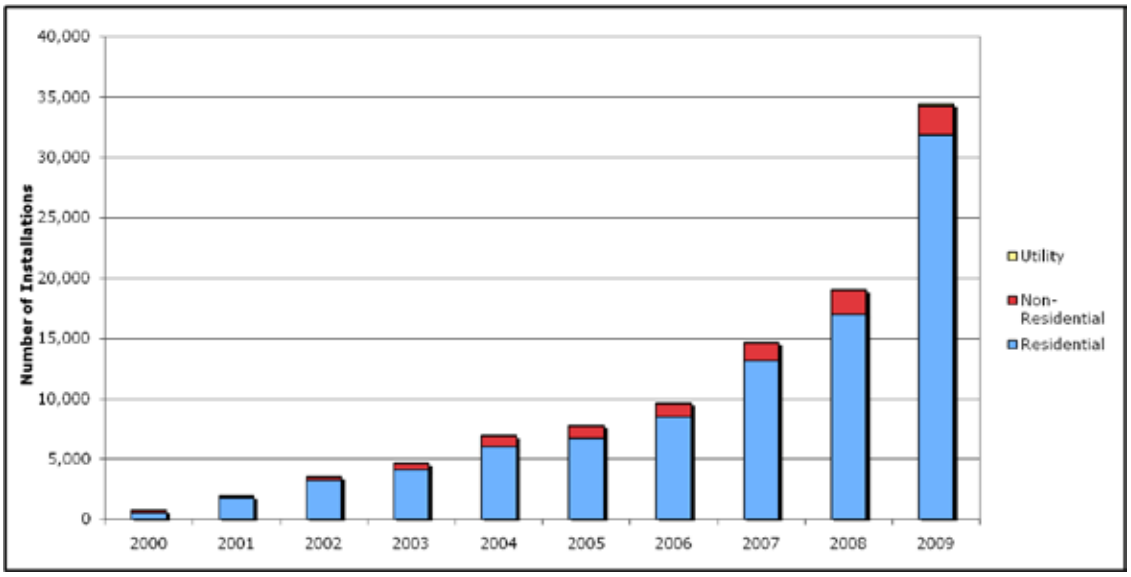

Figure 1: Number of Annual Grid-Connected Distributed and Utility-Scale PV Installations (1999-2009)[1]

A number of foundational policies have been implemented at federal, state, and local levels to facilitate the steady increase in PV system investment. At a federal level, tax incentives have proven instrumental to making PV systems cost-effective across a range of applications. At a state and local level, a range of important policies—including standardized interconnection procedures, streamlined permitting requirements, sales and property tax exemptions, net-metering policies, PV-friendly retail electric rate design, and incentive programs—has further stimulated investment in PV systems.

Among these policy tools, net metering has proven particularly important in facilitating U.S. PV system investment. In large part, the importance of net metering to U.S. PV system installations has been due to an absence of effective policies that otherwise might encourage development of a stronger wholesale PV market. There are many reasons why wholesale markets have failed to develop, but these are beyond the scope of this paper. What is important is that in the absence of effective wholesale policies, U.S. PV market growth has instead relied on retail policies, such as net metering, to facilitate customer investment in PV systems. In fact, in 2009, 85% of installed PV system capacity in the United States was customer-sited and most of those system owners enrolled in net metering programs.

Policies that support growth in U.S. PV markets are in many cases different than those that have been used to facilitate PV market development in other countries. While the United States has relied on retail market policies, such as net metering, some other countries have relied heavily on wholesale policies, such as feed-in tariffs (FITs), to facilitate investment in PV.

This paper originated as an effort to examine whether U.S. net-metering policy has been evolving in the direction of wholesale policies, such as FITs, that have facilitated PV market growth outside of the United

> "... in the absence of effective wholesale policies, U.S. PV market growth has instead relied on retail policies, such as net metering, to facilitate customer investment in PV systems."

States. What the authors found in conducting research for this paper is that U.S. net-metering policies are indeed evolving but not toward wholesale policies that have been deployed in other countries. Rather, net metering policies have expanded to become more available to a wider group of participants. Net-metering is currently available in 43 states, the District of Columbia, and Puerto Rico. During the past two years, more than half of these jurisdictions have revisited and expanded their net metering policies. As a result, 18 states plus D.C. and Puerto Rico now allow systems larger than one megawatt (MW) to be net metered and 19 states plus D.C. and Puerto Rico have removed their program enrollment caps.[2]

State and local policy makers have also expanded retail policies to allow generation from a single PV system to be used for self-supply purposes at multiple locations. This evolution appears to be driven by a recognition that many customers who are interested in investing in a PV system are not able to host an onsite system. For example, renters and occupants of multi-tenant residential and commercial buildings often lack the control of their premises necessary to host an onsite PV system. Shading and structural concerns may also prevent some customers from installing an onsite system. Furthermore, customers may have load from multiple properties they wish to offset with a single PV system.

There has also been significant interest in developing wholesale policy options to expand market opportunities beyond retail, self-generation markets. Interest in expanding wholesale market opportunities appears to be motivated by four key considerations: (a) a desire to support investment in larger PV systems beyond those that primarily serve onsite load; (b) a recognition that existing wholesale procurement mechanisms tend to favor very large generators to the near exclusion of distributed systems; (c) an appreciation that the unique benefits of distributed PV generation may justify payment of a higher wholesale price than is provided to larger grid-scale power projects; and (d) a realization that FIT programs have brought large amounts of distributed PV capacity online in European countries such as Germany and Spain.

Retail Market Policies

Consumers in retail PV markets are end-use electricity consumers who, for a variety of reasons, want to self-supply some or all of their electricity with PV generation. The pursuit of self-sufficiency means consumers in this market are interested in investing in a PV system that is sized to meet some portion of their personal electricity needs. For these consumers, PV system cost-effectiveness is measured against other options that are available for meeting personal electricity needs. Typically, such options are limited to retail rate options that are available through an electric utility.

Policies that have proven successful in motivating consumer investment in this market allow retail customers to generate and use PV power with minimal effort. These policies provide easy enrollment, minimal ongoing obligations, and no hidden fees. They also avoid the creation of taxable benefits and regulatory requirements that can often accompany participation in wholesale market programs. Successful retail policies are designed to ensure that all interested customers have an opportunity to invest in a solar system for self-generation purposes. This often includes customers with multiple meters and customers who cannot directly host a PV system.

"Policies that have proven successful in motivating consumer investment in this market allow retail customers to generate and use PV power with minimal effort."

To the extent an intermittent PV system generates more electricity than is needed at any given point in time, successful retail policies satisfy customer expectations that self-generation will result in reduced electricity purchases from the local electric utility. Customers who generate

their own power expect that a kilowatt-hour (kWh) of PV energy that is self-generated will result in an avoided kWh purchase from a utility. To address mismatches between intermittent PV generation and variable consumption needs, these successful retail policies provide a retail rate credit for excess electricity that is exported to the grid.

Successful policies also provide a value proposition that makes a PV investment cost-competitive with electricity supplied by retail electric service providers. Providing such a value proposition often requires a well-considered mix of retail rate design, targeted incentives, and policy options that provide consumers with the expected benefits of self-generation.

The policy options discussed in the Retail Market Policies section of this paper include net metering and meter aggregation policies; community solar policies such as joint billing, virtual net metering, and joint ownership; and PV incentive programs. Because these are retail policies, they can be designed and implemented by state and local policy makers whose jurisdiction includes oversight of retail electricity service.

Wholesale Market Policies

Typically, participants in wholesale PV markets are independent power project developers—not end-use electricity customers—who develop projects that are principally designed to sell power at wholesale prices to an electric utility. Wholesale market policies may be designed to allow a wholesale system to supply onsite electricity needs with excess electricity production sold at wholesale rates. However, many wholesale projects are located where there is little to no onsite electricity demand.

Although the benchmark for solar cost-effectiveness in retail PV markets occurs when the cost of solar generated power is at or below the retail rates offered by a retail electricity provider—a utility, for example—the benchmark for cost-effectiveness in wholesale PV markets is measured against wholesale power prices with similar hourly supply characteristics such as daytime generation that is located close to end-use retail electric load. This is the cost with which PV generation must compete in wholesale markets to be considered cost-effective. Retail electricity prices from a utility or retail electricity provider may be as much as two or three times the price of wholesale electricity prices.

Policies that have proven successful in supporting wholesale market development are designed to provide a level of compensation that ensures PV systems may be developed and operated profitably while also minimizing procurement costs to ratepayers. To achieve these twin goals, successful wholesale programs employ a streamlined procurement process that lowers transaction costs to developers while also ensuring that only the most viable and cost-effective projects are awarded contracts to supply utility ratepayers.

The policies discussed in the Wholesale Market Policies section of this paper include avoided cost pricing mechanisms, renewable energy credit (REC) markets, FITs, and market-based procurement mechanisms such as auctions and requests for proposals (RFPs). State and local policy makers may be limited in their ability to deploy FITs that feature prices that exceed utility avoided costs because the Federal Energy Regulatory Commission (FERC) exercises exclusive jurisdiction over wholesale electricity markets. FERC jurisdiction limits the ability of state policy makers to establish wholesale power prices.

"FERC jurisdiction limits the ability of state policy makers to establish wholesale power prices."

Recommendations

In the final Recommendations section of this paper, we examine the billing and payment options that have been adopted in the 10 states that have the largest base of installed PV capacity. A number of these states have taken a multi-segment approach to developing

sustainable markets for distributed PV development. This demonstrates that retail and wholesale market policies do not represent alternatives so much as complementary means for promoting growth in different PV market segments. Drawing upon lessons learned from the leading state markets for PV deployment, the final section of this paper recommends a sustainable, multi-segment distributed PV market design.

RETAIL MARKET POLICIES

During the past decade, advances in PV technology and implementation of supportive government and utility policies have allowed PV to reach a price point in many areas of the country where customers can cost-effectively generate electricity to serve much of their own personal energy needs. The pace of PV market growth during the last 10 years demonstrates that many retail electricity consumers in the United States have embraced this option. Their reasons for investing in PV are varied and the benefits of their investment in clean, renewable energy capacity are only beginning to be fully appreciated.

In this section, we focus on retail market policies for PV to help policy makers and interested stakeholders better understand how well designed retail market policies for PV can further encourage customer investment in these technologies. Figure 1 shows that a large percentage of PV systems are installed at residential locations, which are well suited for retail market policies.

This section begins with a discussion of net metering, the most widely adopted retail policy for facilitating growth in retail PV markets. In the subsections that follow, we discuss the importance of utility retail rate levels and residential and commercial retail rate design in making PV cost-effective from a customer's perspective. We also address the importance of considering a full range of PV system benefits in determining the cost effectiveness of net metering and retail rate design. Too often these important considerations are ignored in looking at the cost-effectiveness of policies that support retail PV deployment.

Next, we discuss meter aggregation and community solar options, such as joint billing and virtual net metering, that many states have recently implemented to expand retail markets for PV. Many retail customers interested in supporting or investing in a PV system to green their power supply and pursue self-sufficiency are not able to install an onsite system because they do not own residential or commercial property or don't control their residential or commercial building. Other challenges include shading issues or inadequate roof structural support. The policies discussed in this section of the paper address this problem by providing the benefits of onsite solar generation to participants that invest in or support an offsite system.

This section concludes with a discussion of incentive programs that are often used in concert with the above policies to make investment in PV cost-effective from a customer's perspective.

1. NET METERING

Net metering is very well suited to promoting onsite generation because it allows utility customers to host an onsite system and receive a simple, direct, and timely financial benefit in the form of a reduced utility bill. To many customers, this is preferable to the taxable income and regulatory compliance requirements that arise from selling power to a utility under the wholesale programs that are discussed in the Wholesale Market Policies section of this paper.

Net metering is available in some form in 43 states and the District of Columbia.[3] Net metering allows customers with PV systems and other types of distributed generation systems to send excess power to the utility grid and receive a 1:1 kWh credit for use at a time when a system is not producing as much electricity as a customer needs. By providing a 1:1 kWh credit for electricity that is not immediately needed, net metering allows customers to receive the same financial value for all energy produced onsite—a value equivalent to a customer's savings from avoided electric utility power purchases.

a. Carrying Over Monthly and Annual Excess Generation

Most state net metering policies are uniform with respect to netting utility-supplied electricity against customer-exported electricity on a 1:1 kWh basis across a billing period to determine a net-metered customer's monthly retail electric bill. If a customer consumes more electricity onsite than he or she generates, that customer pays a utility for supplying the extra kWh needed to supplement onsite generation. On the other hand, if a customer generates more electricity than is needed onsite, that customer is a net excess generator for the billing period.

A key consideration in establishing successful net metering programs is what to do if a customer generates more electricity during a billing period than that customer consumes. State policies differ with respect to how they treat monthly net excess generation (NEG). Most states roll over monthly NEG onto a customer's next utility bill as either a kWh or dollar credit. Thirty-eight states currently use a full retail credit rollover approach. Only Alaska, Minnesota, and North Dakota do not rollover monthly NEG as a credit onto the customer's next bill and instead require a monthly payment for NEG. Oklahoma and New Mexico allow utilities discretion to either credit the next bill or provide a payment.[4]

From a customer's perspective, a simple rollover of NEG onto a customer's next month's bill has significant value. This allows customers the flexibility to size a system to meet onsite needs even if those needs vary from month to month. This can be particularly helpful for customers with electricity needs that vary significantly by month or season. Schools and agricultural customers are good examples. Schools have reduced electricity needs when school is not in session. Likewise, agricultural customers often require greater electricity use during certain seasons. Without monthly rollover at retail value, customers such as these may have insufficient financial incentive to size a system to meet full onsite energy needs and may instead only install a system that meets energy needs during the lowest month of electricity usage during the year. This may significantly impede the growth of retail PV markets.

For the majority of states that allow monthly rollover of NEG at retail rate value, a question arises as to whether monthly excess generation may continue to rollover in perpetuity or whether credits may be treated differently at the end of an annual period. State policies generally fall into four categories with regard to treatment of annual NEG.

First, 14 states plus the District of Columbia allow indefinite rollover of credits with no annual true up. These include Colorado (customer may opt for indefinite rollover), Delaware (customer may opt for indefinite rollover), District of Columbia, Indiana, Iowa, Kentucky, Louisiana, Massachusetts, Michigan, Minnesota (reconciled monthly at average retail energy rate with no annual true up), Nevada, New Hampshire, New Jersey (optional for customer), New York (for non-residential customers with wind and solar), and Wisconsin (reconciled monthly at retail rate for renewable generators with no annual true up).[5]

"A key consideration in establishing successful net metering programs is what to do if a customer generates more electricity during a billing period than that customer consumes. State policies differ with respect to how they treat monthly net excess generation (NEG). Most states roll over monthly NEG onto a customer's next utility bill as either a kWh or dollar credit."

Second, 15 states provide payment for annual NEG at a utility avoided cost rate (see Avoided Cost section of this paper for more information on avoided cost rates). These states are Alaska (reconciled monthly at avoided cost), Arizona, Colorado (optional for customer), Connecticut (avoided cost for non-PV customers and time-of-use [TOU] generation rate for PV customers), Delaware (optional for customer), Florida, Nebraska (reconciled monthly at avoided cost), New Jersey, New Mexico (reconciled monthly at avoided cost), New York (residential

customers), North Dakota (reconciled monthly at avoided cost), Ohio (reconciled monthly at "unbundled generation rate" or energy-only component of the retail rate), Virginia, Wisconsin (reconciled monthly at avoided cost for non-renewable generators), and Wyoming.[6]

Third, Pennsylvania and Puerto Rico provide payment at some other amount. In Pennsylvania, PV customer accounts are reconciled annually at the "price to compare," which includes generation and transmission components of the retail rate, and in Puerto Rico, the utility purchases 75% of outstanding NEG credits at a minimum rate of $0.10/kWh, and the remaining 25% of credits are donated to public schools.[7]

Fourth, 17 states and the Virgin Islands grant annual NEG to a utility with no compensation provided to a customer-generator. These include Arkansas, Hawaii, Georgia, Illinois, Kansas, Maine, Maryland, Missouri, Montana, North Carolina, Oregon (donated to low income program), Rhode Island, South Carolina, Utah, Vermont, Virgin Islands, Washington, and West Virginia.[8]

From a net-metered customer's perspective, the decision to provide rollover of monthly NEG on a 1:1 kWh basis is likely to be of greater financial importance than the treatment of annual NEG. Monthly rollover smoothes out mismatches between monthly onsite generation and energy needs, which are common to many customers. Annual rollover, by comparison, helps smooth out variations in onsite electricity needs that may occur from one year to the next. This can be important for customers like commercial building owners that may have annual variation in onsite electricity needs due to building occupancy changes. However, most net-metering policies restrict the size of a net-metered system to what is necessary to supply onsite electricity needs on an annual basis. As a consequence, most net-metered systems do not generally generate more energy than is needed on an annual basis. This means that state net-metering policy treatment of annual NEG does not impact the majority of net-metered customers. That said, 14 states plus the District of Columbia have chosen to maximize customer flexibility in sizing a system to meet onsite needs by allowing indefinite rollover of credits with no annual true up.

b. Valuing Net Metering with Retail Rate Design

From a participating customer's perspective, the value of onsite generation and net metering is dependent on the electric retail rates a customer would otherwise pay in the absence of self-generation. Higher retail rates provide more motivation to install onsite generation in order to avoid paying those rates.

At the time of this writing (July 2010), state average retail electricity prices in the United States ranged from $0.061 in Wyoming to $0.237 per kWh in Hawaii, with an overall average retail price of electricity to the consumer across all end-use sectors (residential, commercial, industrial, and transportation) of $0.094 per kWh.[9] The variation in state retail rates provides for widely different outcomes in the financial payback of PV projects and helps explain why states with relatively low electricity prices have generally lagged behind in terms of installed PV capacity.

Table 1 (on the following page) provides information on the average retail rates in the top 10 states with the most installed PV capacity.

Table 1: Average retail electricity rates for top solar states[10]

State	2009 Cumulative Installed MW Capacity	Average Retail Rate, June 2010, cents/kWh
1. California	768	13.22
2. New Jersey	128	14.37
3. Colorado	59	9.14
4. Arizona	46	9.36
5. Florida	39	10.31
6. Nevada	36	9.58
7. New York	34	16.02
8. Hawaii	26	24.71
9. Connecticut	20	17.54
10. Massachusetts	18	14.52

Many states that have a gap between cost of generation from a PV system and prevailing retail rates have sought to close that gap by adopting PV incentive programs. This helps explain why states such as Colorado and Arizona have robust retail markets for PV systems despite having retail electric rate levels that are below the U.S. average. For an extensive discussion of state incentives that aim to close the gap between PV cost and PV value please see the section on Incentives.

A recent study by the National Renewable Energy Laboratory (NREL)(Denholm, Margolis, Ong, and Roberts, 2009) highlights the importance of state retail electricity price differences on the attractiveness of residential customer investment in PV systems. This report concluded that the difference in the break-even cost of PV is "largely driven by incentives, which can exceed $5/W, and the difference in electricity prices, which can vary by a factor of eight (or more when considering the range of tiered rates in California)."

c. Using Time-of-Use Pricing to Incentivize PV Deployment

Although state average retail electricity rates offer a rough rule of thumb for states in which retail PV systems are likely to be more cost-effective, the design of retail rates is also important in determining customer motivation to invest in PV systems. Well-designed TOU pricing, in particular, can allow customers with PV systems to offset high on-peak retail prices and may play an important role in making net-metered PV systems financially attractive to participating customers.

Although TOU structures with high on-peak to off-peak pricing differentials are likely to be financially attractive to many customers, load profiles of PV customers can vary widely, as can the size of onsite systems. As a result, a PV installation may offset anywhere from a few percent to more than 100% of a customer's onsite energy needs. At lower percentages, standard tariff options may be more favorable to customers than TOU rate structures. In fact, the NREL break-even report (Denholm et al., 2009) found that:

> "TOU rates do not always result in a net benefit to a customer even when PV has higher value on TOU rates. We found that about 20% of TOU rates evaluated showed decrease in PV values when shifting the customer from a flat rate to a TOU rate."

Therefore, although TOU rates can be an important tool in incentivizing PV system deployment, retail tariff choice is also important, particularly for customers with PV systems that are sized to serve a small percentage of onsite electricity needs.

d. Reducing Demand Charges that Undermine PV System Economics

At a more granular level, the components or structure of retail rates may be as important as average rates—or even on-peak TOU rate levels—in understanding customer motivation to invest in a PV system. Demand charges are a particularly important consideration in rate design for net-metered customers. Demand-based charges are based on the maximum kilowatt (kW) demand served by a utility, typically measured by a customer's highest usage during a 15-minute period within a monthly billing period or annual billing cycle.

Due to the intermittent nature of PV production, customers with PV systems have a difficult time lowering demand charges. As a consequence, rate structures that place a significant percentage of electricity service charges into a demand-based billing component measured in kW, instead of volumetric energy charges measured in kWh, can undermine the economics of investing in a PV system. Although demand charges are less common in residential retail rates, they are ubiquitous in commercial and industrial rates.

A Lawrence Berkeley National Laboratory (LBNL) report (Wiser, Mills, Barbose, and Golove, 2007) confirms that demand charges can represent a significant barrier to the penetration of commercial PV systems. This report studied a broad range of retail rate options available to commercial PV customers in California and concluded that solar output often will not result in significant reductions in a customer's demand charges, particularly for PV systems that are sized to meet a large percentage of a customer's onsite energy needs. For these customers, demand charges can significantly undermine the financial case for investing in PV, or—at a minimum—can compel customers to invest in smaller PV systems that only meet a small percentage of onsite electric energy needs.

Demand charges also make it difficult for a PV customer to monitor, anticipate, and control demand for grid power. This creates a disincentive for a net-metered customer to lower demand and increase generation to the maximum extent possible during all on-peak periods. A TOU tariff with low or no demand charges, on the other hand, provides a strong incentive for a customer to reduce demand and increase generation (if possible) during on-peak periods. In aggregate, such actions increase customer incentives to invest in larger PV systems that, in turn, may reduce the need for new distribution, transmission, and generation capacity, as well as scale down a utility's long-run marginal cost of providing service.

"... rate structures that place a significant percentage of electricity service charges into a demand-based billing component measured in kW, instead of volumetric energy charges measured in kWh, can undermine the economics of investing in a PV system."

e. Weighing the Costs and Benefits of Net Metering

It is clear that more work is needed to demystify the unique costs and benefits of customer investment in PV systems. An NREL report (Johnston, Takahashi, Weston, and Murray, 2005) found that "[a]lthough the benefits of [distributed generation] have been generally acknowledged by policy makers, methods of accounting for those benefits, in ratemaking as well as planning, are not yet well developed." Without a full and fair accounting of these benefits, it is exceedingly difficult to determine whether customer investment in PV systems creates a net benefit or net cost from the utility perspective.

A number of important considerations must be taken into account to accurately measure the societal and utility-side benefits and costs of customer-owned net-metered PV. More than a simple "back of the envelope" comparison of high-tiered retail electricity rates and utility avoided cost rates is needed (see the Avoided Cost section for more information).

First, it is important to consider that a customer who invests in and maintains net-metered PV may have a lower cost of service than a customer without onsite PV. This is be-

cause PV is a reliable source of daytime generation. Although the generation of any particular solar system may vary with local weather conditions, PV production is available at times of the day when electricity demand and the cost of meeting that demand is highest. This means that customers who install PV may have a lower average cost of service because they are meeting some or all of their own needs at times of the day when utility provision of service would be most costly.

Second, it is important to consider the precise cost of providing a net-metering credit. It is fair to question the extent to which the highest retail rate that may be in effect at the time of *any* net-metered export accurately reflects the cost to a utility of providing net metering credits. Only a portion of net-metered energy exports occurs during on-peak periods. In fact, many TOU tariff structures lack on-peak rates for entire months or seasons of the year, and many TOU tariffs exclude from on-peak periods morning or afternoon hours during which net-metered PV systems may be exporting. As a corollary, customers on inclining block rate structures, which charge consumers who use a lot of energy more for their higher energy usage, may not use enough power to reach higher-tiered rates. Therefore these customers do not receive a credit that is used to offset power use in the highest block. In addition, some net-metering programs apply on-peak TOU credits against off-peak usage. In such cases, lower priced off-peak prices are a better reflection of both the value to a participating customer and the cost to a participating utility.

Third, customer investment in distributed PV may help utilities reduce long run marginal costs, which decrease the costs that must ultimately be recovered in retail rates that all customers pay. These avoided costs include: (a) increased electricity supplies, placing downward pressure on electricity market prices; (b) reduced need for electricity from natural gas fired power plants, placing downward pressure on natural gas market prices; (c) reduced loading on transformers and substations, delaying the need for replacements or upgrades; (d) deferred or avoided distribution line and substation upgrades; (e) fuel diversity benefits; (f) enhanced grid reliability; and (g) environmental benefits such as reduced greenhouse gas emissions and emissions of criteria pollutants (Iannucci, Cibulka, Eyer, and Pupp, 2003).

In light of the above considerations, a simple TOU rate with low demand charges and a high on-peak to off-peak price differential may be justified. It may also align financial incentives of participating customers with benefits to non-participating customers by creating an incentive to install PV systems for which peak production coincides with utility peak electricity demand.

Recognizing these benefits, the California Legislature adopted California's $3 billion CSI PV incentive program, which directed the state's public utility commission (PUC) to adopt rates for participating customers that:

> "create the maximum incentive for ratepayers to install solar energy systems so that the system's peak electricity production coincides with California's peak electricity demands and that assures that ratepayers receive due value for their contribution to the purchase of solar energy systems and customers with solar energy systems continue to have an incentive to use electricity efficiently."

Public Utilities Code Sec. 2851(a)(4)(a), from which this quote is taken, originally required the California Public Utility Commission (CPUC) to create such rates. In 2008, however, the California Legislature amended this section to make the creation of such rates optional and to eliminate the requirement that all CSI participants take service under time–of-use rates.

A companion paper to this one, titled *Rate Impacts of Net Metering*, soon to be published by the Solar ABCs, provides a further elaboration of how PV benefits may be appropriately considered in designing rates for customers with net-metered PV generation.

2. METER AGGREGATION

Meter aggregation is an expansion of net metering that facilitates customer investment in PV systems that are not located at the site where the customer wants to use the electricity. Meter aggregation programs allow a customer to generate bill credits from a PV system and apply those bill credits to multiple electric utility billing accounts that are under a single customer's name.

State and utility meter aggregation policies differ in how geographically dispersed meters may be from a site where a PV system is located. Some meter aggregation policies require that dispersed meters (and hence billing accounts) be located on the same property or property that is adjacent to where a net-metered facility is located. For example, Oregon's net-metering policy allows a single customer's meters to be aggregated as long as they are on contiguous properties owned by that customer.[11] Pennsylvania and West Virginia allow meters to be located within two miles of a net-metered generator.[12] Agricultural customers, universities, municipalities, and other large customers with dispersed operations are often primary beneficiaries of meter aggregation policies.

Meter aggregation is currently allowed for at least some customer classes in California, Delaware, Pennsylvania, Washington, Oregon, Vermont, Rhode Island, West Virginia, and New Jersey.[13] At the time of this writing, meter aggregation programs were also under consideration in Maryland, Connecticut, and Arizona.

3. COMMUNITY SOLAR

Community solar expands on meter aggregation by allowing multiple customers to come together and support a single PV system. Many definitions have been applied to community solar. This paper adopts a definition used by the Bonneville Environmental Foundation in its *Northwest Community Solar Guide* (Bonneville Environmental Foundation):

> "a solar-electric system that, through a voluntary program, provides power and/or financial benefit to, or is owned by, multiple community members."

A number of states and utilities have recently implemented community solar programs as a means of facilitating customer investment in renewable energy. Interest in these programs appears to come from recognition that while current policies that promote onsite generation have benefited many homeowners and businesses, many utility customers are not able to host an onsite system. For example, renters and many occupants of multi-tenant residential and commercial buildings may lack necessary control of their premises to host an onsite PV system. Add to that shading and onsite structural concerns, and it becomes clear that many would-be solar supporters may not be able to install an onsite system. In fact, a 2008 NREL study (Denholm and Margolis, 2008) found that only 22% to 27% of residential buildings are suitable for hosting an onsite PV system. Thus, the market for PV that could be supported by well-designed community solar policies is considerable.

There have been a number of approaches taken by state policy makers to establish community solar programs that bring solar options to a broader group of participants. The following sub-sections group these approaches into four broad categories:

- joint billing policies
- virtual net metering
- joint ownership
- utility programs

We introduce each of these approaches below and discuss the financial advantages of each approach from a participant's perspective. This section concludes with a discussion of approaches states have taken in compensating utilities for administering community solar programs.

a. Joint Billing

Joint billing acts much like master-metering in a multi-tenant building, a situation in which landlord receives a single bill for all tenant electricity usage, and then determines how to parcel out costs to individual tenants. Joint billing for community projects works the same way in that the electricity use of participants is aggregated into a joint bill. However, participants do not need to reside in a single building and may instead be more dispersed.

Output from a shared PV system is netted against a joint bill. This allows multiple participants to receive financial benefits equivalent to net metering from a single PV facility. Vermont, for example, has enacted a joint billing program for shared systems in which a group of customers may combine meters and form a single billing entity to offset their joint bill with generation from a net-metered system.[14]

A downside of this approach is that a customer representative must serve as a point of contact and intermediary between a group of participants and a utility by taking on such tasks as billing and dispute resolution.

b. Virtual Net Metering

Similar to meter aggregation and joint billing, virtual net metering (VNM) allows a renewable energy system to offset load at multiple electric accounts. Massachusetts, Rhode Island, California and Maine have all implemented virtual net metering programs.

Massachusetts has implemented the most expansive virtual net metering policy to date.[15] Massachusetts' "neighborhood net metering" program allows neighborhood-based facilities to serve the energy needs of a group of at least 10 residential customers in a neighborhood. Under Massachusetts statute, a neighborhood is defined as a geographic area including and limited to a unique community of interests that is recognized as such by residents and which, in addition to residential and undeveloped properties, may encompass commercial properties. A neighborhood must also remain within a utility's electric service territory.

A neighborhood system must be behind a participating customer's meter, but only a minimal amount of load needs to be located onsite. Participating utilities allocate kWh credits to participating customer accounts based on allocations provided by a customer representative. To account for distribution of electricity to participants, utilities are not required to issue the distribution component of a bundled retail rate, which includes all other service and administrative charges, in neighborhood net metering credits that are applied to participants' bills. This results in a credit that is substantially (as much as 40%) below the credit typically provided through net metering.

Massachusetts also allows customers with traditional net-metered systems to allocate excess monthly generation to one or more other customers of the same distribution company. Under this method, distribution utilities apply the allocated credits to the bills of designated customers. Credits for these non-neighborhood systems reflect a fully bundled retail rate credit and are allocated as a dollar-denominated credit based on the retail rate of the customer account where a net-metered system is located (i.e. using the retail rate of the host customer in $/kWh multiplied by the kWh allocation).

Rhode Island has also implemented an extensive virtual net-metering policy.[16] It allows cities, towns, schools, farms, non-profit affordable housing, and state agencies to participate. Under Rhode Island's program, customers may either install a renewable

energy system and receive a monthly check (at a rate slightly less than retail) or apply excess kWh credits to up to 10 other accounts they own. If a non-profit affordable housing agency chooses compensation, it is obligated to use the money to benefit residents.[17]

California and Maine have also implemented virtual net metering programs. California allows multi-family, low-income residents to receive bill credits from a single onsite PV system.[18] Maine's program is open to a broader group of participants. It works like the virtual net metering programs discussed above except that Maine requires participants to have an ownership stake in a shared net-metered system.[19] Generation is then virtually net metered to joint owners in proportion to their ownership stake in a system. For example, a 50 % owner would receive 50 % of the virtually net-metered bill credits generated by a system.[20] This makes Maine's program a hybrid approach that couples virtual net metering with joint ownership, which is discussed in the next subsection.

c. Joint Ownership

Taking a page from successful community wind programs, some states have begun to explore community ownership programs for PV systems. For example, Maine has both a retail and wholesale program for community solar. Both require joint ownership. Maine's joint ownership net-metering program was discussed in the prior subsection. Maine's wholesale program is called a Community-Based Renewable Energy Pilot Program.[21] It allows "locally owned electricity generating facilities" with at least 51 % ownership by "qualifying local owners" to elect one of two incentive mechanisms: (a) a long-term contract to sell the output of a facility to a transmission and distribution utility; or (b) a REC multiplier in which the value of RECs generated by a locally owned system are valued at 150 % of the amount of electricity produced. The contract price for solar energy may vary over the course of a year, but the average price, weighted on the expected output of a facility, may not exceed $0.10/kWh. Although this is a relatively low price compared to some state FIT prices, this price is for electricity only and does not include an additional REC purchase.

The State of Washington is also establishing a community solar program that relies on community ownership to impart a community flavor. Whereas most community solar programs allow participants to receive bill credits as a benefit of participation, community participants in Washington will install a PV system on property owned by a cooperating local government entity and will sell electricity from that system to the government entity. Participants, who are owners of the system, receive incentive payments through Washington's state incentive program (see the following Incentive section for more on the incentive program) and also receive income from the sale of power to the onsite local government entity. Participants may also receive revenue from the sale of RECs.

d. Utility Programs

A number of utilities have independently implemented community solar options as a way to satisfy customer interest in PV systems and diversify their generation base. From a utility's perspective, community solar programs can allow for voluntary customer participation as opposed to passing through PV system costs to all ratepayers. From a customer's perspective, contributing to a single, larger PV system that is installed by a utility can significantly decrease the obstacles of purchasing, interconnecting, and maintaining an individual system on his or her property.

The City of Ellensburg, Washington, was the first utility in the country to set up a virtual net metering, community ownership PV system.[22] Ellensburg's municipal utility enrolled over 70 community investors who contributed a minimum of $250 each, but some contributed over $11,000. A contribution allows each investor to receive a bill credit on his or her electric bill proportionate to the investment for 20 years. (Nystedt, 2008).

For example, if a customer's contribution represents 3% of the total funds contributed by utility customers, that customer would receive 3% of the power produced by the PV project, applied as a credit to offset his or her electric bill (Nystedt, 2008).

The City of Seattle is developing a local community solar program that will be managed by its municipal utility, Seattle City Light. Under this community solar program, Seattle City Light will finance up-front investment in a PV system, but will be reimbursed by customer participants who will contribute financial support in exchange for a payment or a credit on a utility bill. The amount of the payment or credit will be based on the value of electricity produced by a system. This follows a virtual net metering approach similar to one that has been implemented by the Sacramento Municipal Utility District, which is called "Solar Shares."

The City of St. George, Utah offers a similar community program called "SunSmart." Through this program, utility customers purchase PV units ranging from $3,000 to $24,000, and in return receive a bill credit "pro-rata share of the net electrical output of the SunSmart project" for the commercial life of the system (projected for 19 years).[23] Because customers are purchasing panels, customers are eligible to take the state's 25% tax credit, up to $2,000, on their purchase.

While most utility programs have been initiated by municipal utilities, in early 2010, the Florida Keys Electric Cooperative (FKEC) was the first non-municipal utility to offer a community solar program. Through FKEC's "Simple Solar Program," co-op members can lease one or more solar panels in a utility-owned array for $999 each. In return, members receive monthly bill credits for the full retail value of the electricity generated by leased panel(s) for 25 years.[24] FKEC estimates that each $999 investment will return about $1,280 in credits over the life of the lease, assuming a 3% annual increase in electricity prices.

e. The Value of Participation

The above examples illustrate that a number of approaches have been explored in facilitating community solar projects. The compensation level provided through these efforts largely depends on whether a program allows a participating customer to use generation to offset retail electricity consumption (joint billing or virtual net metering programs) or to sell power at wholesale to a participating utility (Maine's Community-Based Renewable Energy Pilot Program) or at retail to an onsite customer (Washington's community solar program). The compensation level also depends on whether community projects are able to receive available incentives, which is discussed in the next section.

Programs that allow participating customers to offset retail electricity purchases offer a value proposition similar to net metering. In other words, the value from a participating customer's perspective is highly correlated with retail rates a customer is able to avoid paying. Higher retail rates, and more advantageous retail rate structures, provide additional incentive for retail customers to participate in a community solar system.

Programs that are structured as a wholesale program, like Maine's Community-Based Pilot Program, compensate community solar participants by setting a level of wholesale payment. Maine's program limits this value to an average price, weighted on the expected output of a facility, which may not exceed $0.10/kWh. A significant downside of this approach is that, like the wholesale options discussed later in this report, and unlike the self-generation programs discussed above (net metering, meter aggregation, joint billing, and virtual net metering), payment from power sales to a wholesale or retail purchaser results in taxable income at a federal level and possibly also at a state level. The taxable status of these sales may significantly decrease the size of benefits available to participating customers and may act as a deterrent to an average utility customer who does not want to complicate his or her tax filings.

f. Compensating Utilities

With regard to meter aggregation, joint-billing and virtual net-metering programs, a question arises as to whether a utility should be compensated for providing the distribution and billing services necessary to facilitate self-generation programs. Different states have taken different approaches.

In Massachusetts, bill credits created by a "neighborhood net-metered facility" do not contain the distribution portion of a fully bundled retail rate. As a result, participants in a "neighborhood" facility pay distribution charges for the use of a utility's distribution system. Participants do not, however, pay transmission fees. This seems reasonable given that neighborhood systems are limited to 2 MW and participating customers must be located within a distribution utility's service territory. As a result, these systems will likely be located on distribution circuits near the load, and therefore will not require transmission infrastructure to distribute power to program participants.

California's virtual net metering takes a different approach. California conveys a fully bundled rate credit, including the distribution charge component, in virtual net-metering credits. However, unlike the Massachusetts' program, California's virtual net-metering program is available only to occupants of multi-tenant buildings. In other words, participating customers are likely to be centrally located on a single distribution circuit. Massachusetts' neighborhood net-metering program, by comparison, allows bill credits to be distributed more widely to participants who may not be within the same geographic proximity. Given these differences in potential geographic dispersal of program participants, it seems reasonable that California's program, which allows for significantly less geographic dispersal, would provide the financial benefit of a fully bundled retail credit while Massachusetts' programs subtracts a distribution fee from the value of bill credits.

4. INCENTIVE PROGRAMS

Financial incentives for distributed PV come in a wide variety of forms, including tax credits, rebates, grants, and performance-based incentives. This paper is predominantly concerned with state incentives that provide either an up-front rebate based on the size of a system or an on-going payment based on system output. State incentives of this sort can reduce the cost of a PV system by up to 50%—although most state rebate program caps are in the 25% to 35% range—and are important components of retail market design for PV. Tax credits and other forms of incentives are also valuable parts of the financial equation, but they are outside the scope of this report.

The goal of a well-designed PV incentive program is to provide sufficient compensation to a customer to make a PV system investment cost-effective, given available retail rate levels and structures and the availability of net-metering programs. As a corollary, retail electric rate design that reflects the costs and benefits of serving customers with PV systems can be coupled with effective net metering to reduce the level of incentives needed to make a PV system investment cost-effective. Thus, net metering, retail rate design, and incentives are all essential components of comprehensive retail market design for PV systems.

In this section, we discuss some of the key variations in state incentives programs, including:

- which system types are eligible for state incentives;
- whether participation in a state incentive program necessitates a transfer of the renewable attributes of power (via RECs) to a utility providing incentives;
- whether incentives are paid as a lump sum or up-front payment or are based on the performance of a system over a period of time; and
- whether incentive amounts are determined administratively or by a market mechanism.

a. Eligibility for State Incentives

State PV incentives are often only available to customer-generators who use distributed generation to serve onsite load. CSI is perhaps the most well-known example of such an incentive program. The CSI was launched in 2006 with an aim of providing more than $3 billion in incentives to spur 3,000 MW of solar installations by 2016 (2,550 MW of which are PV systems).[25] To be eligible for CSI incentives, a system must be "sized so that the amount of electricity produced by the system primarily offsets part or all of the Host Customer's electrical needs at the Project Site."[26]

North Carolina's NC GreenPower incentive program represents the other end of the spectrum, in that only customer-generators taking service under specific avoided cost tariffs (see Avoided Cost section of this report) are eligible for state incentives. NC GreenPower is not a state-sponsored program. It is administered by a non-profit organization supported by voluntary contributions from customers.

Coupling incentive payments—particularly production-based incentives—with a wholesale payment for power duplicates the financial incentives provided under a FIT (see Feed-in Tariff section of this report for a further discussion). Net-metered customers in North Carolina may not receive NC GreenPower incentives.[27]

Arizona's state-mandated PV incentive program represents a sort of hybrid of the CSI and NC GreenPower approaches. In Arizona, state-mandated incentives are only available to systems located on a customer's premises. However, unlike California's CSI program, there is no requirement in Arizona that a system must serve onsite load.[28] Like NC GreenPower, customer-sited systems may instead provide wholesale power to a utility.

It is also important to consider whether incentives are available to community PV systems. Washington's incentive program is available to onsite net-metered systems as well as community PV systems. Under Washington's program, utilities provide incentives to eligible generators and in return utilities receive a tax credit equal to the cost of providing incentive payments. Incentive amounts start at a base rate of $0.15/kWh and are adjusted by multipliers (for using locally produced system components) that result in an incentive range of $0.12 to $0.54 per kWh. Community PV projects are eligible to receive incentives that begin at a base rate of $0.30/kWh. With multipliers, incentives for community PV can reach $1.08/kWh.[29]

Community systems may have a difficult time achieving cost-effectiveness without access to state incentive programs. State incentives generally reduce the cost of a PV system by roughly 30%. A community system may enjoy certain economies of scale compared to a smaller onsite system, but it is unlikely those economies of scale alone can close a gap of 30% of system cost left by lack of availability of incentives. It is therefore essential that policy makers contemplating community solar policies consider extending state incentive payments to community systems. Without incentive eligibility, community solar programs may not be able to expand to their full market potential.

There is also a fairness consideration to extending incentives to community systems. Typically, all ratepayers (or taxpayers depending on the incentive program structure) contribute to funding PV incentive programs, yet not all ratepayers are able to host a PV system, and, as previously noted (Denholm and Margolis, 2008), only 22% to 27% of residential buildings are suitable for hosting an onsite PV system. For the majority of customers that cannot host a PV system, community solar programs may be the only means of participating in a PV system. Incentives for these systems provide a mechanism for all customers to participate in incentive programs they help fund.

b. Transfer of Renewable Energy Certificates or No Transfer

State incentive programs are often connected with renewable portfolio standard (RPS) policies that require utilities to incorporate PV or distributed generation into their resource mix. Seventeen states have created solar targets within their RPS programs.[30] Nine states have created distributed generation procurement targets or allow utilities a RPS credit multiplier for customer-sited systems.[31] Utilities subject to RPS requirements often offer incentives to renewable energy generators and incentive recipients convey renewable attributes of their generation (through RECs) to the utility for the utility's use in demonstrating compliance with its RPS obligations. This approach provides a financial incentive to customers to invest in renewable generation capacity and assists utilities in meeting their RPS policy goals.

Although many states have structured their incentive programs as a means of achieving RPS goals, other states have structured their incentive programs to achieve state objectives other than RPS goals. For example, California's CSI program is designed to achieve 3,000 MW of solar installations by 2016. This goal is separate from and in addition to California's RPS goal of procuring 20% of its wholesale electricity from eligible renewable sources by 2020. (California's governor has issued an executive order extending state renewable procurement requirements to 33% by 2020, but this gubernatorial policy has yet to be codified in state law.) Recipients of CSI incentives are not required to convey RECs to a utility in exchange for incentive payments.

Washington's production incentive program (discussed above) is similarly not tied to REC purchases and instead is designed, in part, to create a market for locally produced PV system components. Vermont, Wisconsin, Pennsylvania, and New Jersey also do not require a REC transfer in exchange for incentives.[32] In these states, policy makers have determined that incentives should be provided to support state goals other than achieving state RPS requirements.

c. Up-Front Incentives versus Performance-Based Incentives

Incentive payments can be structured as either up-front incentives (UFIs) or performance-based incentives (PBIs). UFIs are paid in a lump-sum amount, typically at the time a system is installed or begins operation. PBIs are paid over time and are based on metered output of a system. Often, state incentive programs provide UFIs to smaller systems and PBIs to larger, commercially owned systems.

For example, Maryland utilities purchase RECs from PV systems of 10 kW or less through a single up-front payment. The California CSI program provides UFIs to systems up to 30 kW and PBIs to those larger than 30 kW. PBI payments are paid monthly over a five-year period.[33]

From a public policy perspective, PBI payments provide a significant incentive for customer-generators to maintain a system and maximize output. This protects ratepayers who fund PV incentive programs from overpaying for poorly performing systems. PBI payments also make sense from a financing perspective. The stable and predictable income stream provided by a PBI payment is often sufficient to facilitate financing of larger commercial systems. Smaller systems, by comparison, are more likely to be acquired through an up-front payment. A UFI can assist in lowering that up-front cost.

d. Predetermined Pricing or Market-Based Pricing

Another respect in which state incentive programs vary is whether incentives are available at a predetermined price or whether incentives are only available through participation in a competitive auction. As with UFIs versus PBIs, states often make this determination based on system size, offering a predetermined, fixed-price incentive to smaller systems while using competitive markets to determine incentive levels for larger systems. North Carolina, Colorado, Maryland, and New Jersey all use this approach.

North Carolina's NC GreenPower program offers a fixed incentive for PV systems 10 kW or smaller.[34] Colorado's IOUs offer REC-purchase incentives for PV systems less than 100 kW, which is paid in the form of an up-front rebate for 20 years of REC generation.[35] North Carolina and Colorado both use a market-based approach for larger projects, allowing PV system owners to bid RECs into an auction.

Maryland has similarly created a market-based approach to REC purchases for systems larger than 10 kW. If a PV generator opts to sell RECs, he or she must first offer to sell RECs to utilities by posting them for a minimum of 10 days on the Maryland Public Service Commission's website. New Jersey also uses a competitive purchase program for RECs from larger PV systems. New Jersey's program provides a means for solar RECs to be created and verified and requires electric suppliers to participate in this program in order to meet solar RPS requirements. In March 2009, the weighted average price of 2009 solar RECs was approximately $467/MWh ($0.47/kWh), with some trades as high as $680/MWh. New Jersey is the only state that has REC auction-price transparency, so it is hard to compare New Jersey prices with those from other regions.

IOUs in Arizona, by comparison, offer predetermined incentive payments to all grid-connected PV systems regardless of size, in addition to small off-grid systems. California also offers an administratively determined fixed-price incentive to all PV systems eligible for the state's CSI incentives. Both Arizona and California employ mechanisms to adjust incentive levels downward as PV prices decline. This captures some of the benefits of a market-based approach to setting incentive levels.

RETAIL MARKET POLICY CONCLUSIONS

Although the policies discussed in this Retail Market Policies section are varied, similarities in policy design suggest that successful retail policies have three characteristics in common:

- **Ease of Enrollment:** Successful policies allow retail customers to generate and use PV power with minimal hassle. In particular, they provide easy enrollment, minimize ongoing obligations, and avoid the creation of taxable benefits and regulatory requirements that can often accompany the wholesale power sale options discussed in the next section.
- **Benefits of Self-Generation:** Successful policies are designed to satisfy customer expectation that self-generation will result in reduced electricity purchases from an incumbent utility. Customers who generate their own power expect that a kWh of PV power that is self-generated will result in an avoided kWh purchase from their electric utility.
- **Cost Effectiveness:** Successful policies provide a value proposition that makes a PV investment cost-competitive with electricity supplied by either regulated or competitive retail electric service providers. Providing this value proposition often requires a well-considered mix of retail rate design, targeted incentives, and policy options that provide customers with the expected benefits of self-generation.

WHOLESALE MARKET POLICIES

PV system costs have dropped considerably in recent years and are expected to decline for the foreseeable future. In some markets, wholesale PV generation prices have become competitive with other sources of wholesale peaking power. California utilities, for example, have signed contracts for more than seven gigawatts of PV and concentrating solar power. Utilities in Arizona, Nevada, and New Mexico have also signed a significant number of contracts for wholesale solar capacity. As seen in Figure 2, utility-owned and commercial systems are accounting for an increasingly large percentage of installed PV capacity.

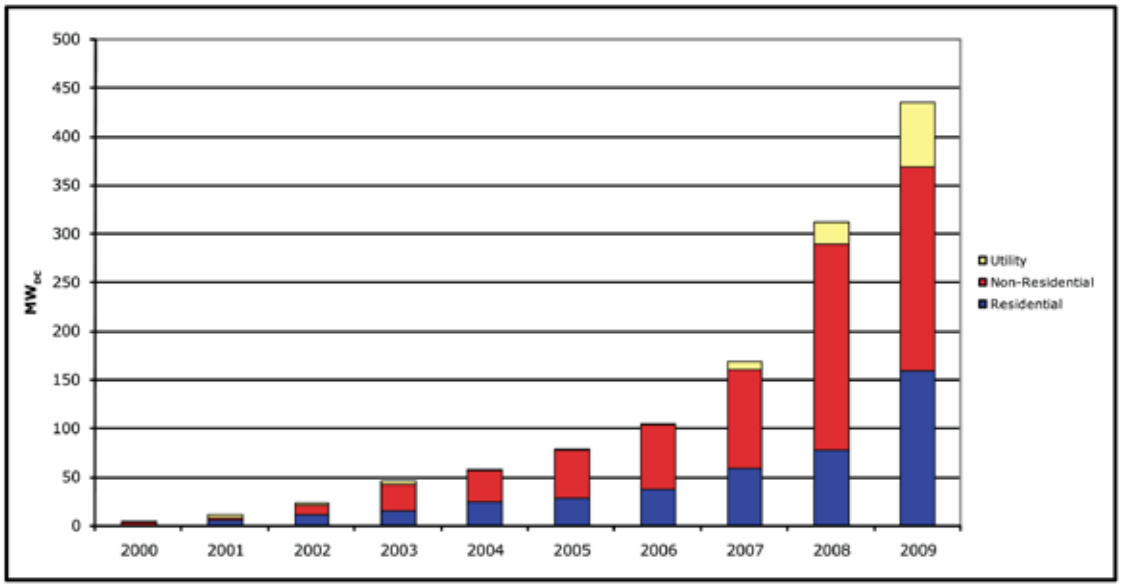

Figure 2: Annual Installed Grid-Connected PV Capacity by Sector (2000-2009)[36]

Utility motivations for entering wholesale contracts with PV facilities are varied. Cost effectiveness and peaking supply are only two of the benefits of PV. Distributed PV systems can also be deployed quickly, scaled to most any size, and sited almost anywhere. The flexibility to locate PV generation where needed, when needed, and in the size needed offers grid benefits that other sources of renewable generation cannot offer. Moreover, the smaller footprint of distributed PV systems means they can be deployed close to the loads they serve, avoiding transmission constraints and lengthy environmental review processes.

Many of these benefits are currently overlooked in utility procurement practices. However, that paradigm is beginning to shift in many markets that have seen significant retail PV market growth. Policy makers and utilities in these markets have begun to appreciate the many benefits of distributed PV systems. They have also begun to appreciate the need for targeted procurement mechanisms that fully value the range of benefits provided by PV. The result has been movement in many areas toward policies that increase procurement of wholesale power from distributed PV.

> "The flexibility to locate PV generation where needed, when needed, and in the size needed offers grid benefits that other sources of renewable generation cannot offer."

This section discusses four approaches that support distributed PV wholesale market development in the United States. These procurement mechanisms are often part of an implementation strategy for achieving identified goals, particularly technology-specific or resource-specific carve-outs within RPS policies. Most often these carve-outs take the form of solar or distributed generation targets. As evidence of this, 17 states have created solar targets within their RPS programs, and nine states have created distributed generation procurement targets or allow utilities an RPS credit multiplier for customer-sited systems.[37]

First, we discuss the wholesale market policy that has been in place the longest. Avoided cost mechanisms came into existence in 1978 when Congress enacted the Public Utilities Regulatory Policies Act (PURPA). PURPA required utilities to purchase electric generation from small power production facilities and cogeneration qualifying facilities (QFs) at a price equal to a utility's "avoided cost." Avoided cost is set at a level that reflects the lowest cost supply option available to a utility. It is often set at price that reflects the cost of generating from a conventional fuel facility, which has lead PURPA to be roundly criticized as being outdated and inadequate to achieving state policy goals. We discuss these criticisms below as well as how some states have attempted to address shortcomings of avoided cost pricing by providing additional payment for renewable attributes of power generation.

Feed-in tariffs are similar to avoided cost mechanisms in that they obligate a utility to purchase power from eligible generators at predetermined prices. However, whereas avoided cost rates are set at a level that reflects the lowest cost resource available to supply a utility, FIT pricing is technology-specific and intended to reflect a level that is sufficient to ensure that developers can build and operate a project and be profitable.

Another key difference is that avoided cost pricing is intended to hold a utility and its ratepayers indifferent to the source of power by setting price levels equal to the lowest cost resource available to supply power to a utility. By holding ratepayers indifferent to cost, PURPA could be implemented without placing a cap on program enrollment. So long as a utility needs electric power supply, it is required to buy available QF power. In contrast, FITs may set price levels well above the cost of alternative resources. To limit ratepayer exposure to higher cost sources of power, jurisdictions that have enacted FITs in the United States have all imposed caps that limit FIT system deployment on the basis of installed capacity, total cost, or allowable rate impacts.

Although avoided cost rates and FIT programs use administratively determined prices, market-based procurement uses competitive means, such as auctions and RFPs, to determine price levels. This approach provides a mechanism for choosing among eligible projects when there is more developer interest than program caps can accommodate—contracts are awarded on the basis of lowest price. A downside of this approach is that it may increase the administrative cost of obtaining a wholesale contract compared to PURPA and FIT programs that do not require participation in an auction or RFP prior to the awarding of a contract. Thus, RFP or auction-based programs may place smaller systems and emerging technologies at a disadvantage because administrative costs represent a larger percentage of project revenue than for larger PV projects.

We discuss each of these options—avoided cost, FITs, and auctions/RFPs—below.

1. AVOIDED COST

State avoided cost rates find their origins in PURPA, which was enacted against the backdrop of 1970s foreign oil embargoes of the United States. PURPA was enacted as a means of diversifying the nation's electric generation sources and was intended to reduce the nation's reliance on fossil fuels. To accomplish this goal, PURPA directed FERC to issue rules and regulations that require electric utilities to purchase energy from certain QFs, which include cogeneration and small power production facilities, including solar electric generation facilities up to 80 MW in capacity.[38]

Although Congress intended to create a market for QF power and diversify the nation's electric power resources, Congress also sought to limit electric utility and ratepayer cost exposure to purchases of QF power. In an effort to hold utilities and ratepayers indifferent to PURPA's obligations, Congress required that rates for QF purchases not exceed a utility's "incremental cost" of generation.[39] According to FERC's regulations, this means rates cannot exceed the cost the electric utility would pay for generating its own power or purchasing it from another source.[40] State regulatory authorities and non-regulated utilities establish utility-specific avoided costs, with FERC regulations leaving considerable

flexibility to state regulatory authorities and non-regulated utilities in doing so, so long as the rates that are established reflect avoided cost ratemaking principals and meet the requirements established in FERC's PURPA regulations (Independent Energy Producers Association, Inc. v. California Public Utility Commission, 36 F.3d 848, 856, 1994).

It is also important to note that the federal Energy Policy Act of 2005 (EPAct 2005) eliminated a key provision of PURPA with respect to QFs. Prior to EPAct 2005, a utility had a mandatory purchase obligation to purchase power from a QF facility at avoided cost. After EPAct 2005 took effect—in those areas where an effective wholesale market exists—utilities may be relieved of their obligation to make a purchase or enter into a contract with a QF. The thinking is that if there is an effective wholesale market, QFs will have no more difficult time selling their power in the market than any other generation source, and all generators will receive the same price for their power.

a. Variations in State Avoided Cost Programs

Avoided cost programs differ on whether they allow a customer to serve onsite energy needs. Some avoided cost programs require all customer-generated energy to be exported to the grid without allowing customers to use generation to serve onsite electrical needs. Other programs resemble net metering in that they allow customers to offset instantaneous onsite electricity needs first, before exporting excess electricity to the grid.

Regardless of whether generation may be used to offset onsite electricity needs first, what avoided cost mechanisms have in common is that all energy exported to the grid is compensated at a utility's avoided cost rate. This differs from net metering, in which most electricity exported to the grid has a retail value—the customer can use a kWh credit received for exported electricity to offset a kWh purchase. This retail value is typically well above a utility's avoided cost. The following examples may help illustrate this wholesale policy option.

Since deregulation, fully integrated IOUs serve less than 25% of the state of Texas. Integrated utilities in non-competitive areas of the state (El Paso Electric Company, Entergy Texas, Southwestern Electric Power Company, and Xcel Energy, for example) that are not under Electric Reliability Council of Texas (ERCOT) control maintain an offering for QFs up to 100 kW powered by any type of distributed generation, and to QFs up to 50 kW powered by renewable energy resources. Owners or developers of QFs have several options. They can use onsite generation to supply onsite needs and receive a utility's avoided cost rate for any energy exported to the grid. A second option is a buy-all, sell-all arrangement in which all energy generated onsite is sold to a utility with none of the generation used onsite. Under the second option, a seller may qualify for a capacity credit if a facility results in avoided capacity costs for a utility.

Another example can be found in North Carolina with Duke Energy's Small Customer Generator (SCG) Tariff.[41] Residential customers with PV systems up to 20 kW and non-residential customers with PV systems up to 1 MW or customer's contract demand, whichever is less, are eligible to participate in this arrangement. The contract demand is the maximum demand to be delivered under normal conditions to the utility customer excluding output from the customer's installed electric energy system. A generating facility may be used to offset a facility owner's electricity consumption and, if feasible, demand charges. Excess generation is then purchased by Duke Energy through a variable rate structure that adjusts every two years based on state regulatory commission hearings.

There are two options under this tariff—A and B. Option A offers a lower price per kWh of production, but has a wider range of on-peak hours. Option B offers higher rates, but uses a much more complex equation of on- and off-peak hours that results in a reduced window of on-peak periods. About half of all PV generators in Duke's North Carolina

service territory take service under the SCG rider and all of those choose option B because of the higher price for peak hours. Note that the SCG rider is not available in all states in which Duke operates. This example is taken from North Carolina's offer.

Duke Energy also offers a buy-all, sell-all option for customer generators as determined by their Purchased Power Non-Hydroelectric (PP-N) and Purchased Power Hydroelectric (PP-H) tariffs. (Hydroelectric facilities are allowed different rates based on whether or not they have energy storage capabilities.) The PP riders offer, in addition to an avoided cost payment, an energy capacity credit. There is also a possibility for long-term fixed price contracts under these buy-all, sell-all schedules.

b. Establishing Utility Avoided Cost Rates

State PUCs set avoided cost rates for utilities that fall under their jurisdiction—most often IOUs—pursuant to avoided cost rules established by FERC. Utilities that are not regulated by state public utility commissions establish their own avoided cost rates. FERC's avoided cost rules provide flexibility to allow a wide variety of approaches in setting avoided cost rates, but avoided cost may not exceed the cost an electric utility would pay for generating its own power or purchasing it from another source, [42] and the types of values that may be incorporated into an avoided cost calculation are limited by FERC's PURPA regulations.[43] So, for example, local economic and job creation benefits may not be taken into account in setting avoided cost rates. This limits the extent to which avoided cost rates can be set at a level sufficient to allow all potential generation sources to operate profitably while selling under avoided cost rates.

There are many ways to set avoided cost rates. For example, FERC has recognized that competitive bidding can be a valid way for a state commission to determine the avoided cost of generation by ascertaining the market value of the next incremental addition to capacity.[44] However, if avoided cost rates are determined by competitive bidding, all sources of generation available to a utility must be able to participate in the competitive bidding. Participation cannot be limited to QFs or particular types of generators.[45] These rules make it impractical to develop avoided cost pricing that reflects the value of renewable energy purchases, which can often be higher in price than conventional fuel generation. Other means of setting avoided cost include use of a proxy plant, administrative determination, or tying to a market index.[46]

Determining the price level of a utility's avoided cost can be difficult and state rulemakings aimed at determining avoided cost can be contentious. Utilities often calculate avoided cost as the cost of future production by the next plant to come online (often an inexpensive combined-cycle plant) and add that to the average price of different types of fuel costs (rather than using only what the combined cycle would actually use, natural gas). Furthermore, this price does not include administrative or transmission and distribution costs that the utility incurs in the delivery of power. As a result, avoided cost is often significantly lower than a utility's fully bundled retail rate.

True avoided cost prices are not widely publicized, but information from a number of sources, such as *Avoided Energy Supply Costs in New England: 2009 Report*,[47] estimate that they range around from about 30% to 50% of a utility's retail price. Avoided cost is typically well below the price a utility may otherwise pay for renewable power through FITs or targeted RFPs issued in connection with RPS or distributed generation procurement, both of which are discussed in the following subsections.

A final consideration that is important with respect to avoided cost procurement is the extent to which additional fees and charges, such as standby charges, may be assessed on customers participating in such programs. Duke Energy's Rider SCG contains standby charges of $1.11/kW that apply to systems larger than 100 kW.[48] This charge is based on the installed capacity of a system and is assessed regardless of whether a system operates at full rating during a billing period or whether a retail customer sees any

reduction in demand charges after installing a PV system.

For customers with intermittent generation, standby charges can be duplicative of charges that a customer-generator pays through demand charges on his or her electricity bill. Standby and demand charges both compensate a utility for investments in installing and maintaining facilities needed to provide electric utility service. In other words, charging a customer both standby and demand charges can result in a double billing for maintaining the same facilities.

c. Is PURPA Relevant Now That States Have Enacted RPS Standards?

PURPA was enacted in 1978, well before states began implementing RPS standards that require utilities to procure a certain percentage of their power from renewable resources. RPS programs recognize that the cost of generation for renewable resources is different—and can be higher—than the cost of generation using conventional resources. Rather than allow price alone to determine the appropriate composition of a utility's generation portfolio, RPS policies determine a minimum percentage of a utility's portfolio that must be supplied by renewable generation of various types. It also allows the identified renewable resources to compete to satisfy that requirement, even if the price paid for the renewable generation exceeds the price that may otherwise be paid for generation from conventional resources.

In addition, a number of states have sought to further diversify utility generation portfolios to include larger amounts of distributed generation resources. As we noted earlier, seventeen states have created solar generation targets within their RPS programs and nine states have created distributed generation targets or have allowed utilities a RPS credit multiplier for customer-sited systems.[49] As a result of these programs, utilities now routinely procure electric generation and RECs in sub-markets that may feature different market clearing prices. Establishing a single procurement method or price to achieve multiple program procurement goals does not reflect this market reality.

This has led many renewable energy advocates to criticize PURPA as providing a price that is not designed to accomplish the myriad environmental and fuel diversity goals that have been put in place since PURPA's enactment in 1978. They claim that PURPA procurement is intended to hold ratepayers indifferent to the source of power, whereas RPS and targeted procurement programs are designed to ensure that a utility pays what is necessary to meet customer supply needs with identified percentages of power from renewable resources. Criticisms such as these have led policy makers in many areas of the country to adopt targeted wholesale procurement mechanisms that support renewable power development and enable states to meet their renewable power policy goals.

d. Supplementing Avoided Cost with Payment for Renewable Attributes?

A utility's avoided cost of meeting identified procurement goals, such as those adopted through RPS policies, may be quite different than a utility's avoided cost of meeting the demands of its customers with the lowest cost resource available to serve that demand. As discussed above, it also seems fair to question whether conventional fuel resources like oil and natural gas should be used to determine avoided cost compensation levels for PV and other renewable resources, given that these resources have different supply characteristics, have different costs of generation, provide price stability benefits when under long-term contract, and provide environmental benefits beyond what avoided cost rates are intended to reflect.

To the extent a utility faces actual, quantifiable costs associated with environmental compliance requirements, those costs may be included in an avoided cost determination. However, such costs can be very difficult to quantify, particularly with regard to greenhouse gas emissions, an area in which regulatory regimes and compliance costs are

still being determined. Avoided cost rates are also technology neutral and not designed to help achieve policy goals such as diversifying generation resources, promoting customer investment in renewable energy, delaying or avoiding transmission upgrades, achieving renewable portfolio standard goals, reducing greenhouse gas emissions, or any number of other policy goals.

> "... it also seems fair to question whether conventional fuel resources like oil and natural gas should be used to determine avoided cost compensation levels for PV and other renewable resources, given that these resources have different supply characteristics, have different costs of generation, provide price stability benefits when under long-term contract, and provide environmental benefits beyond what avoided cost rates are intended to reflect. ."

Avoided cost programs such as Duke's Rider SCG appear to recognize that avoided cost rates do not provide adequate compensation for the unique costs and benefits of renewable and distributed power generation. Duke's program allows participating customers to sell RECs associated with Rider SCG and Rider PP-N and PP-H generation into North Carolina's NC GreenPower incentive program. This allows customers to receive compensation in addition to avoided costs for a customer's contribution toward helping North Carolina achieve its renewable power policy goals.

Providing an avoided cost payment for wholesale power and supplementing that with a REC payment that reflects the market price of renewable energy attributes can be a viable approach to supporting wholesale market development of renewable and distributed generation. However, an important consideration is whether this approach is authorized under state law. Whether RECs are created or conveyed in an avoided cost transaction is left to state discretion.[50] If RECs are not conveyed in an avoided cost transaction, they may be sold through a state incentive program or a REC purchase program. However, that is not always the case, and state law should be reviewed carefully to determine whether a REC purchase program may be used to supplement avoided cost pricing. In California, state public utility statutes state that, "no renewable energy credits shall be created for electricity generated under any electricity purchase contract executed after January 1, 2005, pursuant to the federal Public Utility Regulatory Policies Act of 1978."[51] This may preclude QFs in California that are participating in avoided cost programs from selling RECs to utilities for RPS compliance, because those RECs are essentially considered to have been conveyed in the underlying avoided cost sale.

2. RENEWABLE ENERGY CREDIT MARKETS

As discussed in the Retail Market Policies section of this paper, most state performance-based and up-front incentives for PV systems are only available for systems that produce energy that is used for onsite consumption. Systems that sell power under a wholesale arrangement, such as an avoided cost program, are often unable to receive PV incentive payments. California's CSI incentive program is an example of an incentive program that is only available for PV systems that supply power to onsite load, with any excess generation credited under a net-metering program. Wholesale generators may not receive CSI incentives.

Although wholesale generators may not take advantage of PV incentives in California and other states, some states have established markets that allow PV system developers to sell RECs to utilities who may then use those RECs for RPS compliance purposes. In some states, RECs may be used to meet identified solar and distributed generation procurement and load service policy goals. For example, Arizona, North Carolina, Colorado, and New Jersey all allow systems selling power under wholesale arrangements to sell their RECs to a utility to meet identified solar and distributed generation requirements. Through the use of these programs, PV system developers may be able to

supplement an avoided cost payment with a REC payment so that overall compensation more accurately reflects the market price of PV generation, thereby ensuring that procurement mechanisms are designed to achieve policy goals. For this approach to be viable from a project development standpoint, it is critical that payment for RECs be offered through a long-term contract so that the income stream from RECs is sufficiently stable to allow for project financing.

For wholesale generators participating in programs other than avoided cost mechanisms, RECs are typically conveyed to a utility as a part of a wholesale power transaction. For example, California, Vermont, and Hawaii all require a transfer of RECs as a requirement for participating in their state FIT programs (discussed below). On the other hand, and to underscore the diversity of incentive programs, several municipal utilities in Washington and Alaska offer payment for energy fed onto the grid from renewable energy systems up to 25 kW. These municipal programs do not specify the inclusion of RECs in the payment. In this case, a system owner has the option of retiring RECs or selling them to a willing purchaser. The amount paid to participating renewable energy producers depends on the total amount contributed by local financial supporters, but cannot exceed $1.50/kWh. In 2009, the Chelan County Public Utility District's program was offering $0.22/kWh, and the Okanogan County Public Utility District, also in Washington State, was offering $0.198/kWh. Golden Valley Electric Association in Alaska provides an annual payment based on contributors' participation in the program.

Wholesale generators are also eligible for other incentives that this paper does not address, such as tax credits, grants, and low-cost loans that can have a significant impact on the cash-flow analysis of a project.

3. FEED-IN TARIFFS

A FIT is an obligation that is placed on an electric utility to purchase wholesale electricity from an eligible seller of electricity at specified prices. FIT prices are administratively determined and are typically set at a level that is intended to be sufficiently high to attract the types and quantities of renewable energy desired.

In many ways, FITs are a logical evolution of PURPA's compelled-purchase requirement for utilities. They provide the administrative ease and certainty of a PURPA "must buy" program, but adopt higher prices that are more akin to price levels associated with renewable energy purchases obtained through RPS procurement mechanisms.

Recent movement toward FITs for distributed PV systems appears to be motivated by four considerations: (a) a desire to support investment in larger PV systems beyond those that primarily serve onsite load; (b) a recognition that existing wholesale procurement mechanisms tend to favor very large generators to the near exclusion of distributed systems; and (c) an appreciation that distributed generation has benefits that may justify a higher price than is paid for larger grid-scale power projects; and (d) a perception that FIT programs have brought large amounts of distributed PV capacity online in European countries such as Germany and Spain.

At present, policy makers in most states in the United States are limited in their ability to adopt FITs for IOUs at rates that exceed utility avoided cost. Congress has vested FERC with exclusive authority over wholesale markets. FERC has determined that state authority to determine wholesale market prices is limited to implementing PURPA and determining avoided cost prices for QFs.[52]

There are three important exceptions. First, the states of Alaska, Hawaii, and Texas are not subject to FERC's wholesale pricing authority, and so policy makers in these states may set wholesale electricity prices in excess of avoided cost. Second, municipal or publicly owned utilities are not subject to FERC oversight and so state legislatures (and public utility

commissioners in states where state utility commissioners have jurisdiction over municipal utilities and electric cooperatives) may require such utilities to adopt FITs at prices that exceed avoided cost. Third, state policy makers can establish a FIT that exceeds avoided cost if a state provides an incentive, tax credit, or REC payment to compensate for the portion of a tariff that exceeds avoided cost.

The above limitations make FIT policies a limited wholesale market option in much of the United States. However, because FITs are potentially feasible in some locations, the following subsections discuss the limited FIT programs that have been implemented and the methods that have been applied to determine FIT rates.

a. *Existing State and Utility Feed-in Tariff Programs*

Although there has been much discussion in the United States about establishing FITs at a federal, state, or local level, few have actually been implemented. Gainesville Regional Utility (GRU), a publicly-owned utility in Florida, made news in early 2009 when it arguably became the first utility in the United States to adopt a FIT. GRU's program, capped at 4 MW per year, features rates starting at $0.26 for systems larger than 25 kW and $0.32/kWh for systems less than 25 kW, and ramps down each year until 2016.[53]

Other municipal utilities have also proposed and/or implemented FIT programs. The Sacramento Municipal Utility District (SMUD) recently implemented a FIT program that is capped at 100 MW of qualifying renewable and combined heat and power generating facilities. The SMUD FIT targeted systems up to 5 MW and the application queue to meet SMUD's procurement target was filled within a day, all with PV capacity.[54] The SMUD tariff is based on a time-differentiated avoided cost calculation, but rates are levelized and locked in for the life of a power purchase agreement.[55] Estimates show that expected PV output under the time-differentiated levelized rate would be about $.14/kWh with a 20-year term.

Other utilities that have adopted voluntary FITs include San Antonio's municipal utility (CPS Energy) and Indianapolis Power & Light.[56] Because these are voluntary programs that are merely approved and not compelled by state or local policy makers, they are not preempted by FERC.

There has also been activity at a state level, most notably in Vermont, Hawaii, and California. In May 2009, Vermont enacted a law that requires all retail electricity providers to purchase renewable electricity through a Sustainably Priced Energy Enterprise Development Program.[57] This program provides long-term contracts with fixed standard offer rates for renewable energy fed into the grid, capped at 50 MW of installed capacity. In 2009, the Vermont Public Service Board adopted interim prices for this program that included $0.30/kWh for solar installations up to 2.2 MW.[58] The technology-specific cap of 12.5 MW was maxed out the first day applications were accepted. However, if any of those projects are not built, further contracts may be issued at $0.24/kWh.[59]

In October 2009, the Hawaii PUC issued a decision and order outlining general principles for the creation of a statewide FIT to be offered by the state's IOUs.[60] The FIT will offer a fixed rate over a 20-year contract and will allow projects up to 5 MW for Oahu, and up to 2.72 MW for Maui and Hawaii Island. Hawaii's FIT is capped at 5% of 2008 peak demand over a 3-year period. The Hawaii legislature also passed legislation in 2009 that allows the PUC to set preferential prices for renewable energy from agricultural lands.[61] Hawaii is not subject to FERC's wholesale pricing authority, and so FIT rates in Hawaii may exceed utility avoided cost.

California enacted a limited FIT in 2006 that applies to RPS-eligible generators less than 1.5 MW in capacity and does not feature pricing that is differentiated by generation source.[62] This legislation was amended in 2009 to increase eligible system size to 3 MW for participating generators and to expand statewide enrollment limits.[63] Under the current

program, generators may enter into 10, 15, or 20-year contracts and receive a payment based on an administratively determined market price referent (MPR), a benchmark price that the CPUC uses to determine price reasonableness in annual RPS solicitations.[64]

Because California's MPR is based on the projected 20-year levelized cost of building a new combined-cycle natural gas turbine, it represents the long-run avoided cost of new gas-fired generation, and is therefore more of an example of an avoided cost implementation than a FIT. As such, the ability to require California utilities to offer this price may be found under California's authority to implement PURPA. California's MPR-based tariff is available until the combined statewide cumulative capacity of eligible installed generation equals 750 MW.[65]

b. Establishing Feed-in Tariff Rates

Designers of FITs typically aim to provide a payment level that is sufficiently high to spur renewable development. There are basically two approaches to determining a market-clearing price for renewable and/or distributed generation. FITs use an administratively determined price. Auctions and RFPs, by comparison, use market mechanisms to establish a price. Another important difference is that in a capped program, FITs use a first-come, first-served approach to rationing available capacity while auctions and RFPs ration available capacity on the basis of achieving the lowest cost to ratepayers.

Determining electricity prices administratively can be a challenging task. In the section on Avoided Costs we mentioned that determining the price level of a utility's avoided cost can be difficult and state rulemakings aimed at determining avoided cost can be contentious. Many of the FIT programs that have been implemented in the United States have involved publicly owned utilities or were offered voluntarily by an IOU. It remains to be seen whether setting and adjusting FIT rates in states such as Vermont and Hawaii, which have imposed FIT obligations on utilities, proves to be contentious.

In the long term, establishing and adjusting FIT rates could prove to be more labor intensive than setting an avoided cost rate. Technology-differentiated tariffs could prove particularly challenging to implement, because a standardized cost of production would need to be determined for all participants in a FIT program. Most FIT programs are structured to offer targeted pricing that varies depending on the renewable generation source—solar, wind, biomass, biogas, etc.

Costs of production can also vary significantly within each of these generation sources. For example, a number of technologies exist for converting solar resources into electric energy, with varying costs of generation. Cost of generation can also differ for a single technology based on where a generator is located and how it is installed. For example, a ground-mounted PV system in an inland location in California will certainly have a different cost of generation than a roof-mounted system installed along the foggy Northern California coast, even if the same PV panel technology is used.

A FIT price that adequately compensates one installation may under- or overcompensate another installation, and a FIT price that aims to compensate all of these installations may generate interest that exceeds program availability, which has been the case with all FIT programs implemented in the United States thus far. For example, Vermont's FIT set an initial price for solar technology of $0.30/kWh and generated contract requests totaling 175 MW for 12.5 MW of available capacity (Wilson, 2009). This led some to question whether the same amount of solar capacity could have been installed at a lower cost (Graham, 2009). Feed-in tariffs offered by GRU, SMUD, and CPS Energy also resulted in significantly more interest than initial program caps could accommodate on the first day tariffs were available (Yarrow, 2009).

By comparison, California implemented a FIT program in 2007[66] that was based on the administratively determined MPR. Compared to GRU and Vermont, which set prices that resulted in too much interest, the California program set price at a level that under-stimulated participation. What this illustrates is that it can be difficult to administratively

determine a price that simultaneously guarantees developers an opportunity to operate profitably and procures wholesale power at the lowest cost to ratepayers.

Although it can be administratively difficult to determine appropriate price levels, feed-in and fixed-price tariffs, like avoided cost tariffs, are likely the most efficient means to enroll projects quickly. FITs provide price-transparency to developers and therefore enable a good projection of project revenue prior to incurring any costs in developing a site or installing a system. Market-based mechanisms that feature an RFP or auction, by comparison, may require project development expenditures, such as obtaining a site control agreement or an interconnection request, prior to obtaining a power sale contact.

> "... feed-in and fixed-price tariffs, like avoided cost tariffs, are likely the most efficient means to enroll projects quickly."

One way of addressing the difficulty of administratively setting FIT rates is to predetermine a market-responsive payment digression method that adjusts the level of FIT rates at predetermined time intervals or once predetermined thresholds—installed capacity, as one example—are met. California's CSI incentive program adjusts incentive levels when installed capacity goals are achieved. This approach is particularly well suited to setting prices for technologies such as PV, which are experiencing rapidly declining costs. This approach may not work as well for technologies where costs are not decreasing rapidly or may even increase, which could conceivably apply to any technology, including PV. To ensure that prices can adjust upwards, FIT price adjustments could instead be linked to a market-index such as one resulting from an RPS solicitation for renewable generation.

Despite the potential benefits of FITs, state policy makers in the United States are presently limited in their ability to establish an administratively determined price for wholesale power that exceeds a utility's avoided cost. Outside of Hawaii, Alaska, and Texas, FIT obligations may only be imposed on municipal utilities and electric cooperatives, unless payment in excess of avoided cost is provided through a REC payment or is credited through tax and/or incentive mechanisms, or when a FIT is voluntarily offered by a utility.

4. MARKET-BASED PROCUREMENT METHODS (RFPs/AUCTIONS)

Rather than set wholesale prices administratively, as is done with avoided cost rates or FITs, state policy makers can instead use market mechanisms, such as auctions or RFPs, to determine a price appropriate to meet an identified procurement requirement. Several state policy makers have used this approach to establish REC prices, avoided cost rates, wholesale power prices, and renewable power prices pursuant to RPS procurement. In fact, market-based methods are the predominant means of wholesale power procurement in the United States. This approach incentivizes market entry by higher efficiency generators and ensures prices that support development and produce the least cost for ratepayers.

In the remainder of this report, we provide several examples of RFP programs that are targeted toward PV procurement. We also discuss some disadvantages of RFPs that may make such policies better suited for larger systems.

a. Existing State and Utility Targeted RFP Programs

On June 18, 2009, the CPUC authorized Southern California Edison (SCE) to implement a 500 MW PV program.[67] This program allows SCE to build, own, and operate 250 MW of PV capacity and procure an addition 250 MW from independent power producers (IPPs) through a competitive bid program targeted at PV systems in the 1 to 2 MW capacity range. The program will focus on developing PV systems on commercial rooftops. Ground-mounted generation may account for up to 10% of the competitive solicitation. SCE will hold two competitive solicitations per year, with contracts awarded to bidders who meet minimum project viability standards, pass several specific screening criteria, and offer the lowest price. If a bid is selected, SCE and the seller may then enter into a standard, non-negotiable contract.

On April 22, 2010, the CPUC authorized Pacific Gas & Electric (PG&E) to develop up to 500 MW of PV over five years, consisting of projects between 1 and 20 MW.[68] PG&E will own up to 250 MW of PV and procure an additional 250 MW from IPPs through competitive solicitations. PG&E will develop projects at a rate of approximately 100 MW per year (50 MW per year for each portion). Successful bidders for the IPP portion will enter into standard, 20-year power purchase agreements (PPAs) with PG&E.[69]

On July 13, 2010, the CPUC issued a proposed decision that would authorize San Diego Gas & Electric (SDG&E) to develop 56 MW of PV over a five-year period.[70] SDG&E is authorized to own up to 26 MW of PV generation, while IPPs will own the remaining 26 MW. The program would have a spending cap of $250 million and will focus on 1 to 2 MW projects. SDG&E will hold a competitive solicitation at least once per year. Pricing for the solicitations will be capped at $235 per MWh, which is based on an installed cost of $3.50/W. Projects must achieve commercial operation within 18 months.

The CPUC is also considering a proposed decision that would create a renewable auction mechanism for renewable generators from 1 to 20 MW in capacity that would contribute to California's RPS goals.[71] The program would require California's three largest IOUs to hold periodic auctions separately from the general RPS procurement process that is required annually. This would allow smaller projects to compete among themselves on price rather than competing against larger projects in the annual RPS solicitation. Developers would submit non-negotiable bids for long-term contracts and lowest-cost projects that meet specific viability criteria would be awarded contracts. Sellers must bring a project online within 18 months (with extensions available for delays that occur through no fault of a developer). The program would be capped at 1,000 MW and procurement would be spread over a four-year period.

Arizona and Oregon have moved forward with market-based wholesale procurement programs that target distributed PV systems. In 2008, Arizona Public Service (APS) created an RFP program for DG projects to meet an annual DG procurement goal of 200,000 MWh. APS received offers from 12 bidders who submitted 22 qualified proposals that exceeded the target capacity nearly three times over.[72] Another large Arizona utility, Salt River Project (SRP), has also issued an RFP targeted at distributed PV.[73] SRP will procure up to 50 MW of ground-mounted PV capacity in the third quarter of 2012 and up to 50 MW in the third quarter of 2013. SRP has indicated a particular interest in projects between 5 and 20 MW in capacity to be located in the Phoenix metropolitan area.

In Oregon, the PUC recently approved a market-based procurement mechanism for PV systems between 100 kW and 500 kW in capacity.[74] Oregon utilities Pacific Power and Portland General Electric have subsequently issued RFPs to accept competitive bids pursuant to this program.[75]

b. Establishing Market-Based Rates

Market-based procurement mechanisms, such as auctions and RFPs, are more likely to capture market price fluctuations than an administratively derived price. This is primarily due to sellers in the market having more information than regulators, because sellers have a better understanding of their costs and means of mitigating them. Market participants are also able to optimally design the size a facility to maximize economies of scale appropriate to their particular capabilities and project locations.

Assuming a market participant bids a price that is sufficient to satisfy his or her financial objectives for developing a project, the price achieved through a market-based procurement mechanism should be sufficient to financially support the project. However, this is not always the case. Developers may lack experience and unintentionally underbid the price necessary to bring a project to financial viability. There is also a possibility that unanticipated circumstances may lead project development costs to exceed diligent cost

projections and may therefore leave a project unable to operate profitably despite the anticipated viability of the price bid.

Of course, the risk of cost overruns and lack of experience in understanding project development costs are not problems that are unique to participation in market-based procurement programs. These challenges may also arise in programs that use an administrative approach to determining a fixed price.

Large projects are complex endeavors that require a significant amount of sophistication regarding permitting, environmental requirements, interconnection, financing, taxes, regulatory approvals, and a plethora of other issues. It seems reasonable to expect that market participants developing projects above a nominal size should have the sophistication necessary to forecast costs and meet delivery obligations agreed upon under a power sale arrangement.

To ensure that participants have the experience necessary to develop a project and that a developer can meet financial obligations arising under a wholesale contract, California's targeted RFP programs all require bidders to satisfy minimum project viability prerequisites. Developers are also required to post reasonable development security, which acts as a deposit that is returned if a project achieves commercial operation within identified timeframes, but is forfeited if a project does not achieve a minimum level of commercial operation.

Although market-based procurement mechanisms can facilitate procurement at lowest cost to ratepayers, and can be implemented without the difficulty of administratively determining a price, market-based procurement also has disadvantages, particularly for developers and installers of smaller systems. Specifically, these mechanisms offer no up-front certainty regarding the price level that may be obtained. Additionally, bidders in market-based procurement programs must incur development and transaction costs prior to submitting a bid. Having to incur these initial costs without any certainty of project revenue can make participation difficult, particularly for developers of small systems that will generate less revenue from which to repay those costs. It can also be difficult for small projects to compete on price against larger projects that may realize larger economies of scale. In light of these considerations, market-based procurement methods may be better suited for procurement from developers of larger generation facilities. Notably, the California market-based programs discussed above target systems larger than 1 MW.

WHOLESALE MARKET POLICY CONCLUSIONS

As with retail market policies, key similarities help identify essential components of successful wholesale market policy:

- **Financial incentives:** Successful programs provide a level of payment that ensures PV systems may be developed and operated profitably while limiting cost exposure of ratepayers.
- **Streamlined procurement processes:** Successful programs employ a streamlined procurement process that lowers the transaction costs of obtaining a wholesale contract while also ensuring that the most viable and cost-effective projects move forward.
- **Creating sustainable markets:** Successful programs create sustainable markets that avoid boom-bust development cycles, promote cost reduction, and capture cost reduction through market-responsive pricing mechanisms.

RECOMMENDATIONS

The terms net metering, community solar, feed-in tariff, and incentive imply more uniformity than in fact exists in state PV policies. State net-metering policies take different approaches with regard to compensating PV system owners for monthly and yearly excess generation. Community solar policies use a variety of billing mechanisms to facilitate participation and distribute benefits to the participants. Feed-in tariff prices have been set using various approaches, and state incentive programs come in a number of different shapes and sizes.

Table 2 shows which of the policies discussed in this paper have been adopted in the top 10 states for installed PV capacity.

State	Installed MW	Net Metering	Community Solar	Meter Aggregation	Incentive	Avoided Cost	Wholesale Option
1. California	528	yes	VNM	limited	UFI, PBI	yes	FIT, RFP
2. New Jersey	70	yes		pilot program	UFI	yes	RECs
3. Colorado	36	yes	VNM		RECs	yes	RFP
4. Nevada	34	yes			UFI	yes	
5. Arizona	25	yes	?	under consideration	UFI, PBI	yes	FIT, RFP
6. New York	22	yes			UFI	yes	
7. Hawaii	14	yes			UFI	yes	FIT
8. Connecticut	9	yes		under development	UFI	yes	
9. Oregon	8	yes		yes	UFI/PBI	yes	RFP
10. Massachusetts	8	yes	VNM		UFI	yes	Backstop auction

Table 2: Policy options employed by the top 10 solar states. Acronyms include: Virtual net metering (VNM), feed-in tariff (FIT), request for proposals (RFP), up-front incentive (UFI), performance-based incentive (PBI), renewable energy credit (REC), volumetric incentive rate (VIR)

Table 2 illustrates that many of the top 10 states for installed PV capacity have implemented a range of policies to facilitate growth in both retail and wholesale PV markets. The table also illustrates that the policies discussed in this paper are not alternatives but rather are complementary policies that facilitate PV growth in different market segments.

Retail Market Recommendations

Given the widespread implementation of net metering policies across the United States, it appears many state and local policy makers have embraced net metering to facilitate investment in onsite PV systems. Net metering allows utility customers who are able to host an onsite PV system to receive a simple, direct and timely financial benefit in the form of a reduced utility bill.

To make PV investment a cost-effective option for retail customers, many states have also implemented a well-balanced mix of net-metering policy, retail rate design and financial incentives. As discussed in the Retail Market Policies section of this paper, TOU rates, in particular, send a clear price signal that encourages efficient energy use and increases deployment of clean PV resources. However, to be effective, TOU rates must contain low demand charges and have a relatively high on-peak to off-peak price ratio. This creates an incentive for net-metered customers to lower consumption and increase generation to the maximum extent possible during all on-peak periods.

Although TOU structures with low demand charges and high on-peak to off-peak pricing ratios are likely to be financially attractive to many utility customers, retail tariff choice is also important, particularly for customers with PV systems that are sized to serve a small percentage of onsite electricity needs. Rate impacts and cross-subsidy concerns can be addressed in utility rate cases where the lower cost of servicing net-metered customers and the benefits of customer investment in distributed PV generation can be taken into account.

To supplement retail market policies, well-designed meter aggregation and community solar programs can extend the simple, direct, and immediate financial benefit associated with net metering to customers who are not able to host an onsite system for any number of reasons. Virtual net metering, in particular, appears well suited to facilitating investment by community members who would like to make a commitment to solar generation but lack the ability to host an onsite system. Utility billing systems, however, must be capable of dealing with complex financial arrangements that might be required for such an agreement.

Finally, a key consideration for state and local policy makers in designing successful community solar programs is allowing community participants to take advantage of incentive programs that are available for onsite generation. It is also important to ensure that a variety of financing options are available to customers looking to invest in a community system, including direct ownership, third party financing and utility ownership.

Wholesale Market Recommendations

Wholesale procurement mechanisms, like FITs, auctions, and RFPs, appear well suited to facilitating development where there are no onsite energy needs. In such situations, wholesale procurement represents the only option that allows a PV system installation to move forward. The key question for policy-makers is what is the right wholesale market design?

Given the pros and cons of fixed-pricing versus market-based pricing, which is discussed in the Wholesale Market Policies section of this paper, it appears fixed-price procurement mechanisms are more appropriate for smaller systems and market-based procurement mechanisms, such as auctions and RFPs, are better suited for larger wholesale systems. This recommendation is reflected in a recent National Regulatory Research Institute (NRRI) report (Pollock and McNamara, 2010). The NRRI report recommends that state policy makers "[e]mploy competitive bidding for larger projects, initially limiting the feed-in tariff to smaller projects."

Fixed-price wholesale offerings can be structured as an avoided cost payment plus a payment for RECs or a fixed-price for wholesale power and environmental attributes combined. However, the latter option is only viable in Alaska, Hawaii, or Texas, or in connection with approval of voluntary utility proposals, or if imposed solely on municipal or publicly-owned utilities that are not subject to FERC's exclusive wholesale pricing authority. Accordingly, state policy makers in most jurisdictions will need to structure fixed-price wholesale offerings by combining an avoided cost payment and a REC payment.

Although PURPA avoided cost programs exist in all of the top 10 states for installed PV, very little PV capacity is currently being installed under PURPA avoided cost rates alone. Avoided cost rates reflect the price level associated with the lowest-cost resource available to sell to a utility and are not intended to reflect market costs for renewable generation and are likely inadequate to facilitate growth in PV markets.

For this reason, policy makers may wish to structure avoided cost programs so that renewable qualifying facility sellers may sell the environmental attributes associated with their power production via RECs to utilities or other third parties. State policy makers may also wish to develop valuation methodologies that add to avoided costs, avoided line losses,

and deferred or avoided transmission and distribution system investments so that avoided cost rates reflect the full value of energy and capacity that PV systems provide.

RFPs and auctions are more appropriate for larger systems that involve sophisticated system integrators who have the ability to successfully estimate system costs and have the capability to quantify all costs and benefits into a successful bid. This paper does not attempt to determine the difference between "big" and "small" PV systems for the purpose of determining when market-based versus fixed-price approaches are more reasonable. State policy makers are sure to have their own conception of that difference. For example, California's targeted market-based procurement mechanisms, which are discussed in the Market-Based Procurement Methods section of this paper, target systems 1 MW and larger. Likewise, the Arizona Corporation Commission recently proposed a comprehensive approach to wholesale distributed generation market development that would use fixed-priced arrangements for systems less than 1 MW and market-based procurement for systems larger than 1 MW.[76] Oregon, on the other hand, recently implemented a market-based procurement mechanism for systems between 100kW and 500kW.[77] Thus, what constitutes a small or large PV system varies from state to state.

Regardless of the approach taken to establish wholesale prices, there are certain key elements that have proven essential to successful wholesale market policies. Leading elements are streamlined interconnection procedures, standard power sale contracts, and reasonable development security requirements. These added elements reduce transaction costs associated with project development while also helping to ensure that only viable projects should move forward.

Incentive Policy Recommendations

State incentive programs have the potential to spur investment across multiple markets and are complementary to many of the policy options that have been described in this paper. State incentive programs typically provide up-front, fixed-price incentives for smaller PV systems and performance-based incentives, paid over an extended period of time, to larger PV systems. Many states have structured incentive levels to decline at pre-determined rates over time as PV costs move lower. Many states also use market-based mechanisms to determine which larger PV systems will receive performance-based incentive payments. Regardless of the pricing mechanism used, it is important that incentive payments be firm over an extended period of time, perhaps five years or more, in order to facilitate PV system financing and "bankability."

> "... it is important that incentive payments be firm over an extended period of time, ... in order to facilitate PV system financing and "bankability. ."

Final Recommendations

Although the contours of policy design may vary within the policy categories discussed in this paper (net metering, meter aggregation, community solar, incentives, avoided cost, REC markets, FITs, auctions, and RFPs), there are three ingredients that appear essential to establishing robust retail and wholesale markets for PV systems at a state level.

First, successful market design makes investment in a PV system cost-effective by closing the gap between PV system costs and relevant retail or wholesale cost-effectiveness benchmarks. In retail PV markets, cost-effectiveness occurs when the levelized cost of PV is at or below the retail rates offered by a retail electricity provider. In wholesale PV markets, cost-effectiveness occurs when the the cost of PV production reaches wholesale power prices with similar hourly supply characteristics—that is, daytime generation that is located in proximity to end-use retail electric loads. Achieving cost-effectiveness often requires implementation of a well-considered mix of the policies discussed in this paper.

The second key ingredient is that successful policies provide market participants with clarity and stability regarding the financial benefits that will result from a PV system investment. Clarity and stability are particularly important to facilitating PV system investment because the initial investment cost of a PV system is considerable and the benefits of that investment will manifest themselves over an extended period of time. Without transparency and predictability regarding the financial benefits that will result from an investment, market participants will lack the ability to make an economically rational assessment when evaluating a PV system investment opportunity.

Third, successful policies structure retail rates to reflect the actual costs and benefits provided by customers who invest in PV systems to meet their onsite electrical energy needs (including transmission costs that may or may not be avoided/added) so as to facilitate wise choices that drive PV markets in a direction that can most quickly move away from incentives.

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Acronyms

APS	Arizona Public Service
CPUC	California Public Utility District
CSI	California Solar Initiative
EPAct 2005	Energy Policy Act of 2005
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FIT	feed-in tariff
FKEC	Florida Keys Electric Cooperative
GRU	Gainesville Regional Utility
IPP	independent power producers
IREC	Interstate Renewable Energy Council
kW	kilowatt
kWh	kilowatt-hour
LBNL	Lawrence Berkeley National Laboratory
MPR	market price referent
MW	megawatt
NEG	net excess generation
NREL	National Renewable Energy Laboratory
PBI	performance-based incentive
PG&E	Pacific Gas & Electric
PP	Purchased Power
PPA	power purchase agreement
PUC	Public Utilities Commission
PURPA	Public Utilities Regulatory Policies Act
PV	photovoltaic
QF	qualifying facility
REC	renewable energy credit
RFP	request for proposal
RPS	renewable portfolio standard
SCE	Southern California Edison
SCG	Small Customer Generator
SDG&E	San Diego Gas & Electric
SMUD	Sacramento Municipal Utility District
SRP	Salt River Project
TOU	time of use
UFI	up-front incentive
VIR	volumetric incentive rate
VNM	virtual net metering

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Solar American Board for Codes and Standards Report

Understanding the CAL FIRE

Solar Photovoltaic Installation Guideline

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February 2011

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EXECUTIVE SUMMARY

Photovoltaic (PV) systems present unique hazards for firefighters. In a building without a PV system, firefighters can disconnect the utility alternating current (AC) service to protect themselves from electric shock during fire suppression activities. When a PV system is present, however, the situation is not as straightforward, and the PV system can pose dangerous and even fatal risks to firefighters.

In August 2007, the California Department of Forestry and Fire Protection's (CAL FIRE's) Office of the State Fire Marshal began developing guidelines for the construction of PV systems in California to address these risks. It organized a task force of fire service and solar industry representatives, building officials, and codes and standards experts, which released the *Solar Photovoltaic Installation Guideline* on April 22, 2008. The *Guideline* is available as a free download at http://osfm.fire.ca.gov/pdf/reports/solarphotovoltaicguideline.pdf.

The purpose of the *Guideline* is to help firefighters identify PV systems, protect electrical wiring, and safely access roofs for vertical ventilation operations during fire suppression activities. The *Guideline* includes guidance about clearly marking conduit and equipment; access, pathways, and smoke ventilation; and the location of DC conductors in both residential and commercial buildings. Although the *Guideline* provides specific information that ensures compliance in these areas, there is little information about how the recommendations were developed.

In response to this information gap, I developed this background document, *Understanding the CAL FIRE Solar Photovoltaic Installation Guideline*, for the Solar America Board for Codes and Standards (Solar ABCs). In it, I explain how the CAL FIRE task force developed the *Guideline* and why task force members recommended that PV systems be designed and installed to accommodate firefighting operations.

In May 2010, the International Code Council (ICC) approved a revised version of the *Guideline* for inclusion in the 2012 version of the International Fire Code (IFC). This elevates the importance of the *Guideline* from a recommendation to a legally binding code, and makes a thorough grounding in the reasoning behind the *Guideline* even more important.

Without the information contained in this background document, local fire officials may be unwilling to consider alternative means and methods, choosing instead to rigidly implement the IFC. Rigid enforcement creates a process that lacks flexibility, and the complexities of the built environment require flexibility. CAL FIRE's intention in working with the PV industry was to facilitate the installation of PV systems while addressing the concerns of firefighters. A better understanding of the lengthy deliberations that went into the development of CAL FIRE's *Guideline* will encourage balanced and thoughtful enforcement.

In this document, I cover each section of the *Guideline*, indicating the corresponding section of the IFC in parentheses, repeating the language from the *Guideline* in italics, and including my clarifications in plain text.

"CAL FIRE's intention in working with the PV industry was to facilitate the installation of PV systems while addressing the concerns of firefighters."

Author Biography

Bill Brooks

Bill Brooks has worked with utility-interconnected PV systems since the late 1980s. He is a consultant to the PV industry on a variety of performance, troubleshooting, and training topics. Over the past 11 years, these training workshops have helped thousands of local inspectors and thousands of electricians and installers understand PV systems and how to properly install them.

His field troubleshooting skills have been valuable in determining where problems occur and to focus training on those issues of greatest need. Mr. Brooks has written several important technical manuals for the industry that are now widely used in California and beyond. His experience includes work on technical committees for the National Electrical Code, Article 690, and IEEE utility interconnection standards for PV systems. In 2008, the Solar Energy Industries Association appointed him to Code Making Panel 4 of the National Electrical Code.

Mr. Brooks holds bachelor and master of science degrees in mechanical engineering from North Carolina State University and is a registered professional engineer in both North Carolina and California.

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Solar America Board for Codes and Standards

The Solar America Board for Codes and Standards (Solar ABCs) provides an effective venue for all solar stakeholders. A collaboration of experts formally gathers and prioritizes input from groups such as policy makers, manufacturers, installers, and large- and small-scale consumers to make balanced recommendations to codes and standards organizations for existing and new solar technologies. The U.S. Department of Energy funds Solar ABCs as part of its commitment to facilitate widespread adoption of safe, reliable, and cost-effective solar technologies.

Solar America Board for Codes and Standards Web site:

www.solarabcs.org

Acknowledgements

This material is based upon work supported by the Department of Energy under Award Number DE-FC36-07GO17034.

Table of Contents

DISCLAIMER ii

EXECUTIVE SUMMARY iii

AUTHOR BIOGRAPHY iv

SOLAR AMERICA BOARD FOR CODES AND STANDARDS iv

ACKNOWLEDGEMENTS iv

BACKGROUND 1

GUIDELINE LANGUAGE—RECOMMENDATIONS FOR ENFORCEMENT 3

MARKING (IFC 605.11.1) 3

- Main Service Disconnect (IFC 605.11.1.3) 3
- Marking Content and Format (IFC 605.11.1.1 and 605.11.1.2) 4
- 1.2 Marking for DC Conduit, Raceways, Enclosures, Cable Assemblies, and Junction Boxes (IFC 605.11.1 and 605.11.1.4) 4
- Marking Content and Format (IFC 605.11.1.1 and 605.11.1.2) 5
- Inverters 5

ACCESS, PATHWAYS, AND SMOKE VENTILATION (IFC 605.11.3) 6

- Residential Systems—Single and two-unit residential dwellings (IFC 605.11.3.2) 8
  - (IFC 605.11.3) 8
  - (IFC 605.11.3.1) 8
  - (IFC 605.11.3.2.1) 9
  - (IFC 605.11.3.2.2 and (IFC 605.11.3.2.3) 10
  - Ventilation (IFC 605.11.3.2.4) 10
- Commercial Buildings and Residential Housing with three or more units (IFC 605.11.3.3) 11
- Access (IFC 605.11.3.3.1) 11
- Pathways (IFC 605.11.3.3.2) 12
- Ventilation (IFC 605.11.3.3.3) 12

LOCATION OF DC CONDUCTORS (IFC 605.11.2) 13

NON-HABITABLE BUILDINGS (IFC 605.11.4) 14

- Ground-Mounted Photovoltiac Arrays (IFC 605.11.4) 14

Appendix A: Information Intentionally Omitted from the Guidelines 15

Appendix B: New IFC and UFC Regulations Under Development 18

ACRONYMS 25

BACKGROUND

Photovoltaic (PV) systems present unique hazards for firefighters. In a building without a PV system, firefighters can disconnect the utility alternating current (AC) service to protect themselves from electric shock during fire suppression activities. When a PV system is present, however, the situation is not as straightforward.

When utility power is interrupted, the AC output of the PV system inverter instantly shuts down, and the power flowing to the AC wiring in the building or to local utility lines stops. When the AC power stops flowing, the direct current (DC) power from the PV system also stops flowing.

The issue is that although the DC current isn't flowing, the PV array's DC voltage remains, and the PV system rests in an open-circuit condition awaiting the return of the utility power. This open-circuit condition is hazardous to anyone coming in contact with the circuits, and firefighters accustomed to conventional AC power systems but unfamiliar with PV systems can be exposed to dangerous and potentially fatal risks. For more details about why the load side of a DC switch in a PV array typically remains energized even when the power is off, see Appendix A.

In August 2007, the California Department of Forestry and Fire Protection's (CAL FIRE's) Office of the State Fire Marshal began developing guidelines for the construction of PV systems in California to address these risks. It organized a task force of fire service and solar industry representatives, building officials, and codes and standards experts, which met during a period of more than six months. This effort culminated in the release of the *Solar Photovoltaic Installation Guideline* on April 22, 2008. The *Guideline* is available as a free download at http://osfm.fire.ca.gov/pdf/reports/solarphotovoltaicguideline.pdf.

One of the first decisions CAL FIRE made was to develop a guideline rather than a regulation. The task force agreed with this approach because a guideline provides the flexibility to accommodate changes in response to lessons learned by local jurisdictions. In addition, regulations require a rulemaking, which would delay implementation by local jurisdictions.

The purpose of the *Guideline* is to help firefighters identify PV systems, protect electrical wiring, and safely access roofs for vertical ventilation operations during fire suppression activities. The *Guideline* includes guidance about clearly marking conduit and equipment; access, pathways, and smoke ventilation; and the location of DC conductors in both residential and commercial buildings. Although the *Guideline* provides specific information that ensures compliance in these areas, there is little information about how the recommendations were developed.

In response to this information gap, I developed this background document, Understanding the *CAL FIRE Solar Photovoltaic Installation Guideline*, for the Solar America Board for Codes and Standards (Solar ABCs). In it, I explain how the CAL FIRE task force developed the *Guideline* and why task force members recommended that PV systems be designed and installed to accommodate firefighting operations. The process of developing the *Guideline* involved numerous discussions, after which the text was circulated to task force members for comment and correction. The information provided here represents my understanding of the issues as a member of this task force, and I hope it will be useful to stakeholders including fire prevention officers, plans reviewers, firefighters, building officials, PV system designers, PV system installers, and PV equipment manufacturers.

From Guideline To Code

In May 2010, the International Code Council (ICC) approved a revised version of the *Guideline* for inclusion in the 2012 version of the International Fire Code (IFC). This elevates the importance of the *Guideline* from a recommendation to a legally binding code, and makes a thorough grounding in the reasoning behind the *Guideline* even more important.

The revised wording of the IFC reminds local fire jurisdictions of their prerogative to provide alternative means and methods of compliance. In most cases, approving an alternative method of compliance requires an in-depth understanding of the original requirement. Although many PV installations easily comply with the IFC requirements, some installations require adaptations. Without the information contained in this background document, local fire officials may be unwilling to consider alternative means and methods, choosing instead to rigidly implement the IFC.

Rigid enforcement creates a process that lacks flexibility, and the complexities of the built environment require flexibility. CAL FIRE's intention in working with the PV industry was to facilitate the installation of PV systems while addressing the concerns of firefighters. A better understanding of the lengthy deliberations that went into the development of CAL FIRE's *Guideline* will encourage balanced and thoughtful enforcement.

There are two major fire codes used in the United States, the IFC published by the ICC and the Uniform Fire Code (UFC) published by the National Fire Protection Association (NFPA). The UFC is also known by its code designation, NFPA 1. Most U.S. jurisdictions use one of these two codes. The 2012 IFC includes provisions on PV installations in Section 605. NFPA is considering including provisions on PV installations in the 2012 UFC (see Appendix B). Both of these code changes include provisions very similar to those in the CAL FIRE *Guideline*, because both organizations used it as the template for their requirements.

The National Electrical Code (NEC®), which covers the fire safety requirements for electrical systems including PV systems, is also published by NFPA and can be referred to by its code designation of NFPA 70. The NEC is the basis for all electrical codes used in the United States.

"This elevates the importance of the *Guideline* from a recommendation to a legally binding code, and makes a thorough grounding in the reasoning behind the Guideline even more important."

GUIDELINE LANGUAGE – RECOMMENDATIONS FOR ENFORCEMENT

In the following sections, I cover each section of the *Guideline,* indicating the corresponding section of the IFC in parentheses, repeating the language from the *Guideline* in italics, and including my clarifications in plain text.

INTRODUCTION

The CAL FIRE *Guideline* begins with several pages of introductory information, including a history of the task force that developed the document, a short explanation of PV systems for stakeholders unfamiliar with the technology, a resource list for further study, and an explanation of what local governments must do to adopt the guidelines and enforce them as a local ordinance. The brief PV system background provides basic facts, including that PV systems only produce electricity during daylight hours, the typical locations of AC and DC disconnects, and that DC voltages can reach 600 volts. The introduction also describes other types of solar systems and notes that solar thermal systems for heating water or air may look similar to PV arrays, but do not present the electrical hazards of a PV system.

MARKING (IFC 605.11.1)

Marking is needed to provide emergency responders with appropriate warning and guidance with respect to isolating the solar electric system. This can facilitate identifying energized electrical lines that connect the solar modules to the inverter, as these should not be cut when venting for smoke removal.

Materials used for marking should be weather resistant. Use UL 969 as standard to weather rating (UL listing of markings is not required).

The section on marking covers the requirements for identifying PV circuits and the means for disconnecting them. The intent is to help ensure that firefighters are aware that a PV system is present and are not injured by PV-energized circuits.

The second paragraph related to weather resistance gives specific guidance on the requirement that circuits and equipment in outdoor locations be marked using weather resistant products. UL 969, "Marking and Labeling Systems," covers the resistance of labeling materials to UV radiation and moisture. It is common practice in the electrical industry to have placards custom-made by sign shops, using engraved plastic or metal materials. If the labels do not need to be customized, generic vinyl labels can be printed in volume. Vinyl labels should be specified as compliant with UL 969, but plastic and metal engraved labels do not require such a specification.

Main Service Disconnect (IFC 605.11.1.3)

For residential applications, the marking may be placed within the main service disconnect. If the main service disconnect is operable with the service panel closed, then the marking should be placed on the outside cover.

For commercial applications, the marking should be placed adjacent to the main service disconnect in a location clearly visible from the location where the lever is operated.

This section addresses the location of and specifications for identifying an electrical service that includes a PV system. Residential services often require opening a cover to access the main disconnect, and in those cases, the identification should be located inside the cover so that emergency personnel clearly see the labeling while operating the main service disconnect. If the main disconnect can be operated from outside the cover, the label should be mounted on or adjacent to the equipment.

The specifications for these labels indicate that adhesive-fastened labels are acceptable, although some jurisdictions require labels to be mechanically fastened. Mechanical fastening requirements often makes it difficult or impossible to mount the label on outdoor equipment, because putting fasteners on outdoor equipment may violate the equipment listing to safety standards. A mechanical fastening requirement will often require the label to be mounted next to the equipment rather than on the equipment.

Some roofs have both PV and solar thermal systems. Solar thermal panels have no electrical components and pose no risk of electric shock. An array diagram located at the service panel may be used to illustrate the locations of the solar electric and solar thermal systems.

Marking Content and Format (IFC 605.11.1.1 and 605.11.1.2)

- *MARKING CONTENT: CAUTION: SOLAR ELECTRIC SYSTEM*
- *RED BACKGROUND*
- *WHITE LETTERING*
- *MINIMUM 3/8" LETTER HEIGHT*
- *ALL CAPITAL LETTERS*
- *ARIAL OR SIMILAR FONT, NON-BOLD*
- *REFLECTIVE, WEATHER RESISTANT MATERIAL SUITABLE FOR THE ENVIRONMENT (durable adhesive materials meet this requirement)*

CAUTION: SOLAR ELECTRIC SYSTEM

1.2 Marking for DC Conduit, Raceways, Enclosures, Cable Assemblies, and Junction Boxes (IFC 605.11.1 and 605.11.1.4)

Marking is required on all interior and exterior DC conduit, raceways, enclosures, cable assemblies, and junction boxes to alert the fire service to avoid cutting them. Marking should be placed on all interior and exterior DC conduit, raceways, enclosures, and cable assemblies, every 10 feet, at turns and above and/or below penetrations and all DC combiner and junction boxes.

According to the *Guideline*, the DC side of the system requires specific visual identification of different kinds of solar panels (electric and thermal) and equipment such as inverters, combiner boxes, disconnects, and wiring systems. With a basic understanding of these major components, along with the labels covered in this section, it should be clear to firefighters and operations personnel that PV equipment is present and constitutes a hazard during daylight hours.

In commercial facilities, it is common practice to identify the contents of piping systems, including electrical conduit. Although there is no specific language exempting residential PV from identifying these circuits, it is less necessary, because non-metallic cables are more common in residential wiring. If a house has metal conduit installed, it is most likely either PV wiring or service entrance conductors, both of which firefighters should avoid. Simply said, commercial buildings have metal piping systems that require identification for various reasons. Metal conduit is less common in residential structures, and indicates a PV system.

In either case, firefighters should avoid touching the conduit. If a fire is present in the structure, these metal raceways may contain compromised conductors that could energize the conduit, shocking anyone who touches them. The labeling serves as an indicator that firefighters should avoid cutting the conduit and exercise caution when working near it.

The task force also discussed developing a complementary training program for fire service personnel. In this program, trainers cover aspects of the *Guideline* specifically and PV systems generally to help local fire departments develop standard operating procedures. This training program was introduced in November 2010 and will be available on the CAL FIRE website in 2011.

Marking Content and Format (IFC 605.11.1.1 and 605.11.1.2)

- *MARKING CONTENT: CAUTION SOLAR CIRCUIT (NEC® and IFC uses Warning: Photovoltaic Power Source")*
- *RED BACKGROUND*
- *WHITE LETTERING*
- *MINIMUM 3/8" LETTER HEIGHT*
- *ALL CAPITAL LETTERS*
- *ARIAL OR SIMILAR FONT, NON-BOLD*
- *REFLECTIVE, WEATHER RESISTANT MATERIAL (durable adhesive materials meet this requirement)*

The intent of this section is to standardize the information, size and color, and construction of the warning labels on wiring systems and junction boxes. Some raised concerns that the CAL FIRE's preference for red labels with white lettering does not meet OSHA sign standards. The California and IFC requirements avoid the term "sign," because these labels are not used for the same purposes as OSHA signs. The IFC proposal that passed in May 2010 included slight wording changes to make the IFC consistent with the NEC. The message in the IFC proposal reads, "Warning: Photovoltaic Power Source."

Inverters

The inverter is a device used to convert DC electricity from the solar system to AC electricity for use in the building's electrical system or the grid.

No specific markings are required by the California guidelines or the IFC requirements for the inverter, because the NEC already includes requirements for marking the PV power source disconnect, and that marking must be in the vicinity of the inverter.

ACCESS, PATHWAYS, AND SMOKE VENTILATION (IFC 605.11.3)

Section 2 of the *Guideline* addresses the access needs of fire departments that engage in vertical ventilation operations, which is a strategy for removing smoke from inside a burning structure. Although most fire departments engage in vertical ventilation operations, some are limiting this firefighting method depending on a structure's construction and the fire safety elements included in the building. For example, some types of roof construction may not be fire resistant enough to justify the risk of sending firefighters to the roof, and other buildings may have enough automatic vents that roof ventilation operations are unnecessary.

If manual roof ventilation is unnecessary, firefighters may require only access and egress to and from the roof to fight rooftop fires. Roof construction also plays a role in the decision process, because non-combustible roof decking such as concrete and metal may make ventilation operations impractical. Although a few fire departments may engage in vertical ventilation operations on metal and concrete decked roofs, they are the exceptions rather than the rule. In general, exceptions to access pathways and smoke ventilation must be approved by the fire jurisdiction, so the specifics of construction and operations are handled through the design review process.

Access and spacing requirements should be observed in order to:

- *Ensure access to the roof*
- *Provide pathways to specific areas of the roof*
- *Provide for smoke ventilation opportunities area*
- *Provide emergency egress from the roof*

Meeting the requirements of this section will limit the locations available for mounting PV modules, which is likely to make it a focus of concern for both solar professionals and firefighters. Understanding the requirements in this section is critical to properly enforcing the rules and enabling the flexibility to make adjustments to the rules when alternative means and methods can address the issues.

This list of bullets outlines why firefighters need clear spaces to work safely on a roof. The first bullet refers to firefighters' need to gain access to the roof with ladders or similar means. When they have achieved access to the roof, they must be able to get to the specific areas that require inspection or ventilation, as noted in the second bullet. As the third bullet points out, another reason to provide space on rooftops is so that the roof can be ventilated to help remove smoke from inside a burning structure. Lastly, firefighters require clear pathways to get off a roof quickly, as bullet four suggests. Typically, firefighters prefer to identify multiple pathways for egress so that if the fire cuts off one egress pathway, an alternative is available. The alternative pathways may not need to be as wide or structurally sound as the primary access and egress pathways.

Local jurisdictions may create exceptions to this requirement where access, pathway, or ventilation requirements are reduced due to:

- *Proximity and type of adjacent exposures*
- *Alternative access opportunities (as from adjoining roofs)*
- *Ground level access to the roof area in question*
- *Adequate ventilation opportunities beneath solar array (as with significantly elevated or widely-spaced arrays)*
- *Adequate ventilation opportunities afforded by module set back from other rooftop equipment (shading or structural constraints may leave significant areas open for ventilation near HVAC equipment, for example)*
- *Automatic ventilation device*
- *New technology, methods, or other innovations that ensure adequate fire department access, pathways, and ventilation opportunities*

The *Guideline* encourages local jurisdictions to exercise flexibility in the enforcement of these requirements in response to a variety of site-specific issues. The first three bullets describe circumstances that may allow fire departments to relax the setback options on a roof. PV arrays are often only mounted on one roof face (closest to south) so that other roof faces may be fully open for roof access and venting.

The next two bullets describe examples of PV array placement that allow for venting. In the first, the array is tilted above the roof pitch sufficiently to allow firefighters access to the roof below. In the second, gaps in the array intended to avoid shading from rooftop equipment such as HVAC units or the shrouds used to hide this equipment allow access for firefighters.

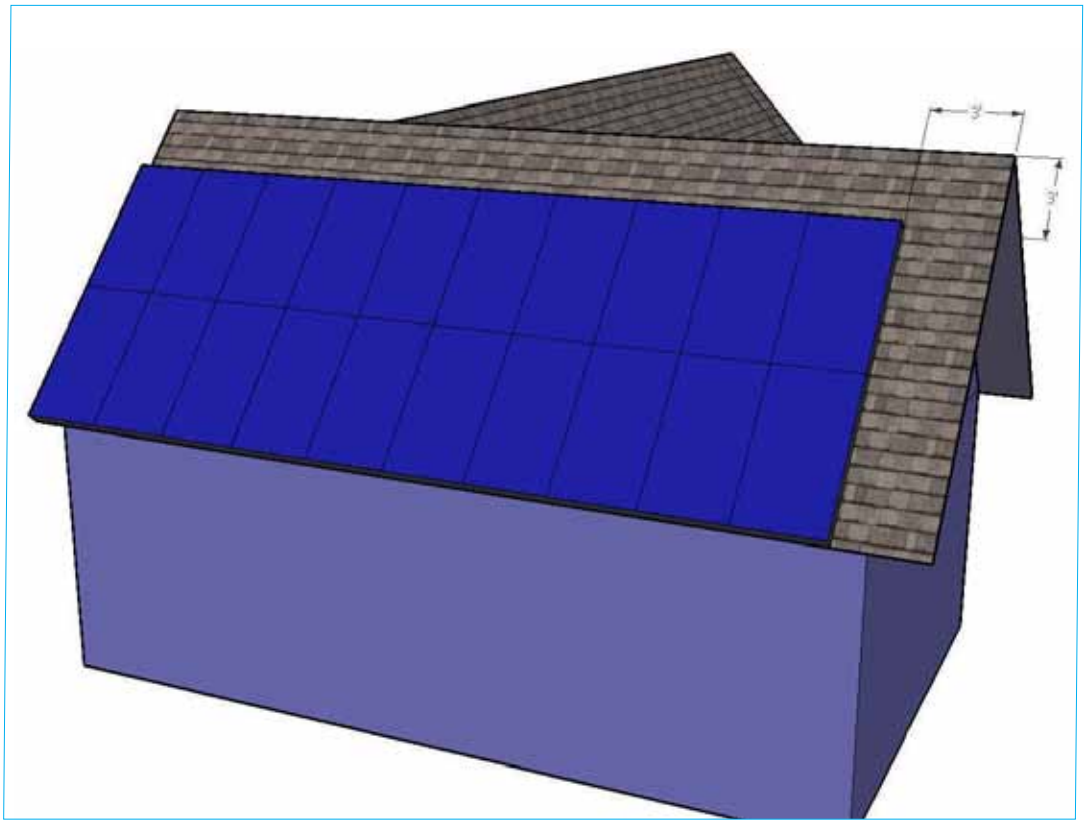
The last two bullets describe currently available ventilation options and potential new innovations that may allow easy removal of PV modules for roof ventilation access. In addition, some arrays include solar thermal panels that may be removable for roof ventilation access. The task force included these measures so that jurisdictional authorities would consider optional means and methods to meet the intent of adequate roof access and ventilation opportunities.

Designation of ridge, hip, and valley does not apply to roofs with 2-in-12 or less pitch. All roof dimensions measured to centerlines.

Roof access points should be defined as an area that does not place ladders over openings (i.e., windows or doors) and are located at strong points of building construction and in locations where it does not conflict with overhead obstructions such as tree limbs, wires, or signs.

An important distinction is made in this section with respect to residential low-slope (flat) roof construction. The guideline clarifies that requirements related to ridges, hips, or valleys do not apply to flat roofs. Simply stated, only a three-foot perimeter space would be required for flat residential roofs.

Examples of Compliant PV Array Layout for Different Rooftops

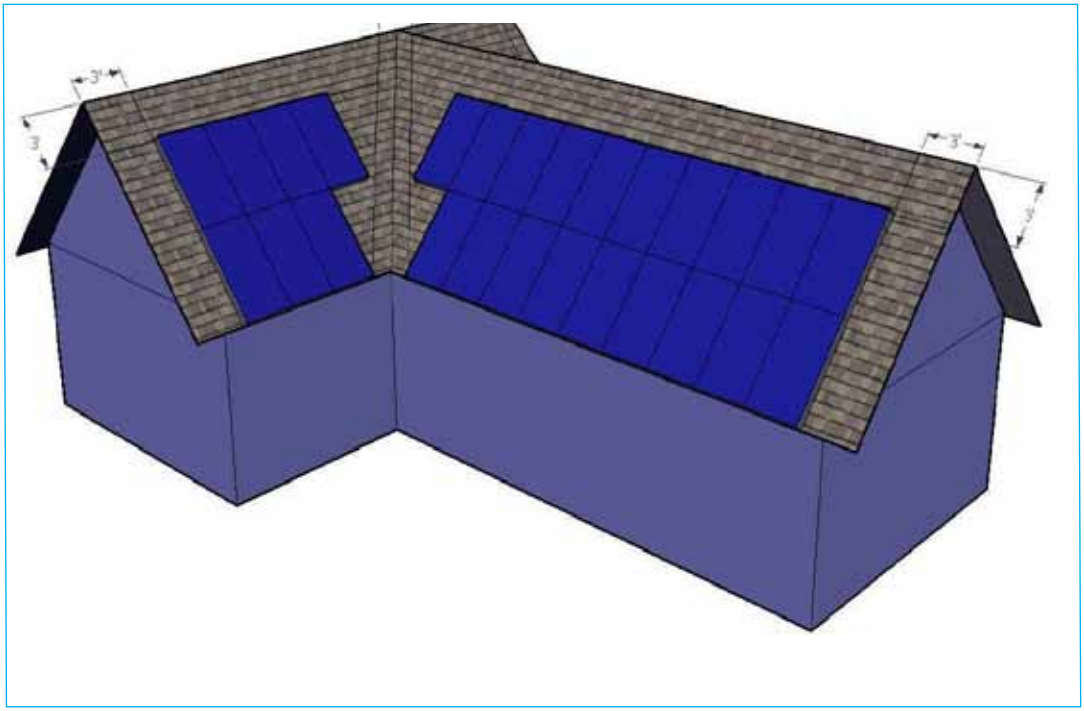


Plan review is required if a system is to be installed that will occupy more than 50% of the roof area of a residential building.

Examples of these requirements appear at the end of this guideline.

This statement suggests a relative PV system size that might trigger a plan review. Some jurisdictions have mistakenly interpreted this statement to mean that this applies to the area of the roof plane where the system will be installed. The intent of the task force was to minimize administrative review if the PV system will occupy no more than 50% of the total roof area. In order to achieve more than 50% of a residential sloped roof typically means mounting PV modules on multiple roof faces. This complicates the installation and increases the need for the fire department to review the plans to make sure that the PV system will still allow adequate access and ventilating opportunities. Systems that occupy less than 50% of a residence's roof area are generally simpler, and are likely to offer sufficient access and ventilation opportunities. This recommendation is not specifically mentioned in the IFC language.

Example 2: Cross Gable with Valley



(IFC 605.11.3 and 605.11.3.1)

The three-foot access and ventilation requirements in 2.1.1. and 2.1.2 are among the most controversial items in the *Guideline* for both the solar industry and firefighters. The "three-foot rule" was the subject of lengthy deliberation and debate. Initially, the fire service requested four-foot setbacks and the solar industry preferred a two-foot setback. The three-foot setback was a compromise that could reasonably address the access needs of firefighters while allowing more room for larger solar arrays.

The wind loading on rooftops limits the roof area available for PV installations on many homes in high wind regions. The American Society of Civil Engineers (ASCE) publishes a standard ASCE-7, entitled "Building Loads on Structures," which U.S. building codes reference. This standard includes tables for wind pressures based upon location, wind exposure, and location on the roof. The outer three-foot corners of a residential sloped roof structure has wind pressures that are double those three feet from the edge of the

roof. PV modules are generally tested to withstand 30 pounds per square foot (PSF), and areas of the country with design wind speeds greater than 110 mph could experience wind pressures in excess of 30 PSF at roof corners. By staying away from the upper three-foot corners of a sloped roof, PV modules can be mounted safely and still provide firefighters the access they need to get to the ridge of the roof for ventilation operations.

This section does not discuss access to other roof faces, because each roof face must stand on its own. The reason for this distinction is that, during roof operations, adjacent roof faces may not be available for access or ventilation holes. One reason for a roof face to be unavailable for ventilation operations is that a strong wind on a roof face can make ventilation holes counterproductive.

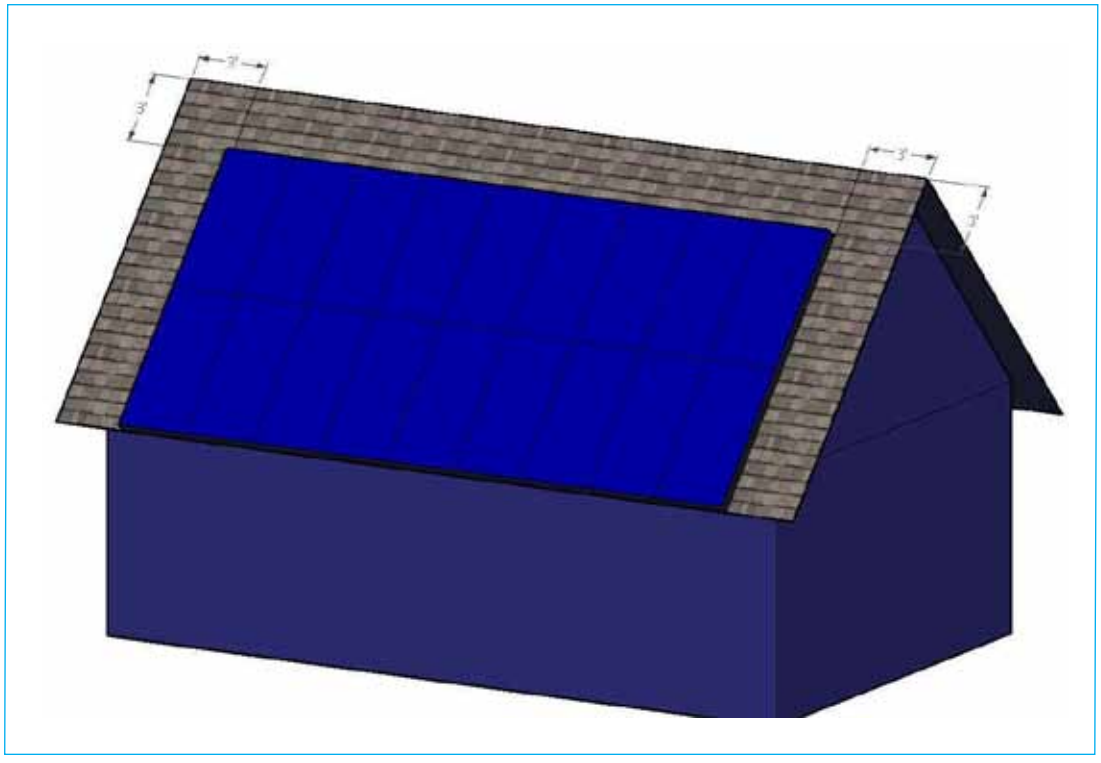
(IFC 605.11.3.2.1)

a. *Residential Buildings with hip roof layouts. Modules should be located in a manner that provides one (1) three-foot (3') wide clear access pathway from the eave to the ridge on each roof slope where modules are located. The access pathway should be located at a structurally strong location on the building (such as a bearing wall).*

Hip roofs often have a relatively small center ridge section with side ridges (hips) that provide access to the corners of the building. These hips are not as structurally strong as single ridge gable ends. Only a single three-foot pathway is required, because it is necessary that at least one three-foot pathway be available on any roof slope with a PV array. This pathway is intended to be the primary access and egress for the roof. However, should this pathway be blocked or compromised during a fire, firefighters can make an emergency escape from the closest unaffected hip or slope to get to safety.

Although it is possible that a firefighter could walk on the opposing slope, there is a three-foot pathway on the PV slope in the event that a firefighter has to rapidly cross the hip slope to access a ladder against the PV slope at the corner. This would limit the total distance and time the firefighter would need to traverse the roof to get to a ladder.

Example 3: Full Gable

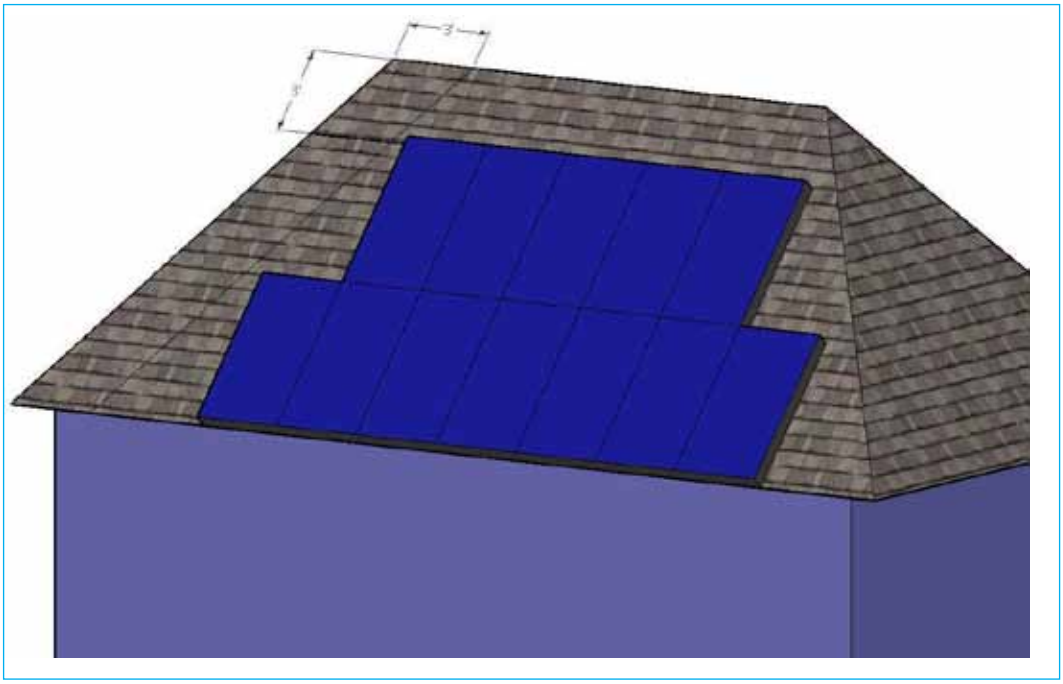


(IFC 605.11.3.2.2)

b. *Residential Buildings with a single ridge. Modules should be located in a manner that provides two (2) three-foot (3') wide access pathways from the eave to the ridge on each roof slope where modules are located.*

Single ridge roofs, such as full gable construction, have structurally strong framed end walls that provide good access and egress for the firefighter to either end of the structure. Single ridge residences require two three-foot wide pathways to provide alternate means of access and egress for firefighters. As a related issue, these ridges can be long relative to the size of the structure so it is likely that one pathway is not accessible in a fire.

Example 4: Full Hip Roof



(IFC 605.11.3.2.3)

c. *Hips and Valleys: Modules should be located no closer than one and one half (1.5) feet to a hip or a valley if modules are to be placed on both sides of a hip or valley. If the modules are to be located on only one side of a hip or valley that is of equal length then the modules may be placed directly adjacent to the hip or valley.*

Roof types covered in (a) and (b) are common simple roof constructions. However, many roofs include a combination of ridges, valleys, and hips. Hips and valleys are treated differently from gable construction, because the hips and valleys often do not have structural walls under them. This makes hips and valleys less substantial than other access and egress options and therefore a lower priority during firefighting operations. However, hips and valleys may become a path for emergency egress should a fire prevent the firefighter from accessing the preferred structural access and egress location.

Ventilation (IFC 605.11.3.2.4)

Modules should be located no higher than three feet (3) below the ridge.

The purpose of the three-foot ridge setback for residential sloped roofs is twofold. First, it provides for access along the ridge for firefighters to move along the structurally stronger ridge. A minimum of 18 inches on either side of the ridge is generally used for a pathway so that firefighters can work their way along a roof ridge and step aside to allow another firefighter to pass without forcing either person too far away from the stronger ridge section.

Second, the three-foot space is intended to provide sufficient room for firefighters to cut a standard 16-square-foot vent hole two feet wide and eight feet long. This two-foot by eight-foot hole is in lieu of the more common four-foot by four-foot hole that is used for rafters or trusses on 24-inch centers. The four-foot by four-foot hole is cut with a rafter or truss at the centerline of the 4' cut. This method only requires a single hinging action with 24-inch on center rafter or truss construction. A two-foot by eight-foot hole requires additional cuts and at least two louvered sections. This method of venting is commonly referred to as "dicing." It allows for a scalable hole by just lengthening the top and bottom cuts and "dicing" in between, completing new louvered sections. Another method is to make a four-foot by four-foot cut straddling the ridge of the roof. This last method may compromise an alternate escape route, but may be quicker than other methods and is used by some fire departments.

The ridge setback for photovoltaic modules assumes that they are energized and cannot be moved. Solar thermal panels, which are not energized and are removable for ventilation access, can be installed within 18 inches of the ridge, keeping the access pathway clear. In the future, as products are developed that automatically de-energize PV modules (see Appendix B), these special modules could also be removed safely, allowing systems to be installed as close as 18 inches from the ridge.

Some solar arrays are flashed into the roof. These flashing details should be allowed to extend into the three-foot setback areas, because this part of the array can be moved or removed during ventilation operations.

Commercial Buildings and Residential Housing with Three or More Units (IFC 605.11.3.3)

This classification covers all habitable structures that are not one- and two- family residences. The intent is to follow building code classifications, because there are many distinctions in building codes among single and two family residences and other building types.

Exception: If a local fire department determines that the roof configuration is similar to residential (such as in the case of townhouses, condominiums, or single family attached buildings), the local fire department may make a determination to apply the residential access and ventilation requirements.

Examples of these requirements appear at the end of this guideline.

Access (IFC 605.11.3.3.1)

There should be a minimum six (6) foot wide clear perimeter around the edges of the roof.

Exception: If either axis of the building is 250 feet or less, there should be a minimum four feet (4') wide clear perimeter around the edges of the roof.

The access areas around the perimeter of a building are larger for commercial buildings than for single- and two-family residences for a variety of reasons. One is that firefighters must carry more gear and equipment for some roof operations on larger commercial buildings. Another is that more firefighters are generally dispatched for larger buildings, and they require extra space to maneuver around one another, particularly in the vicinity of access ladders. The exception acknowledges that smaller roofs will need fewer personnel and therefore less clearance.

For proper operation of a PV system, the perimeter area is often unusable because of shading and wind loads. Shading from parapet walls on flat roofs can be significant. Generally, a setback distance of twice the parapet wall height is necessary to prevent excessive shading by the wall. A three-foot parapet wall will require a six-foot setback to prevent shading. Higher wind speeds along the perimeter of a roof also make the edge of the roof unusable in many regions of the United States. In addition, the further the PV array is from the edge of a roof, the less likely construction workers will be exposed to the hazard of falling from the edge of the roof.

Pathways (IFC 605.11.3.3.2)

Pathways should be established in the design of the solar installation. Pathways should meet the following requirements:

- *Should be over structural members*
- *Centerline axis pathways should be provided in both axes of the roof. Centerline axis pathways should run on structural members or over the next closest structural member nearest to the centerlines of the roof*
- *Should be straight line not less than 4 feet clear to skylights and/or ventilation hatches*
- *Should be straight line not less than 4 feet clear to roof standpipes*
- *Should provide not less than 4 feet clear around roof access hatch with at least one not less than 4 feet clear pathway to parapet or roof edge*

The intent of pathway recommendations for commercial roofs is to place the walkways in locations firefighters would most likely use during rooftop operations if no solar array were present. Generally, firefighters will find a major structural member and follow that member across the roof when it is necessary to leave the roof edge. While following structural members is not always possible because the member may not be obvious, these provisions were intended to make those preferred paths available. The IFC language only requires that the pathway be on parts of the roof capable of supporting the weight of a firefighter. Skylights, ventilation hatches, and standpipes are key ventilation and access locations that must have clear pathways from the edge of the roof. These pathways ensure that the firefighter is free to move around the perimeter and to access the ventilation location closest to the fire. Roof hatches may also be used for ventilation or building access, depending on the source and type of the fire.

Ventilation (IFC 605.11.3.3.3)

a. *Arrays should be no greater than 150 by 150 feet in distance in either axis*
b. *Ventilation options between array sections should be either:*
    1. *A pathway 8 feet or greater in width*
    2. *4 feet or greater in width pathway and bordering on existing roof skylights or ventilation hatches*
    3. *4 feet or greater in width pathway and bordering 4' x 8' "venting cutouts" every 20 feet on alternating sides of the pathway*

The reason the size of the array is discussed in the ventilation section is to allow for ventilation opportunities no further apart than 150 feet. This assumes that a large building that could accommodate multiple 150-foot by 150-foot array blocks is fairly open so that smoke can travel to an available venting location. The more compartmentalized the space below the roof is, the more firefighters will prefer multiple venting opportunities. Some buildings make ample use of skylights, which can greatly facilitate venting opportunities during a fire. Of course, these skylights and ventilation hatches need to be accessible. Maintenance personnel also need access to these locations to repair and maintain skylights and hatches. The third option is an attempt to allow for a four-foot wide walkway and yet take up less room than an eight-foot pathway that would also be used for ventilation purposes. The alternating areas for ventilation are to provide venting options on either side of a structural member in case that structural member is over a partition wall. While this option helps meet the needs of firefighters, alternating sides of the pathway would not be a preferred method for the effective layout of a PV array, so it is less likely to be used by PV system designers.

LOCATION OF DC CONDUCTORS (IFC 605.11.2)

Conduit, wiring systems, and raceways for photovoltaic circuits should be located as close as possible to the ridge or hip or valley and from the hip or valley as directly as possible to an outside wall to reduce trip hazards and maximize ventilation opportunities.

Conduit runs between sub arrays and to DC combiner boxes should use design guidelines that minimize the total amount of conduit on the roof by taking the shortest path from the array to the DC combiner box. The DC combiner boxes are to be located such that conduit runs are minimized in the pathways between arrays.

To limit the hazard of cutting live conduit in venting operations, DC wiring should be run in metallic conduit or raceways when located within enclosed spaces in a building and should be run, to the maximum extent possible, along the bottom of load-bearing members.

Since the development of these guidelines in early 2008, several additions have been made to the 2011 NEC to address firefighters' concerns in the routing of conductors. In most residential rooftop systems, conduit is run exterior to the structure. Conduit runs generally proceed from the edge of the array closest to the location of the inverter, and the shortest possible path is taken to get to the inverter. Ridges, hips, and valleys may be used to run conduit as recommended in this section.

If conduit is run inside the structure, it is usually in attic spaces, so the last paragraph recommends running conduit along the bottom of load-bearing members to the extent possible. Firefighters are not going to cut through load-bearing members, making them safer locations to route conduit. However, other options may be as good or better in reducing the likelihood of conduit damage from firefighter operations. A series of requirements adopted by the 2011 NEC more specifically clarifies the acceptable options. I include these sections here for reference:

690.4 (E)

(E) Circuit Routing. Photovoltaic source and PV output conductors, in and out of conduit, and inside of a building or structure, shall be routed along building structural members such as beams, rafters, trusses, and columns where the location of those structural members can be determined by observation. Where circuits are imbedded in built-up, laminate, or membrane roofing materials in roof areas not covered by PV modules and associated equipment, the location of circuits shall be clearly marked.

690.31(E) (New)

Wiring methods shall not be installed within 25 cm (10 in.) of the roof decking or sheathing except where directly below the roof surface covered by PV modules and associated equipment. Circuits shall be run vertically from the roof penetration point to supports a minimum of 25 cm (10 in.) below the roof decking.

Informational Note: The 25 cm (10 in.) requirement is to prevent accidental damage from saws used by firefighters for roof ventilation during a structure fire.

Where flexible metal conduit (FMC) or metal clad cable (MC) smaller than metric designator 21 (trade size 3/4) containing PV power circuit conductors is installed across ceilings or floor joists, the raceway or cable shall be protected by substantial guard strips that are at least as high as the raceway or cable. Where run exposed, other than within 1.8 m (6 ft) of their connection to equipment, these wiring methods shall closely follow the building surface or be protected from physical damage by an approved means.

NON-HABITABLE BUILDINGS (IFC 605.11.4)

This guideline does not apply to non-habitable structures. Examples of non-habitable structures include, but are not limited to, parking shade structures, solar trellises, etc.

Ground-Mounted Photovoltiac Arrays (Ifc 605.11.4)

Setback requirements do not apply to ground-mounted, free standing photovoltaic arrays. A clear brush area of 10' is required for ground mounted photovoltaic arrays.

Clear brush areas are required around ground-mounted systems to reduce the safety hazard of fuel from brush that could start a fire that would propagate beyond the limits of the PV array.

Appendix A: Information Intentionally Omitted From the *Guidelines*

PV Array DC Disconnects to Protect Firefighters

During the past decade, CAL FIRE has been tasked with developing installation guidelines for PV systems. One of the most common of their draft requirements relates to disconnects on rooftops. The history of service disconnects for fire operations is to protect firefighters from energized conductors. One of the first activities of a team of firefighters is to control the energy utilities to a structure (typically utility electrical and gas). The addition of a PV system on the roof of the structure poses a unique challenge to firefighting operations. It seems logical that adding disconnects at the source of power—the PV array—will effectively eliminate that source from the building, but that is not the case.

The task force intentionally omitted a requirement to install rooftop DC disconnects at PV module arrays, because they may not de-energize the circuits associated with the switch and can give firefighters a false sense of safety. If the circuits are not de-energized, and a firefighter believes that it is safe to move a raceway associated with that switch, it is possible that the firefighter could be severely shocked or electrocuted. For this reason, the CAL FIRE draft *Solar Photovoltaic Installation Guideline*, dated April 2008, does not include any language related to rooftop PV array switches.

The *Guideline* also does not explain why the requirement was omitted. This has caused various jurisdictional authorities and fire enforcement representatives to believe that the omission was accidental and to introduce an additional requirement. This was evidenced in the wording of the initial IFC proposal, which has subsequently been withdrawn:

> 611.6 Power disconnects. A power disconnect shall be located within 3 feet of the photovoltaic array to provide for de-energizing the DC circuit(s) from the array to the inverter. The disconnect shall be labeled with reflective lettering.

The Problem

Turning off a rooftop DC disconnect in a PV system does not de-energize the conductors on either side of the switch. Because of this concern, the NEC requires a warning label on these types of switches. This label must read substantially

> WARNING. ELECTRIC SHOCK HAZARD.
> DO NOT TOUCH TERMINALS. TERMINALS ON BOTH THE LINE AND LOAD SIDES MAY BE ENERGIZED IN THE OPEN POSITION.

This warning is primarily for electricians performing work on the equipment as a reminder that normal electrical conventions do not apply to this equipment. Normally, a safety disconnect has energized conductors to the line side of the switch, but the load side of the switch is always de-energized when the switch is off. This is because no other source of power typically exists on the load side of a switch. With PV systems, this assumption is wrong in almost every case, thus the requirement for a warning label.

To understand why the load side of a DC switch in a PV array is typically energized, we must look at how PV systems work. The majority of rooftop PV systems are connected directly to an electrical converter, called an inverter, that takes the DC power from the PV array, converts it to AC power compatible with the utility system, and then supplies that power to existing distribution equipment in the building. On the AC side, if the utility power is shut down for any reason, the AC output of the PV system inverter instantly shuts down to prevent a hazardous condition on the AC wiring in the building or on local utility lines. If the AC side is shut down, the DC power from the array instantly stops

flowing. The DC current also stops, but the DC voltage remains—the PV array rests in an open-circuit condition awaiting the return of utility power.

Although power isn't flowing, this open-circuit condition is still hazardous to anyone coming in contact with the circuits. That is the fundamental reason firefighters want to shut the voltage off in that circuit. In small residential rooftop PV systems, all the circuits from the roof are typically run into a single raceway, so it seems logical to install a DC disconnect to de-energize this conduit. Although it is possible to interrupt the circuit from the roof to the inverter, the voltage on the load side of the switch is coming from the inverter—specifically from the input capacitors for the array.

All PV inverters without battery systems include large input capacitors, which store "half-wave" power from the PV array so that the inverter can produce AC power, which fluctuates at 60 cycles per second, and keep the power from the PV array at a constant DC voltage. These capacitors have "bleed resistors" to gradually deplete the charge to zero volts when the voltage is removed from them. This bleed-down process takes five to 15 minutes and is intended to make the equipment safe for servicing. This five- to 15-minute time period is fine for maintenance work, but far too long for fire operations. A firefighter, thinking this circuit is de-energized, could easily be shocked by these large capacitors. While the shock on a small PV system is unlikely to be fatal, the involuntary muscle reaction to the shock could easily cause the firefighter to lose balance and fall off the roof, resulting in serious injury or death.

On larger commercial PV systems, there can be dozens of electrical distribution boxes electrically combined at a large inverter at ground level. Although the 2011 NEC will require DC disconnects for each rooftop combiner box, turning off these disconnects may not de-energize any of the circuits or conduit. For the same reason small systems are not de-energized, large inverters have massive capacitor banks that are capable of causing a severe burn or even electrocution. These capacitor banks have bleed resistors, but the large inverters require the same five- to 15-minute waiting period as small inverters and the capacitors will only start to discharge after all the rooftop disconnects are switched off.

IMPACT ON FIRE OPERATIONS

A utility AC service disconnect provides protection that does not exist with DC disconnects in a PV system. Electricians and firefighters who are accustomed to the conventional AC frame of reference and are unfamiliar with PV systems can be exposed to dangerous and potentially fatal risks. This is why the code requirement for warning labels on all PV disconnects is so important. For example, if 15 disconnects exist on a roof—one at the location of each subarray combiner box—and only one of the 15 is left on, the entire array wiring system can be fully energized and lethal. In the smoke and confusion of a fire, it is likely that one or more of the disconnects will not be identifiable or accessible because the fire is blocking access. Firefighters in daytime operations must always assume that the equipment is energized and potentially dangerous.

The 2011 NEC has established several new requirements for PV systems in the routing of wiring systems, marking, arc-fault detection systems, and disconnects for combiner boxes. These improvements in safety will not solve all current hazards, but they will reduce the danger to firefighters and maintenance personnel. Basic education on the hazards of PV systems is the key to safe and effective firefighting operations. Although disconnects on combiner boxes will help isolate circuits during overhaul operations, they should not be the focus during fire suppression operations.

From a fire safety point of view, requiring disconnects is not adequate protection for firefighters. Staying clear of PV modules and the associated raceways is the only way to guarantee the safety of firefighters.

TECHNOLOGY ADVANCES THAT MAKE PV SYSTEMS SAFER

Although the use of DC disconnects in current PV system designs does not provide protection for firefighters, several new technologies show promise in addressing some or all of firefighters' major electrical concerns with PV installations. These new technologies place communications and control features directly into each module, allowing individual modules to shut down instantly. These module-level electronics, sometimes called module-level control or smart modules, could easily communicate with the inverter and shut each module off in response to a utility outage or a shutdown of the main AC service. By controlling the voltage at the module level, the electrical hazards of the PV array are eliminated, and firefighters can concentrate on their main goal of fire suppression rather than energy control for the PV system. One of the challenges of developing new safety measures is how to make them easily identifiable to firefighters. Without a clear indication that safety measures have been employed, the firefighter must assume that typical PV system hazards exist.

Appendix B: New IFC and UFC Regulations Under Development

There are two primary fire codes used in the United States today. The first is the International Fire Code (IFC) published every three years by the International Code Council (ICC). The second is the Uniform Fire Code (UFC) published by the National Fire Protection Association (NFPA). The UFC is often referred to by the code designation of NFPA 1.

Both draft documents for the 2012 code cycle include language related to solar photovoltaic (PV) system regulation that is based upon the CAL FIRE *Guideline*. One significant difference between the California document and these fire regulations is the emphasis of the language. The California document is a recommended practice—not a requirement—and words like "must" and "shall" are not used. The IFC and UFC are standards written as requirements, however, and the word "shall" is used in place of "should."

IFC F30 Code Compared to the CAL FIRE *Guideline*

Comparing the IFC F30 code and the CAL FIRE *Guideline* side by side, it becomes clear that the IFC regulation is largely based upon the California document, but with the increased emphasis of code requirements. Several important differences do exist, however. Rather than cover all the similarities here, I will only address the significant differences. The reasoning behind issues such as access, pathways, and ventilation has not changed, but the language has. To summarize the differences:

- All instances of "should" were changed to "shall" to make the statements code requirements rather than recommendations.
- The recommendation to have access pathways on top of structural members of a building is amended to require only that the roof be capable of handling the live load of a firefighter.
- The exception for fire departments to amend the three-foot rule for residences is prominently featured at the beginning of the section on access, pathways, and smoke ventilation.
- The NEC is referenced for additional requirements for marking, labeling, and routing of wiring methods.
- Ladder access is specified so that the locations are not in front of windows or doors and the access points do not have obstructions such as tree limbs, wires, or signs.
- Residential structures shall be designed so that each array is no greater than 150 feet by 150 feet in either axis.
- The word "Caution" is replaced with "Warning" on signage.

The following is the new language for the 2012 IFC:

> **605.11 Solar Photovoltaic Power Systems.** Solar photovoltaic power systems shall be installed in accordance with this code, the International Building Code and NFPA 70.
>
> > **Exception:** Detached Group U non-habitable structures such as parking shade structures, carports, solar trellises, and similar type structures are not subject to the requirements of this section.
>
> **605.11.1 Marking. Marking** is required on all interior and exterior DC conduit, enclosures, raceways, cable assemblies, junction boxes, combiner boxes, and disconnects.

605.11.1.1 Materials. The materials used for marking shall be reflective, weather resistant and suitable for the environment. Marking as required in sections 605.11.1.2 through 605.11.1.4 shall have all letters capitalized with a minimum height of 3/8 inch (9.5 mm) white on red background.

605.11.1.2 Marking content. The marking shall contain the words WARNING: PHOTOVOLTAIC POWER SOURCE.

605.11.1.3 Main service disconnect. The marking shall be placed adjacent to the main service disconnect in a location clearly visible from the location where the disconnect is operated.

605.11.1.4 Location of marking. Marking shall be placed on all interior and exterior DC conduit, raceways, enclosures and cable assemblies every 10 feet (3048 mm) within 1 foot (305 mm) of all turns or bends and within 1 foot (305 mm) above and below all penetrations of roof/ceiling assemblies and all walls and /or barriers.

605.11.2 Locations of DC conductors. Conduit, wiring systems, and raceways for photovoltaic circuits shall be located as close as possible to the ridge or hip or valley and from the hip or valley as directly as possible to an outside wall to reduce trip hazards and maximize ventilation opportunities. Conduit runs between subarrays and to DC combiner boxes shall be installed in a manner that minimizes total amount of conduit on the roof by taking the shortest path from the array to the DC combiner box. The DC combiner boxes shall be located such that conduit runs are minimized in the pathways between arrays. DC wiring shall be installed in metallic conduit or raceways when located within enclosed spaces in a building. Conduit shall run along the bottom of load bearing members.

605.11.3 Access and pathways. Roof access, pathways, and spacing requirements shall be provided in order to ensure access to the roof; provide pathways to specific areas of the roof; provide for smoke ventilation operations; and to provide emergency egress from the roof.

Exceptions:

1. Requirements relating to ridge, hip, and valleys do not apply to roofs slopes of two units vertical in twelve units horizontal (2:12) or less.
2. Residential structures shall be designed so that each array is no greater than 150 feet (45 720 mm) by 150 feet (45 720 mm) in either axis.
3. The fire chief may allow panels/modules to be located up to the ridge when an alternative ventilation method acceptable to the fire chief has been provided or where the fire chief has determined vertical ventilation techniques will not be employed.

605.11.3.1 Roof access points. Roof access points shall be defined as an area that does not place ground ladders over openings such as windows or doors, and are located at strong points of building construction in locations where the access point does not conflict with overhead obstructions such as tree limbs, wires, or signs.

605.11.3.2 Residential systems for one- and two-family residential dwellings. Access shall be provided in accordance with Sections 605.11.3.2.1 through 605.11.3.2.4.

605.11.3.2.1 Residential buildings with hip roof layouts. Panels/modules shall be located in a manner that provides a 3 foot (914 mm) wide clear access pathway from the eave to the ridge on each roof slope where panels/modules are located. The access pathway shall be located at a structurally strong location on the building capable of supporting the live load of firefighters accessing the roof.

605.11.3.2.2 Residential buildings with a single ridge. Panels/modules shall be located in a manner that provides two 3 foot (914 mm) wide access pathways from the eave to the ridge on each roof slope where panels/modules are located.

605.11.3.2.3 Hips and valleys. Panels/modules shall be located no closer than 18 inches (457 mm) to a hip or a valley if panels/modules are to be placed on both sides of a hip or valley. If the panels are to be located on only one side of a hip or valley that is of equal length then the panels shall be permitted to be placed directly adjacent to the hip or valley.

605.11.3.2.4 Smoke ventilation. Panels/modules shall be located no higher than 3 feet (914 mm) below the ridge in order to allow for fire department smoke ventilation operations.

605.11.3.3 All other occupancies. Access shall be provided in accordance with Sections 605.11.3.3.1 through 605.11.3.3.3.

Exception: Where it is determined by the *fire code official* that the roof configuration is similar to a one- or two-family dwelling, the *fire code official* may *approve* the residential access and ventilation requirements provided in 605.11.3.2.1 through 605.11.3.2.4.

605.11.3.3.1 Access. There shall be a minimum 6 foot (1829 mm) wide clear perimeter around the edges of the roof.

Exception: If either axis of the building is 250 feet (76 200 mm) or less, there shall be a minimum 4 foot (1290 mm) wide clear perimeter around the edges of the roof.

605.11.3.3.2 Pathways. The solar installation shall be designed to provide designated pathways. The pathways shall meet the following requirements:

1. The pathway shall be over areas capable of supporting the live load of firefighters accessing the roof
2. The centerline axis pathways shall be provided in both axes of the roof. Centerline axis pathways shall run where the roof structure is capable of supporting the live load of firefighters accessing the roof.
3. Shall be straight line not less than 4 feet (1290 mm) clear to skylights and/or ventilation hatches
4. Shall be straight line not less than 4 feet (1290 mm) clear to roof standpipes
5. Shall provide not less than 4 feet (1290 mm) clear around roof access hatch with at least one not less than 4 feet (1290 mm) clear pathway to parapet or roof edge

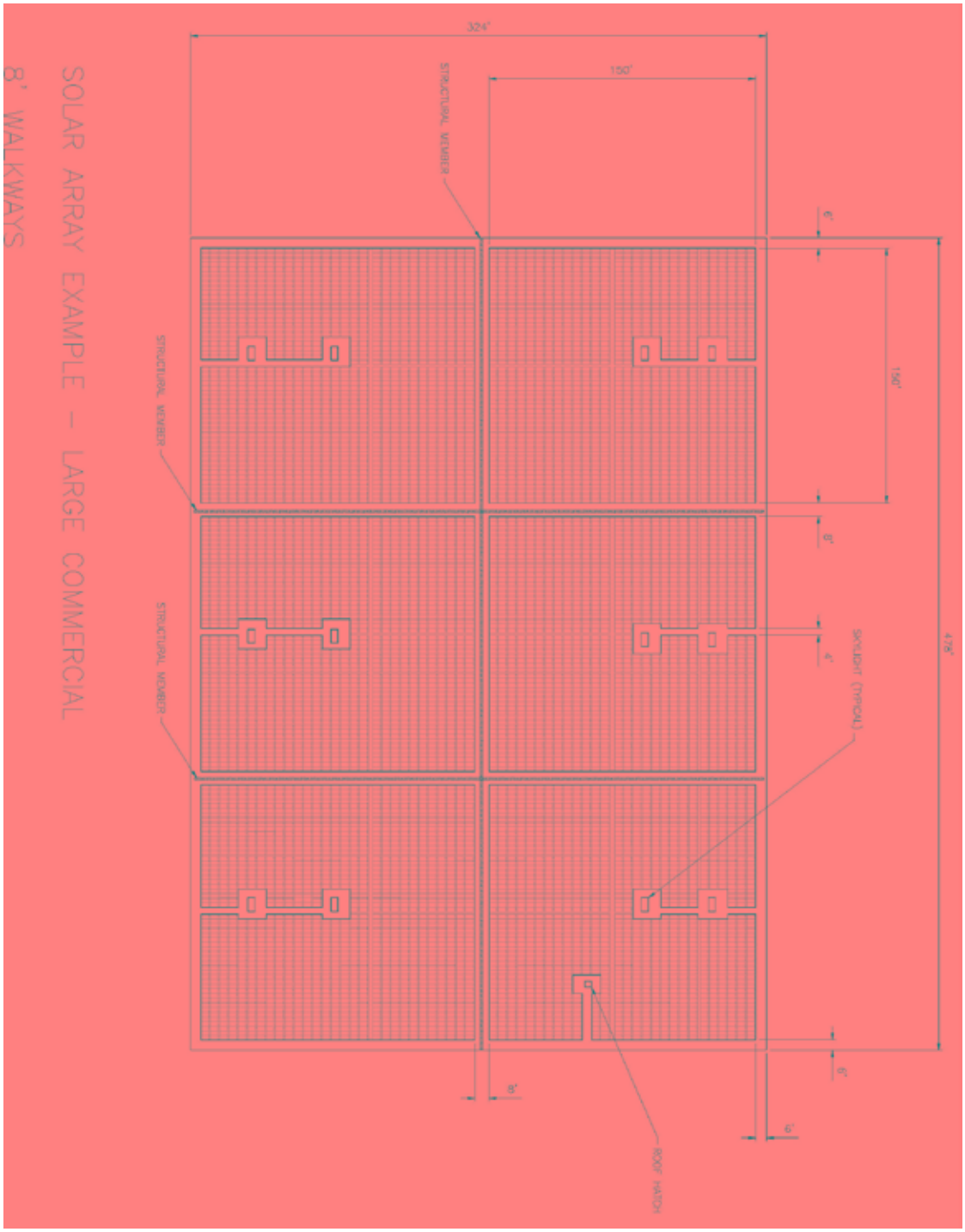
605.11.3.3.3 Smoke ventilation. The solar installation shall be designed to meet the following requirements:

1. Arrays shall be no greater than 150 feet (45 720 mm) by 150 feet (45 720 mm) in distance in either axis in order to create opportunities for smoke ventilation operations.
2. Smoke ventilation options between array sections shall be one of the following:
   2.1. A pathway 8 feet (2438 mm) or greater in width
   2.2. A 4 feet (1290 mm) or greater in width pathway and bordering roof skylights or smoke and heat vents

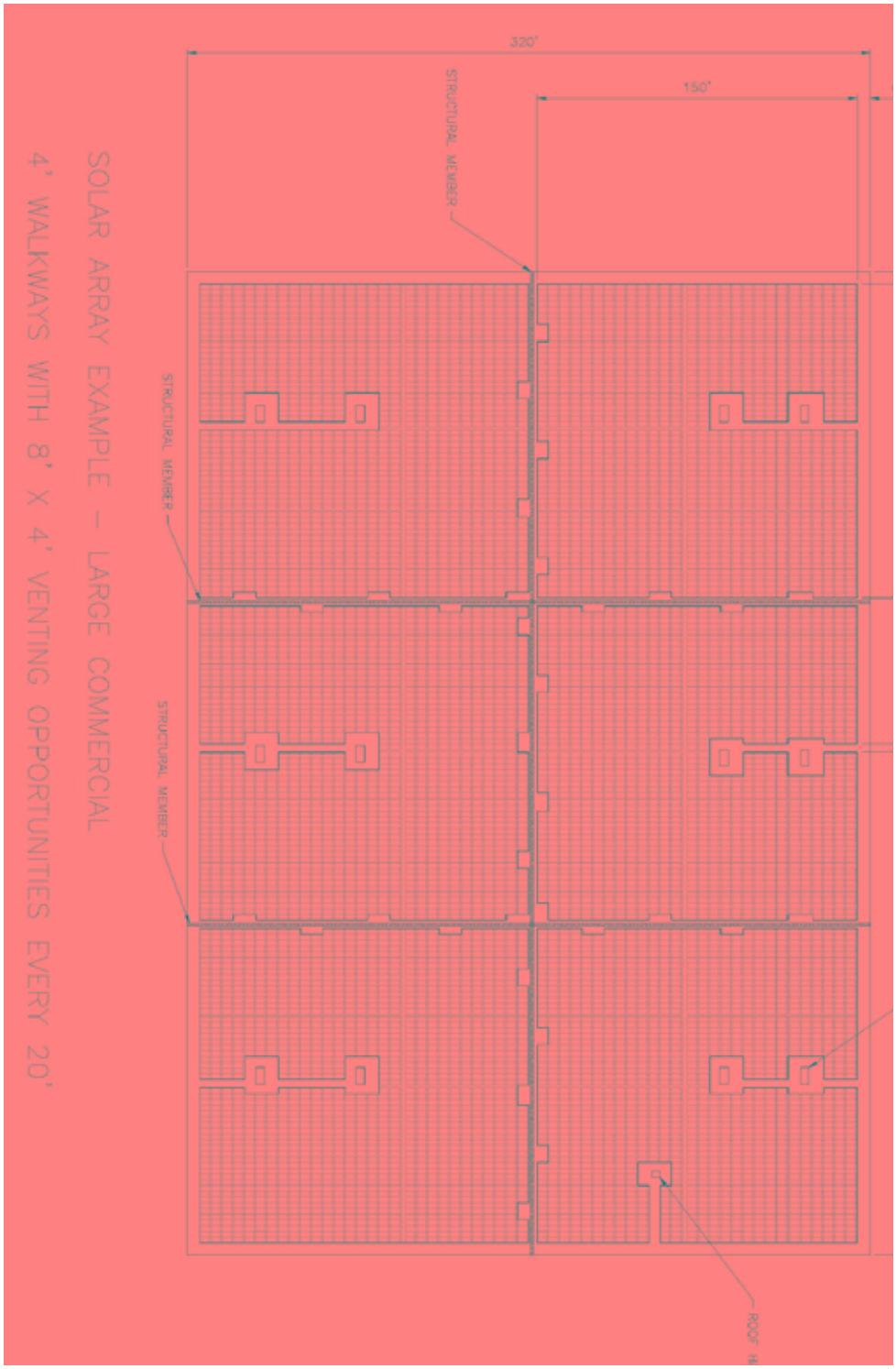
2.3. A 4 feet (1290 mm) or greater in width pathway and bordering 4 foot (1290 mm) x 8 foot (2438 mm) “venting cutouts” every 20 feet 6096 mm) on alternating sides of the pathway

605.11.4 Ground mounted photovoltaic arrays. Ground mounted photovoltaic arrays shall comply with Sections 605.11 through 605.11.2 and this section. Setback requirements do not apply to ground-mounted, free standing photovoltaic arrays. A clear brush area of 10 feet (3048 mm) is required for ground mounted photovoltaic arrays.

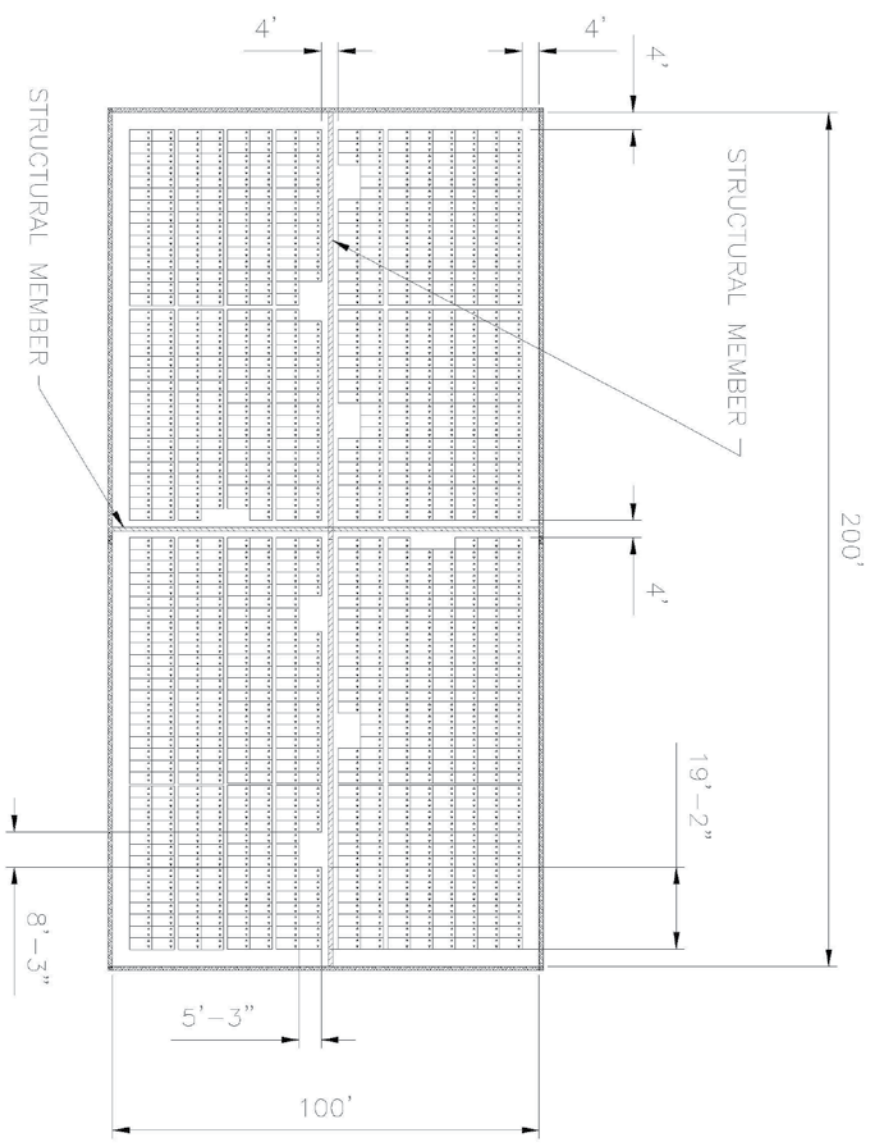
Example 5 – Large Commercial 8-Foot Walkways



Example 6 – Large Commercial 4-Foot Walkways



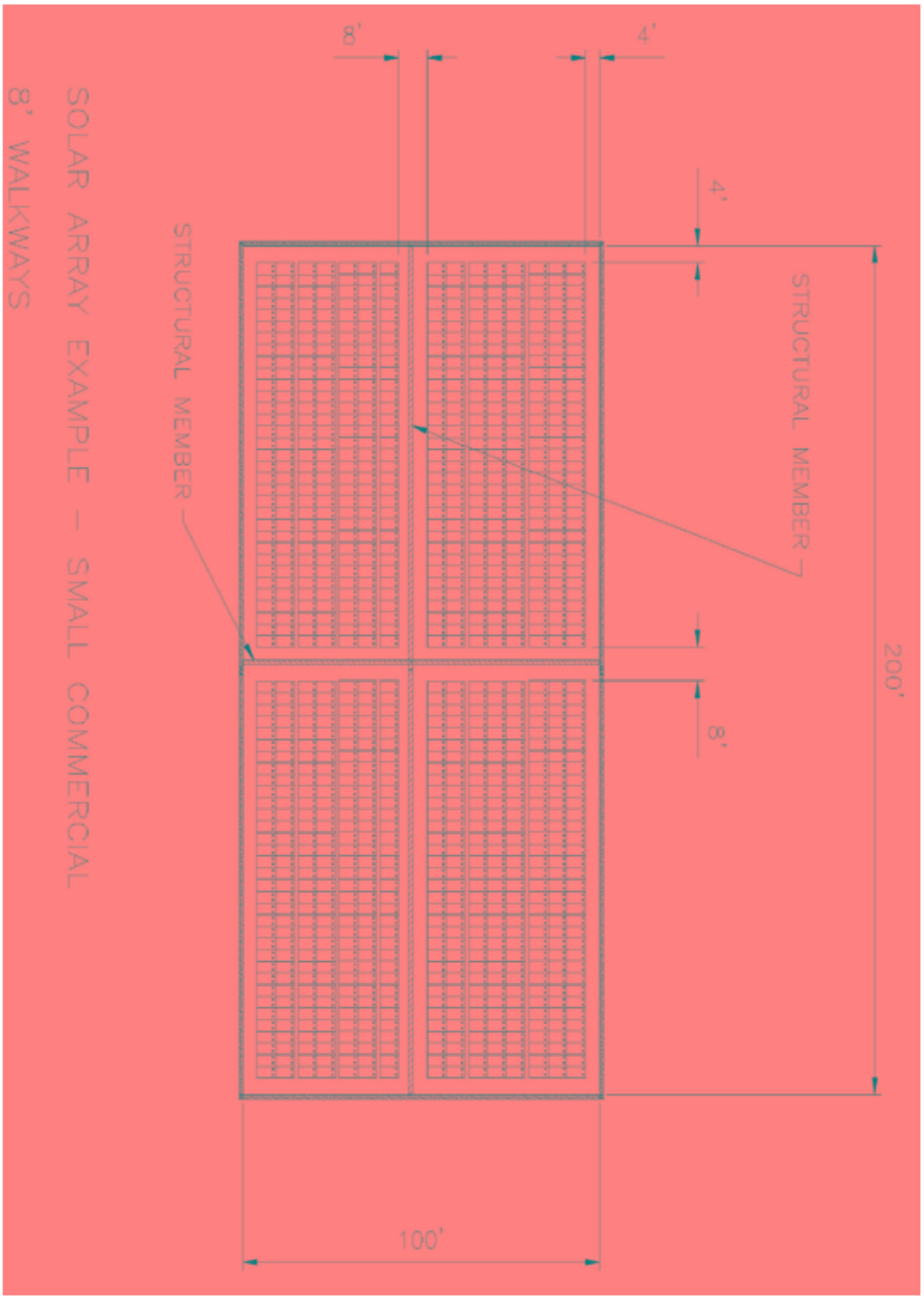
Example 7 – Small Commercial 4-Foot Walkways



SOLAR ARRAY EXAMPLE – SMALL COMMERCIAL

4' WALKWAYS WITH 8' X 4' VENTING OPPORTUNITIES EVERY 20 ' ALONG WALKWAY

Example 8 – Small Commercial 8-Foot Walkways



ACRONYMS

AC	alternating current
ASCE	American Society of Civil Engineers
CAL FIRE	California Department of Forestry and Fire Protection
DC	direct current
ICC	International Code Council
IFC	International Fire Code
NEC	National Electrical Code
NFPA	National Fire Protection Association
PSF	pounds per square foot
PV	photovoltaic
Solar ABCs	Solar America Board for Codes and Standards
UFC	Uniform Fire Code

Solar America Board for Codes and Standards

www.solarabcs.org

A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering

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January 2012

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Executive Summary

Net energy metering (NEM) is a state-level policy that permits a utility customer to generate electricity on site to offset the customer's load and deliver any excess electricity to the utility for an equal amount of electricity from the utility at other times. Forty-three states, the District of Columbia, and Puerto Rico have instituted NEM in some form to permit self-generation, typically at the urging of customers seeking to use solar, wind, and other renewable energy facilities. These NEM policies vary from state to state, particularly regarding how large an individual installation can be and how much NEM will be allowed in the aggregate. Restrictions on NEM are almost always driven by utility concerns that lower utility bills for NEM customers will lead to higher utility bills for customers who do not have NEM.

The intent of this report is to provide a consistent methodology to analyze the potential rate impacts of NEM. With reliable estimates of rate impacts, regulators can make informed decisions regarding modification of NEM rules, and our intent here is to provide a methodology for more reliable estimates. In this report, we review and synthesize three studies performed for major utilities in Arizona, California, and Texas during the past decade. All three were on a scale far beyond the scope of this report, but the broad categories of costs and benefits identified in the studies are not specific to a given utility.

Based on this review, we provide a generalized approach for any state or utility to analyze the potential rate impact of NEM in its area. The analysis and results of such studies are utility-specific, but the methodology should not be. If benefits exceed costs, then regulators may want to consider lifting restrictions on NEM and crediting NEM customers for the net benefits they provide. If costs exceed benefits, then other ratepayers are subsidizing NEM customers, and regulators must decide whether externalities such as reduced pollution, job creation, and resource diversity justify the subsidy.

Costs of NEM are often argued to be the utility's lost revenue and any associated administrative costs. Every kilowatt-hour (kWh) generated by an NEM customer means one less kWh sold by the utility at retail rates. The retail rate in question depends on the type of customer. Most residential and small commercial customers have a bundled rate that covers both their utility's fixed and variable costs, while large commercial customers typically have an "energy" charge based on kWh for variable costs and a "demand" charge based on the customer's peak usage, measured in kW, for fixed costs.

Typically, an NEM solar facility has minimal impact on the demand component of the demand-metered customer's bill. Even if the customer would have experienced peak demand coincident with sunshine without a solar array, and a solar array significantly lowered demand at that time, demand near that peak level after sunset or when the system is not operating will be unchanged. Thus, typically, demand-metered customers with an NEM solar facility primarily offset energy charges, which are much lower than the bundled rates for residential and small commercial customers. As the energy charge is based on variable costs that the utility no longer has to incur, the impact of NEM for these customers should be negligible. At present, roughly two-thirds of the installed capacity of all NEM solar facilities is located on commercial customer property, with much of that sized over 100 kW and likely to be offsetting the energy charges of demand-metered customers.

The other aspect of NEM costs is the utility's administrative expense. Most utilities use proprietary billing software that is costly to adapt for NEM. Therefore, in the short term many utilities use hand billing for NEM customers to avoid incurring a large cost for a

relatively small group of customers. However, over the medium to long term, changes to a utility's billing software to support evolving energy use patterns—dynamic rates, advanced metering, plug-in electric vehicles, etc.—will occur in the ordinary course of business. Logically, updating billing software to handle NEM program participants can occur as part of this longer-term evolution. Accordingly, we believe that the anticipated long-term administrative costs of a NEM program should be used in any rate impact analysis, on the reasonable presumption that billing of NEM customers will be automated.

On the benefits side of the rate impact calculation, the three studies we reviewed indicate that NEM allows utilities to save fuel expenses, avoid line losses, and realize at least some capacity benefit, while also suggesting various secondary benefits. An important component to the benefit calculation is determining what generation will be offset. Utility variable rates are based on average operating costs, and more than two-thirds of utility generation is from high capital cost/low operating cost coal, nuclear, and hydropower facilities. NEM solar facilities generally do not offset these baseload generators. Rather, they offset the lower capital cost/higher operating cost natural gas-fired facilities that operate during business hours and other periods of above-average demand to supplement baseload generation.

No matter which type of generation is offset, line loss savings are an important benefit of NEM. For every kWh generated by a utility-scale generator, five to ten percent of the electricity will be lost on the way to customers in the form of transmission and distribution losses. In contrast, NEM generation occurs at the customer's site, with almost no line loss. Neighbors typically use excess generation from a NEM facility, with negligible line losses. The demand on the distribution circuit serving the NEM customer drops by the full amount of the facility's generation at any given moment. Any line losses are utility- and time-specific, but for many utilities, higher losses occur during hot, sunny conditions. To calculate line loss savings associated with NEM solar facilities requires a reasonable estimate of average daytime line losses for that utility.

The most contentious element of the benefits calculation relates to capacity benefits. To the extent that NEM facilities allow a utility to delay or avoid construction of the next generator, transmission line, substation, or distribution line, there are clearly associated savings enjoyed by the utility and its customers. The studies we reviewed differed in their treatment of capacity benefits. We conclude that capacity benefits are real and incremental, with aggregate distributed solar generation far more stable and predictable than the obviously intermittent nature of individual solar facilities. We also include information about the potential for combining solar energy with demand response or energy storage programs to assure capacity benefits. While solar energy facilities are typically available during high demand periods, utility planners are hesitant to attribute capacity values to them because of the perception that they are not as reliable as traditional resources. Firming the output of solar energy generation with demand response or energy storage will allow utility planners to confidently rely on solar energy, particularly as new smart grid capabilities come online that allow grid operators to balance supply and demand at local levels in real time.

Author Biographies

Jason B. Keyes focuses on regulatory matters related to interconnection of distributed generation to the U.S. electric grid. On behalf of the Interstate Renewable Energy Council, he has participated in interconnection and net metering rulemakings at the utility commissions of fifteen states. As a partner at Keyes & Fox, LLP, he also represents private clients with all regulatory aspects of renewable energy project development. Prior to his legal career, Mr. Keyes managed government contracts and business development for eight years at JX Crystals Inc., a pioneer in the field of high-concentration solar energy systems. In the early 1990s, he helped develop the integrated resource plan and the demand forecast at Washington State's largest utility. Mr. Keyes received his juris doctor from the Seattle University School of Law, a master of arts in economics from the University of Washington, and a bachelor of arts from Dartmouth College. Mr. Keyes is a member of the Washington State Bar Association.

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Solar America Board for Codes and Standards

The Solar America Board for Codes and Standards (Solar ABCs) is a collaborative effort among experts to formally gather and prioritize input from the broad spectrum of solar photovoltaic stakeholders including policy makers, manufacturers, installers, and consumers resulting in coordinated recommendations to codes and standards making bodies for existing and new solar technologies. The U.S. Department of Energy funds the Solar ABCs as part of its commitment to facilitate widespread adoption of safe, reliable, and cost-effective solar technologies.

For more information, visit Solar ABC's website:
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ACKNOWLEDGEMENTS

The authors gratefully acknowledge the comments of the following reviewers: Galen Barbose, Lawrence Berkeley National Laboratory; Michael Coddington, National Renewable Energy Laboratory; Jennifer DeCesaro, U.S. Department of Energy; and Sarah Wright, Utah Clean Energy.

This material is based upon work supported by the U.S. Department of Energy under Award Number DE-FC36-07GO17034.

Table of Contents

DISCLAIMER ii

EXECUTIVE SUMMARY iii

AUTHOR BIOGRAPHIES v

SOLAR AMERICA BOARD FOR CODES AND STANDARDS v

ACKNOWLEDGEMENTS v

INTRODUCTION 1

PRESENT STATUS OF NET ENERGY METERING 2

- System Size Limitations 2
- Program Size Limitations 3
- Rollover of Excess Generation 4
- Standby Charges 4

RELEVANT STUDIES FOR EVALUATING NET ENERGY METERING RATE IMPACT 5

- Studies Valuing the Benefits of Solar Resources 5
- California's Cost Benefit Methodology for Distributed Energy Resources 9
- Quantifying the Capacity Value of Solar 15

BEST PRACTICES IN VALUING NET ENERGY METERING 16

CONCLUSION 19

RECOMMENDATIONS 20

REFERENCES 22

APPENDIX A 24

ACRONYMS 25

INTRODUCTION

Net energy metering (NEM) is critical to supporting customer investment in renewable distributed generation (DG). Although there are various policy options related to NEM, the basic structure allows a utility customer to generate electricity on site to offset the customer's load and deliver any excess electricity to the utility for an equal amount of electricity from the utility at other times. To facilitate the expansion of opportunities for customers to invest in DG, 43 states, the District of Columbia, and Puerto Rico have implemented NEM programs. Increasing interest in NEM programs has come at a particularly important juncture in the development of the solar industry as module prices declined markedly in 2009-2010. This decline in prices resulted in increased consumer interest in solar energy despite the economic climate. However, while many NEM programs in this two-year period broadened in scope, the quality of programs continued to vary widely between the states.

NEM programs have met with resistance, notably from utilities concerned that a robust NEM program in their service territory would result in significant rate impacts for nonparticipating customers and—in the case of an investor owned utility (IOU)—a loss of profit. Unfortunately, a detailed analysis of potential NEM rate impacts has only recently begun, so potential rate impacts are not well understood and there continues to be disagreement about the appropriate inputs for such analysis.

Despite this disagreement, efforts have moved forward, particularly in Arizona, California, and Texas, to more rigorously quantify the rate impacts of NEM programs. Together, these efforts facilitate the development of a consensus view of the most important considerations in the valuation of renewable energy resources, particularly distributed solar energy systems.

To assist state policy makers, utilities, utility regulators, renewables advocates, and other stakeholders in their efforts to evaluate the potential rate impacts of NEM in their states, we suggest a methodology based on standard NEM provisions in states with the highest levels of program participation. Because solar facilities make up the majority of net-metered facilities participating in state NEM programs, we focus on the impact of net-metered solar facilities. We analyze the methodology for determining rate impacts, and do not undertake a review of any particular state renewable energy program. In addition, we consider only the impact of net-metered solar facilities on non-participating customers' rates, not economic impacts, environmental impacts, or impacts on participating customers investing in DG resources.

The "Present Status of Net Energy Metering" section provides a background discussion focusing on the key NEM program variables that can impact rates. The "Relevant Studies for Evaluating Net Energy Metering Rate Impacts" section discusses the costs and benefits of NEM that should be considered in a rate impact analysis. The "Best Practices in Valuing Net Energy Metering" section reviews California's efforts to assess the rate impacts of NEM, which constitute the most thorough analysis to date. Finally, we present conclusions and recommendations. We cite references within the text by title or author, and include full citations in the "References" section at the end of the report.

PRESENT STATUS OF NET ENERGY METERING

NEM as a policy choice for supporting customer investment in renewable energy resources is thriving. According to the Database for State Incentives for Renewables & Efficiency *(http://www.dsireusa.org)*, 43 states, the District of Columbia, and Puerto Rico have adopted an NEM policy, as shown in Figure 1. Many states have adopted a policy that applies only to IOUs. However, some statewide policies also apply to municipal and cooperative utilities. Program rules vary widely among states on such crucial issues as overall NEM program size, facility size, allowance of third party ownership, and the ability to roll over excess generation from one month to the next.

Details on state NEM policies are thoroughly documented in an annual publication by the Network for New Energy Choices (NNEC) entitled Freeing the Grid: Best Practices in State Net Metering Policies and Interconnection Procedures (Network for New Energy Choices, 2011). The document provides side-by-side comparison of state policies in 11 areas related to facility size, program size, eligibility, metering, treatment of excess generation, allowance of third party ownership, and protection from standby charges and other fees that nonparticipating customers do not face. Within those policy areas, NNEC awards a sliding scale of points based on the policy choices each state has made with the most points going to states with policies that accommodate more distributed generation.

For purposes of reviewing rate impacts of NEM programs, system size limitations, program size limitations, rollover of excess generation, and standby charges are discussed here. Policy choices in these areas directly affect rate impacts. These restrictions are often undertaken in an effort to address concerns about rate impacts on non-participating customers, with the intent of mitigating the perceived rate impacts of a NEM program. And yet, expansive NEM policies are an important element in state efforts to promote customer-sited renewable generation. (Itron, 2010; Doris, McLaren, Healey, & Hockett, 2009; Paidipati, Frantzis, Sawyer, & Kurrasch, 2008)

System Size Limitations

Figure 1 shows that eligible system size ranges from 20 kilowatts (kW) in Wisconsin—the size of a very large residential system—to two megawatts (MW) or more in 14 states.

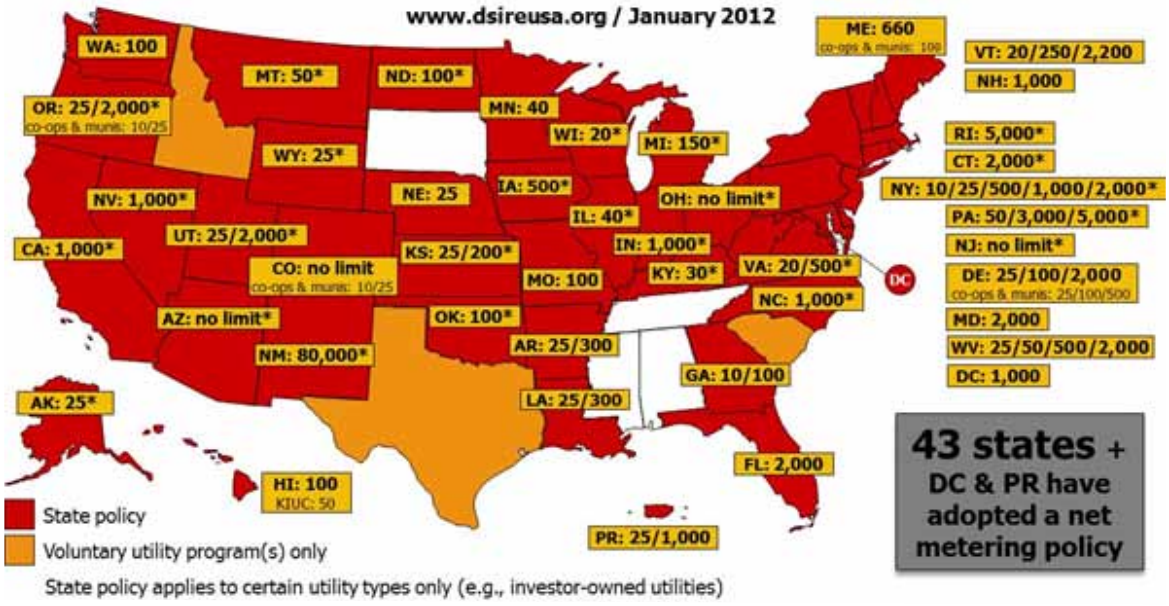

Figure 1. State net energy metering (January 2012, http://www.dsireusa.org). Numbers indicate residential/ commercial individual system capacity limits.

As Table 1 shows, the top ten states for customer-sited solar energy share the attribute of allowing NEM facilities of at least one MW, with the exception of Hawaii, which has unique characteristics.

TABLE 1
Top 10 States by Installed Capacity and Their NEM System Size Cap

2010 Rank by State	2010 Market Share	Cumulative MWDC	NEM System Size Cap
1. California	48 %	1,022	1,000 kW
2. New Jersey	12 %	260	no limit
3. Colorado	5 %	117	no limit
4. Arizona	5 %	105	no limit
5. Nevada	5 %	102	1,000 kW
6. Florida	3 %	73	2,000 kW
7. New York	3 %	56	2,000 kW
8.Pennsylvania	3 %	55	5,000 kW
9. Hawaii	2 %	45	100 kW
10. New Mexico	2 %	43	80,000 kW
All Other States	12 %	261	

*Source: Sherwood, L., **U.S. Solar Market Trends 2010**, Interstate Renewable Energy Council, June 2011. (Total of 2,139 MW_{DC})*

Program Size Limitations

Limitations on program size and the size of eligible systems often go hand in hand. These policies appeal to those who believe that NEM programs are a subsidy, but this position is widely debated. A December 2009 report by the National Renewable Energy Laboratory reviewed how states have considered the rate impacts issue, with no example of a state finding that subsidization exists (Doris, Busche, & Hockett, p. 15). The report notes that North Carolina and Maryland looked into the issue and decided not to attempt studies because the experience in other states "had not shown a negative rate impact." The report notes that in New York, an attempt at quantification was underway, but "the impacts have not been large enough to measure under the current data collection scheme." Having surveyed states on the issue, the report concludes that "[t]he states that have increased the net metering system size cap generally cited the limited impacts of net metering on ratepayers in other states."

These policy choices also hinder the development of renewable energy markets in two ways. First, program capacity caps signal to potential new energy developers that their efforts will ultimately be thwarted, not by a lack of customer interest, but by regulatory restrictions. At the same time, a cap on DG system size to less than one MW precludes development of economical systems above the size cap, and those larger systems have been an important driving force in market growth during the past few years. In the end, both policy choices signal to developers that their investments in building solar businesses are best made elsewhere.

Rollover of Excess Generation

At the heart of any NEM program is the treatment of generation in excess of a customer's needs. When implemented properly, NEM has nearly the same impact on a participating customer's utility bill as would occur if the customer-generator used a bank of batteries to store energy until the customer's demand exceeded his or her generation (batteries have modest losses, so NEM has a slightly greater utility bill impact). At its most basic, NEM allows a customer's meter to run backwards when the customer produces more power than the customer can use. (Note that most mechanical meters can actually run backwards, but for newer digital meters, "running backwards" is figurative.) States that do not allow this basic aspect of NEM simply do not "net meter" in the widely accepted understanding of the concept.

Once treatment of instantaneous excess generation is addressed, policy makers must consider the treatment of generation at the end of a particular billing period as they develop program rules. The most expansive net metering policy is to allow for indefinite rollover of net excess generation from billing period to billing period until it is used by the customer-generator. This policy choice provides the greatest flexibility in allowing customers to design a renewable energy system to meet their individualized needs, given the variations in output from a system over the course of the year and a customer's yearly consumption pattern. For many homeowners seeking to meet their entire annual load, solar energy generation in the sunny summer months exceeds their summer loads, with the excess offsetting loads in the winter.

Perpetual rollover of excess generation also avoids possible federal regulatory issues related to wholesale sales and addresses concerns that NEM might produce incentives for customers to oversize their systems. As well, the Internal Revenue Service has indicated in at least one private letter ruling that payment for excess generation is taxable income.

Stakeholders with concerns over the rate impacts of NEM often attempt to limit possible rate impacts by requiring the customer-generator to donate net excess generation at the end of a calendar year or some other twelve month period to the utility or to accept payment for the net excess generation at the utility's average avoided cost. Both of these program choices undervalue the net excess generation a customer provides to a utility by providing no value or valuing the on-site, customer-owned renewable energy generation at the cost of fossil fuel generation. NEM programs almost always have a requirement that systems be sized to meet no more than the customer's expected consumption, so substantially oversized systems are not built. Treatment of annual excess generation is an issue for the odd year when generation was higher than expected or consumption was lower than expected. Perpetual rollover of excess generation avoids the administrative burden of an annual reconciliation and gives the customer an assurance of credit for all energy delivered to the utility.

Standby Charges

There have been many instances of utilities proposing special tariffs for customer-generators structured as standby charges or other fees to compensate the utility for possible services that the utility provides. A utility's regulator—the state public utilities commission for IOUs, the city council for many municipal utilities, and other boards for various co-ops and public utility commissions—must approve such tariffs. From

another angle, some utilities have argued that any requirement that standby charges or fees may not be imposed is an unwarranted subsidy by nonparticipating ratepayers. Unfortunately, this argument does not account for the fact that standby charges were generally developed as a rate option for much larger cogeneration or combined heat and power facilities that supply energy on a steady 24/7 basis. These generators lower a customer's peak demand, and therefore the customer's demand charge, while their utility stands by to meet the customer's entire load if the generator fails. Solar energy generation ceases every night and dips during daytime due to cloud cover. For most commercial customers, this means that the utility will impose a demand charge based on peak demand that is nearly what the customer would pay without a solar generation facility. While residential customers typically do not have demand charges and can reduce their utility bills to nothing with NEM depending on facility size, the utility is still in the favorable position of receiving daytime energy that is more valuable than nighttime energy, and typically at least as valuable as early evening energy.

Because of these concerns, Freeing the Grid gives state programs that institute standby charges and other fees for net-metered systems fewer or even negative points. To the extent that proposed standby charges are based on actual rate impacts for a particular utility, institution of the charges is a policy choice available to regulators, but an NEM policy should be reviewed without standby charges to determine what rate impacts exist.

Relevant Studies For Evaluating Net Energy Metering Rate Impact

As solar has become a viable option for increasing numbers of consumers, considerable federal, state, and utility attention has begun to focus on valuation of solar energy from DG resources. The following three sections offer a review of recent solar valuation studies, recent efforts in California to develop a methodology for valuing demand-side resources including solar energy systems, and recent efforts to value the capacity benefits provided by solar energy systems. Synthesis of these efforts will provide insight into areas of consensus on the valuation of solar and, therefore, form the foundation of best practices for assessing the rate impacts of NEM.

Studies Valuing the Benefits of Solar Resources

There have been several efforts to value solar energy generation in specific locales, of which three stand out as particularly comprehensive. The first two are discussed in this section: The Value of Distributed Photovoltaics to Austin Energy and the City of Austin (Hoff et al., 2006, followed by a 2008 revision) (AE study) and Distributed Renewable Energy Operating Impacts and Valuation Study (R.W. Beck, Inc., 2009) (APS study). The third comprehensive study of solar energy valuation is incorporated within a broader review of the costs and benefits of net metering for California's largest IOUs. We review that study in the "California's Cost-Benefit Methodology for Distributed Energy Resources" section.

The Austin Energy (AE) and Arizona Public Service (APS) studies discussed below provide an in-depth look at the value solar photovoltaic (PV) generation can bring to the grid for a specific utility. Moreover, each study was subject to scrutiny from many perspectives and stakeholders, and, taken together, they represent a good starting point for identifying consensus elements of the value solar PV can bring to the grid.

Austin Energy Study

To support its determination to move forward with a goal of installing 100 MW of solar generation by 2020, Austin Energy commissioned Clean Power Research to quantify the benefits of solar generation to the utility. At the onset, the authors identified two perspectives as forming the core of the AE study—the "utility" perspective and the "all ratepayer" perspective—and the study's authors used these perspectives to inform the development of a methodology for valuing the benefits of distributed PV.

Based on the various perspectives, the AE study authors presented a comprehensive list of benefits stemming from distributed PV based on research performed by the National Renewable Energy Laboratory, and including the value of energy production, generation capacity value, transmission and distribution (T&D) deferrals, reduced transformer and line losses, environmental benefits, natural gas price hedge, disaster recovery, blackout prevention and emergency utility dispatch, managing load uncertainty, retail price hedge, and reactive power control. Ultimately, the last four potential benefits listed here were not included in the AE study for various reasons, and the benefits associated with disaster recovery were studied, but not included in the primary analysis. (Hoff et al., 2006, p. 12).

The AE study found that PV offered a present value of $1,983 to $2,938/kW or on a levelized basis between 10.9¢ and 11.8¢ per kilowatt-hour (kWh) in 2006 dollars. In a 2008 recalculation, Austin Energy found substantially higher average values of $3,139/kW and 16.4¢/kWh in 2008 dollars.

From the standpoint of NEM, when a customer receives a credit for excess generation that can be used when consumption exceeds generation, Austin Energy's residential retail rate as of December 2010 on tariff E01 (the standard residential tariff), including a fuel adjustment of 3.65¢/kWh, is approximately 7.2¢/kWh for less than 500 kWh of consumption per month, 9.67¢/kWh for consumption of more than 500 kWh/month from November through April, and 11.47¢/kWh for consumption of more than 500 kWh/month from May through October. All of these rates are well below the 16.4¢/kWh unadjusted value of the benefits PV brings to Austin Energy.

Discussion of AE Study

In reaching these figures, it is important to note that ultimately, two important benefits were not included in the final valuation—disaster recovery and reactive power control.

Disaster recovery benefits were not included because the quantification of this benefit was the first known attempt to do so by the authors and, therefore, the results did not have the level of certainty desired. Ultimately, the authors of the study recommended further study of the issue by Austin Energy in combination with battery storage especially in the context of a hybrid electric vehicle program. Disaster recovery benefits were estimated to be $2,701/kW for capacity and for energy generation to range from $1,121 to $1,578/kW. These numbers would almost double the overall value of PV generation to Austin Energy.

Voltage support and reactive power control had a value of $0/kW in the final model because current technical standards do not allow for this benefit to be provided by inverters for the benefit of utility operators. The study estimated the value of this benefit at up to $20/kW, but the figure could be much higher, and the technology to provide this benefit is available. At present, the technology may not be incorporated into inverters

pursuant to IEEE Standard 1547, the existing technical standard for interconnections. A working group of electrical engineers is developing a standard for interconnection of generation with inverters that provide reactive power and voltage support, which will become IEEE Standard 1547.8.

A recent study by the Electric Power Research Institute includes the graphic in Figure 2, displaying how voltage is less variable on a typical 12 kV circuit with solar energy and voltage control than it would be with no solar energy facilities at all. Already, New Jersey utility PSE&G (Public Service Electric & Gas Company) has mounted tens of thousands of individual solar modules on its power poles and is using the available voltage and reactive power support (as a utility, it does not need to wait for completion of IEEE 1547.8). Because of these developments, in any valuation of solar energy generation, it now seems reasonable to consider the value of voltage and reactive power support.

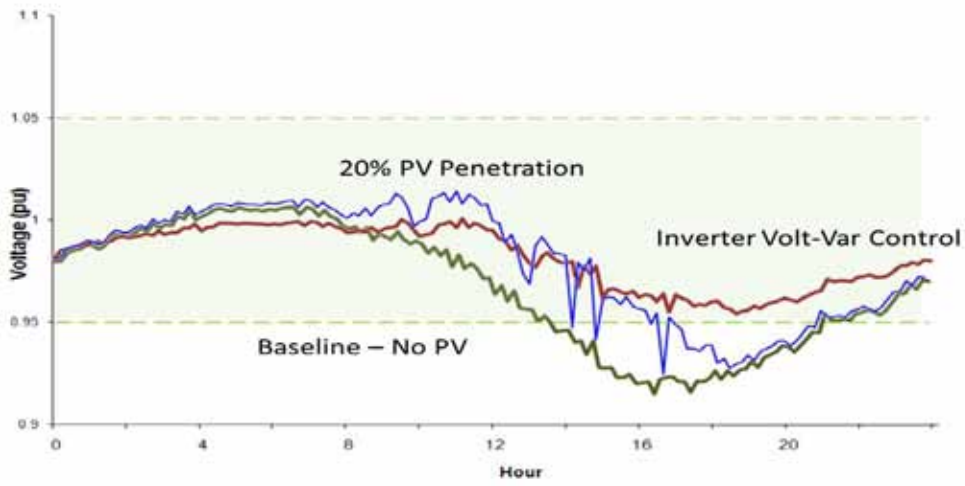

Figure 2. Percentage variation from rated voltage on a typical 12 kV line without PV (the green line, with lowest point), with 20% PV penetration without voltage and reactive power control (the jagged blue line), and with "Inverter Volt-Var Control" (the brown line, with the least voltage variability). Source: Seal, B., Monitoring, Information, and Control: Management for Tomorrow's PV (PowerPoint), May 2010 (reprinted with permission).

Arizona Public Service Study

In early 2008, Arizona Public Service (APS) commissioned R.W. Beck, Inc., Energized Solutions, LLC, Phasor Energy Company, LLC, and Summit Blue Consulting, LLC to assess the impact of wide-scale deployment of distributed PV along with solar hot water systems and commercial daylighting systems on the APS system. Among the specific objectives of the study was an assessment of the benefits wide-scale deployment of these technologies could have for the APS system. In this sense, the APS study views the potential benefits of deployment of distributed solar from the utility perspective. The APS study was conducted in an open process with the participation of many stakeholders from within the solar industry, the business community, advocates, and the regulatory community.

In constructing the methodology for reviewing the benefits of the three distributed solar technologies discussed above, the study's authors focused on low, medium, and high penetration scenarios, with generating capacity as a percent of peak demand reaching 0.5%, 6.4%, and 14% respectively by 2025 (Arizona Public Service, 2010, Tables 5-3 and 5-4). Within these scenarios, the authors made a number of assumptions about PV

capital cost reductions, the availability of federal tax credits, and the make-up of APS tariffs. The APS study also developed a target scenario that assumed APS would deploy solar technologies to achieve the greatest possible benefits. The target scenario included a general scenario and one in which all commercial PV used single-axis tracking.

The benefits identified in the APS study included reduction in T&D line losses, deferment of T&D capacity upgrades and additions, reduction in necessary equipment size within the distribution system, avoided electric generation capacity costs, avoided fixed operating costs, avoided energy purchases, and avoided fuel purchases. While labeled differently, this is a subset of the list used by the AE study, leaving off environmental benefits and the ability to provide a hedge on natural gas prices, as well as the four factors ultimately left out of the primary AE analysis (disaster recovery, blackout prevention and emergency utility dispatch, managing load uncertainty, retail price hedge, and reactive power control).

After detailed modeling, the APS study found a range of benefits across the various penetration and target scenarios of approximately 7.9¢ to 14.1¢/kWh in 2008 dollars, without reference to a particular scenario (Arizona Public Service, 2010, p. xxii). Residential rates for APS customers as of December 2010 were just under 9.4¢/kWh, ramping up in stages during summer months to 17.4¢/kWh for higher energy usage. Assuming benefits have increased with inflation, the APS study appears to be inconclusive regarding whether there is a subsidy flowing from residential ratepayers to NEM participants (calculated benefits at the lower end of the reported range are less than costs). For demand-metered customers, it seems that benefits exceed costs substantially.

An APS review of this report stated that benefits identified in the APS study were based on locating facilities optimally and maintaining utility ownership and control of the installations, although the benefits of optimal siting are not broken out separately in the APS study. The most likely benefit of selective siting would be for individual distribution circuits. Most transmission and generation benefits would accrue regardless of the location of NEM systems. Reported distribution system benefits are only 0 to 0.31¢/kWh, implying that the impact of selective siting is relatively modest.

Discussion of APS Study

Two important aspects of the APS study directly affect the extent of the benefits it found, and explain the substantial difference from the AE study results.

First, virtually no capacity benefits were identified for the years prior to 2025 and even then, the capacity benefits were only significant in the high penetration case. The study notes that capacity pricing is rolled into energy prices used to calculate the energy benefit, and in that sense, there is a capacity value. However, by "capacity benefit" we are only referring to deferral or avoidance of new utility-built generation and T&D. The APS study's rationale for not attributing capacity benefits was that T&D and utility generation investments are "lumpy" so it would take a great deal of DG to have an impact on those investment decisions. (Arizona Public Service, 2010, p. 6-9). This view takes a primary advantage of PV—the ability to be installed incrementally—and gives it no value until output from the PV installation fully displaces a new utility generator. APS notes that its Integrated Resource Plan calls for no new construction for the next seven to eight years because it has sufficient capacity at present, but the PV installed over the next eight years could push the need for new construction out further and should be attributed some value. APS expects that peak demand will grow by 4,170 MW from 2010 to 2025. (Arizona Public Service, 2010, Table 5-6) and it is reasonable to assume that even a modest level of DG would defer some quantity of system level

utility investments by a year or more, thereby saving ratepayers money by deferring investment in these lumpy assets. In conjunction with modest levels of demand response, as discussed later in this report, installed solar facilities could also provide APS with firm power, eliminating the need for at least some portion of its contemplated generation and T&D investments.

The APS study makes a jump from modest penetration levels in 2015 to high penetration in 2025 without analyzing impacts in between. Even the high scenario assumes only 63 MW of DG by 2015 (Arizona Public Service, 2010, Table 5-3), or roughly 0.7% of anticipated peak demand for APS in 2015 (Arizona Public Service, 2010, Table 5-4). By comparison, DG capacity in PG&E's service territory in California is more than 2% of PG&E's peak demand as of early 2011. While the APS study looks at 6.4% and 14% penetrations in 2025, it would have been interesting to present capacity benefits in the 2% to 5% range that are likely in earlier years.

The second significant deficiency in the APS study is that it does not consider the benefits at the optimal penetration level using the optimal orientation. Because the study is "forward looking" in so far as it is not assessing the impacts of a program as currently implemented, it would seem logical to have performed this analysis. Indeed, the study acknowledges that southwest facing modules or solar tracking will increase production per MW in the late afternoon, when APS experiences peak demand, and have a greater capacity benefit than a south facing array of the same size. However, the scenarios describing the benefits of DG under the low and medium penetrations do not appear to take the capacity benefits of deploying these optimally oriented arrays into consideration.

Interestingly, in the high penetration case, a solar tracking sensitivity analysis concludes that in 2025, tracking would shift the APS peak to a later hour, at which time the capacity benefit would be little more than it would be with a fixed array pointed south. However, this case envisions generating capacity of 1,677 MW (Arizona Public Service, 2010, Table 5-3), which would be 14.6% of peak demand. The analysis has thus skipped from a modest penetration of 0.7% (63 MW) in 2015 to a penetration of 14.6% in 2025 without looking at the optimal penetration that would occur in between. To its credit, the APS study does acknowledge that energy storage would increase the capacity value of solar energy systems, but it does not attempt to quantify the benefit.

Finally, the APS study did not attribute any environmental benefits to the utility or quantify natural gas hedging benefits as the AE study did. Inclusion of these benefits would have contributed to an overall valuation of the benefits to utility ratepayers from the solar resources modeled in the study. And like the AE study, the APS study did not attribute any value to the ability of solar generation to provide voltage and reactive power support or to provide disaster recovery benefits.

California's Cost-Benefit Methodology for Distributed Energy Resources

Starting in 2004 in Rulemaking (R.) 04-03-017, the California Public Utilities Commission (CPUC) embarked on an effort to develop a framework for valuing distributed energy resources. The overarching goal of the proceeding was to develop a methodology planners could use to compare demand-side resources in a consistent fashion across all resources—energy efficiency, renewable distributed generation, combined heat and power, etc. Efforts by numerous parties including renewable energy and combined heat and power advocates, CPUC staff, ratepayer advocates, and utilities to develop this methodology went on for a number of years and into successor distributed generation dockets R.06-03-008 and R.08-03-008. Stakeholders' efforts culminated in the issuance of Decision (D.) 09-08-026 on August 20, 2009.

In D.09-08-026, the CPUC established a methodology for valuing a wide range of distributed energy resources based on the approach used to value energy efficiency in California's Standard Practice Manual (SPM). In that vein, D.09-08-026 considers four tests described in the SPM for use in evaluating DG resources—the participant test, the rate payer impact (RIM) test, the program administrator (PA) test, and the total resource cost (TRC) test. Ultimately, the CPUC chose to use four tests—the participant test, the PA test, the TRC test, and the societal test—in evaluating DG resources. The societal test is very similar to the TRC test, but includes the impacts of externalities such as environmental costs/benefits, excludes tax benefits, and uses a different discount rate. Each of these tests views the costs and benefits of DG resources from different perspectives—the participating customer-generator (participant test), ratepayers generally (the RIM test), society (TRC and societal tests), and the program administrator, which in California is often the utility (the PA test).

Although D.09-08-026 does not require the use of the RIM test for a general evaluation of DG resources, the test is relevant to a discussion of the rate impacts of NEM because the RIM test attempts to compute bill and rate impacts due to changes in utility revenues and costs. D.09-08-026 identifies the following benefits within the RIM test—avoided T&D line losses, avoided energy and resource adequacy costs, T&D investment deferrals, environmental benefits, increased revenue from fuel transportation for natural gas-fired DG (not relevant for solar energy), and reliability benefits (ancillary benefits and volt-ampere reactive [var] support).

Unlike the AE and APS studies, the CPUC decision also identified costs, including net metering bill credits, program administration, reduced revenue from standby charge exemptions, lost revenue from non-bypassable charges, reduced T&D and non-fuel generation revenues, increased reliability costs for ancillary services and var support, cost of utility rebates or incentives, the cost of utility interconnection not charged to customer-generators, and increased utility fuel transportation costs for gas-fired DG (not relevant for solar energy).

Discussion of D.09-08-026

Inclusion of lost revenues must be handled very carefully in the context of NEM of intermittent resources such as solar and wind. In theory, the utility has a right to recover certain fixed costs under its standard tariffs, and NEM cuts into that expected recovery. However, great care must be taken to avoid double counting of costs. For instance, D.09-08-026 recognized that inclusion of lost standby charge revenue could result in double counting of lost T&D revenues, because standby charges developed in California were also designed to recover T&D expenses. Because both revenue streams would be recovering the same T&D expense, recovery of lost standby charge revenue along with recovery of lost T&D revenues could result in double counting of lost T&D revenues.

Additionally, practitioners must consider other factors when addressing lost revenue claims. First, utility standby charges are designed to recover the utility's cost of being constantly prepared to meet a customer's peak demand in the event that on-site generation is not functioning at the time of that peak demand. In the case of intermittent resources, it is a near certainty that generation will not be effective at some time during each billing cycle when the customer's demand nears the customer's peak demand. In other words, at those times, the customer's solar array is providing minimal generation to offset the customer's electricity consumption, and the customer will pay a demand charge based on almost all of the customer's peak consumption. For demand-metered customers in this situation, the demand charge resulting from their peak demand is

already at or very close to their peak consumption, so the utility is not standing by, it is providing the necessary power and charging for it already. Claiming that preclusion from billing standby charges is a utility cost is effectively claiming that the utility can bill the customer twice for fixed costs, which obviously is not correct. Double counting would almost certainly occur if potential lost standby charge revenue is included as an additional cost of the NEM of intermittent resources.

Moreover, although residential and small commercial customers do not face demand charges, the variability in their relatively small loads due to renewable generation has not been shown to have any significant impacts on the grid or been shown to be potentially any different than customers without renewable generation who have significantly varying loads from one moment to the next. Accordingly, requiring that these customers pay standby charges would be discriminatory in the absence of a cost of service study showing a clear justification for such charges.

These are not abstract concerns. For example, when Southern California Edison (SCE) undertook a more detailed review of its standby charges in light of the diversity of standby customer load compared to regular retail load, SCE found that the diversity of standby customer load was imposing significantly less cost on the distribution system than its regular tariffed customers. Accordingly, SCE redesigned its standby charge rates by reducing demand charges when compared to regular tariff services. Looking at this change in reverse, prior to the change in demand charges, standby customers were significantly overcompensating SCE under its prior standby charges. It would be useful to see whether customer investment in renewable energy similarly results in a greater diversity in their load when compared to typical retail customers, and has a similarly less taxing impact on the grid.

In sum, inclusion of lost utility revenue related to standby charges has some logical appeal and merit, but care must be taken to avoid double counting. Moreover, standby charges and T&D charges designed to recover costs from ratepayers who have not invested in DG resources may overcompensate the utility in the absence of cost of service studies specific to DG customers, which would set these fees in that context. That is, calculating lost revenues based on these tariffs could overstate the amount of the utility's lost revenue.

California's Net Energy Metering Cost Effectiveness Evaluation

In late 2008, the CPUC commissioned Energy and Environmental Economics, Inc. to value the excess generation produced by net-metered systems for the state's three largest IOUs—Pacific Gas & Electric (PG&E), SCE, and San Diego Gas & Electric (SDG&E). The resulting study, Net Energy Metering (NEM) Cost Effectiveness Evaluation (Energy and Environmental Economics, Inc., 2010) (E3 study), was publicly issued in March 2010 (dated January 2010). The study delves into detail by utility, customer class, customer size, and location not seen in any other study.

E3 Study Overview

As part of its focus on the costs and benefits of net-metered solar generation from the utility perspective, the E3 study provides the country's first comprehensive look at the rate impacts of NEM, making it uniquely important in this report. Although it does not reference the RIM test discussed above, the E3 study relies heavily on the analysis performed in D.09-08-026. Because of that fact, despite the groundbreaking nature of the E3 study, many of the flaws and concerns discussed above are present in the E3 study.

The benefits of NEM provided in the E3 study are similar to those in the AE and APS studies. For the E3 study, they include avoided costs from avoided energy purchases, avoided generation capacity or resource adequacy, avoided line losses, avoided T&D capacity, avoided environmental compliance, avoided ancillary services, and avoided renewable energy purchases by the utilities under California's Renewable Portfolio Standard.

On the cost side of the equation, the study evaluated the cost of bill credits provided to NEM participants, administrative costs, and interconnection costs (under California law interconnection costs are not billed to NEM customers).

While the complexity of the analysis in the E3 study precludes a detailed discussion of the methodology here, one example highlights the comprehensive nature of the study. Recognizing that the impact of NEM will not be uniform for all customer-generators, the E3 study models the impacts in 1,253 distinct customer-groupings based on utility, customer type, facility sizing in relation to customer load, and location. (Energy and Environmental Economics, Inc., 2010, p. 29) The complexity of such an undertaking is daunting, but it is important to accurately reflect the timing, size, cost, and benefits of exported energy. Additionally, to further explore the impact of certain cost assumptions on the analysis, the E3 study includes a sensitivity analysis related to billing costs, T&D avoided costs, standby charges, and interconnection costs.

Overall, the E3 study finds that current rate impacts average just over a hundredth of a cent for every kWh purchased (0.011¢/kWh, Energy and Environmental Economics, Inc., 2010, Table 4). Delving more deeply into the average figure, the results for each utility were 0.018¢/kWh for PG&E, 0.0005¢/kWh for SCE, and 0.0009¢/kWh for SDG&E. These are truly small figures; utility rates often rise by a penny or more per kWh in a utility rate case, and the figures here are all less than a fiftieth of a cent.

Looking to the future, the E3 study finds that by 2020, 2,550 MW of net-metered solar generation will result in a 0.38% increase in utility rates or 0.064¢/kWh (Energy and Environmental Economics, Inc., 2010, Table 5). In 2020, 2,550 MW of generation would be 3.7% of forecast peak load of just over 60,898 MW for the three utilities. (California Energy Commission, December 2009, p. 51—adding coincident peak demands for PG&E, SCE, and SDG&E). Taking the facts provided here, for every 1% of solar generation, as a percentage of utility peak demand, the E3 study indicates a 0.1% impact on utility rates.

Discussion of the E3 Study

Although the E3 study concludes that NEM at the California IOUs entails a modest subsidy of customer-generators by other ratepayers, several assumptions drive that conclusion.

First, an important assumption made in the E3 study is that the rate impact of NEM is limited to the impact of exported energy. The study notes that customers can generate electricity without NEM, but would not be able to export. With this approach, rate impacts related to energy used on site at the time of generation are not impacts of NEM, they are impacts related to solar generation generally. The study notes that 243 customer-generators with a total of 43 MW of generating capacity do not export at all, and are excluded from the impact analysis entirely. (Energy and Environmental Economics, Inc., 2010, p. 14). While the E3 study does not say it, this approach implicitly assumes that without NEM in place to support customer-generators, customer-generators would have installed the same amount and type of generation, would not have changed

their consumption patterns to make better use of their renewable energy investments, and, finally, that excess generation would be delivered to utilities for minimal compensation. This is not a likely outcome.

In the absence of NEM, there would still be federal and state incentives to install solar energy facilities along with the incentive of offsetting coincident customer load, but customer-generators would likely behave differently. On the one hand, some facilities might be sized smaller to reduce the amount of excess generation. Exported energy could still be sold at the utility's avoided cost in accordance with federal law, but that is less than retail rates, and customers could be expected to react to that lower payment. On the other hand, customers would be likely to try to better coordinate generation and consumption in the absence of NEM, to increase the percentage of generation used on site. For example, air conditioning equipment could be operated in conjunction with generation, cooling more at mid-day and less in the late afternoon. As well, customer-sited batteries could allow customers to synchronize inter-day generation and load for a modest additional investment.

It would be difficult to model generation and load in the absence of NEM, and it is understandable that the E3 study made the simplifying assumption that customers with solar energy facilities would not attempt to match generation and load in the absence of net metering. However, as a practical matter, the reported rate impact of NEM is probably overstated, because customer-generators would modify their behavior in the absence of an NEM program.

Second, it is important to recognize that the E3 study bases costs on the rates that utilities would have charged customer-generators, and California's IOUs have some of the highest residential rates in the country. For example, a residential customer exporting 1,000 kWh in a year will get a credit for 1,000 kWh from the customer's utility, which means the utility did not have the opportunity to sell that amount of energy to the customer for as much as 40¢/kWh. In many parts of the country, top residential rates are less than 10¢/kWh, and utilities' lost revenue from NEM is therefore much lower.

Additionally, the E3 study suffers from several deficiencies that, when looked at cumulatively, greatly decrease the value of the benefits from the energy provided by net-metered customers. Most importantly, the study finds that the utilities have limited need for additional capacity until 2015, so the study provides customer generation with limited credit for capacity value until after 2015. The E3 study values capacity starting at $28/kW/yr in 2008 and increases linearly to $141/kW/yr in 2015, then increases at a more modest pace to more than $200/kW/yr by 2036 (Energy and Environmental Economics, Inc., 2010, Appendix A, p. 15-16).

Broadly, this assumption implies that utility planning occurs without consideration of customer generation, and accordingly assigns a limited capacity value for customer-sited generation. This assumption simply does not square with current practice in California for a number of reasons. First, long-term resource planning in California does include customer-sited generation because the utilities' long-term resource acquisition plans rely on load forecasts based on historical loads that include customer-sited generation and anticipated future customer-sited generation. Second, the California Energy Commission recently denied an application to build the natural gas fired Chula Vista plant based partly on the fact that significant solar DG would be coming online. So both in theory and practice, customer-sited DG is being taken into account in long-term decision-making on the need for generating capacity.

Interestingly, the E3 study's valuation of the capacity benefit of NEM solar generation is considerably lower than the likely valuation of capacity for solar energy purchased by California utilities under long-term contracts. While still under consideration, it appears that the market price referent (MPR) will be used for these contracts (other than the contracts under the Renewable Auction Mechanism). The MPR is based on the total cost of generation for a natural gas combustion turbine, including capital costs, and thus incorporates capacity value. It has been argued that solar energy under contract has more value than NEM solar energy because there is no assurance that the latter will continue to operate. However, there is no reason to expect widespread decommissioning of NEM systems. Having paid to install their systems, NEM customers are unlikely to remove them and forgo utility bill savings, and there are very few instances of such actions to date. It seems reasonable to give NEM generation the same capacity credit accorded to solar energy purchased under long-term contracts.

To highlight the significance of this flaw in the study's methodology, an added capacity value of even a $20/kW/yr increase, applied to 2,550 MW of solar generation, is $51,000,000 per year—a significant added benefit that would negate much of the net cost per year of NEM in the E3 study. For other states and utilities attempting to value capacity, the lesson is that to properly determine capacity value, a base assumption should be that the generation was anticipated, or should have been anticipated, and its value should not be assessed after the utility has made its generation choices and has sufficient generation. At the margin, a prudent utility has sufficient capacity and there is limited value to adding more capacity.

The other important factor not considered in the E3 study is reactive power and voltage support, as discussed earlier in this report. D.09-08-026, identified var support as an NEM cost, presumably based on the assumption that fixed-voltage inverters on solar energy facilities might cause greater voltage fluctuations on the circuit. As discussed earlier, new technology and revised standards will allow inverters to provide adjustable voltage support and var control. While current utility infrastructure does not enable utilities' use of these functions, the implementation of smart grid with associated communications and controls enhancements offers the strong potential to turn this presently deemed cost into a future benefit.

Administrative costs are identified in the E3 study as well, based on reported utility costs. Monthly incremental administrative costs for residential net-metered customers are a reported $18.31 for PG&E, but only $3.02 for SCE and $5.96 for SDG&E. (Energy and Environmental Economics, Inc., 2010, p. 40) As noted above, to further explore the impact certain cost assumptions have on the results, the study performed sensitivity analysis. As part of that analysis, the study took a closer look at administrative costs, including a sensitivity analysis based on no administrative cost (the base case accepts the PG&E cost). This sensitivity analysis resulted in a 27% decrease from the base case. This sensitivity analysis is reasonable to consider because, while in practice there is some minor administrative cost per customer, that cost is likely to drop with automation and high volume. An overstatement of $12/mo for systems averaging 6 kW in PG&E's service territory is equivalent to roughly $24/kW/yr, implying an added cost of roughly $24,000,000 per year, which seems unreasonable.

Automation of billing to handle NEM over the long term is sensible as part of an overall update of utility billing software to support the move to a smart grid that supports distributed generation. A holistic view of the necessary changes to utility billing practices is also required to support investment in the smart grid. These changes include the need to accommodate NEM, demand response, advanced energy storage, vehicle

electrification, and other necessary initiatives. All of these long-term policies have been identified as necessary to meet climate and environmental goals and therefore should not be viewed in isolation. In particular, smart metering has been justified based on traditional utility cost savings, and should allow administrative costs for NEM and other programs to drop to very low levels.

As noted earlier, it is critical to recognize that California IOUs have tiered rates as high as 40¢/kWh, so the lost-revenue cost to the California IOUs is two to five times higher than most utilities in the United States. In fact, the top rate at PG&E contemplated in the E3 study was 50¢/kWh, although that tier has since been eliminated.

Quantifying the Capacity Value of Solar

Because the capacity value for PV has been a particularly thorny issue in determining the value of solar resources for utilities, it is worthwhile to provide more discussion on this topic. For many utilities, peak demand typically occurs in the late afternoon. This fact is often cited as a key reason to dismiss the ability of solar to provide significant capacity benefits. However, depending on the actual hour of peak demand, modules can be oriented to the southwest to enable them to operate near their rated capacity in the late afternoon. Careful program design that encourages customers to orient their solar resources to meet a later system peak can address this concern. As discussed in the APS study, southwesterly oriented modules operate at more than two-thirds of rated capacity from 5:00 to 6:00 pm on a sunny summer day and at half of rated capacity from 6:00 to 7:00 pm. Moreover, modules pointed southwest are operating at only slightly less than their rated output between 3:00 and 4:00 pm, which was the peak load in California for 2008 (Self Generation Incentive Program Impact Report, 2008 revised).

The second challenge to solar energy's ability to provide capacity reliably is that cloud cover can dramatically impact an individual system's performance on short notice. In practice, the effect of cloud cover on a single solar energy system is not simultaneously felt across a whole region, and much of the variability is not even seen across a distribution circuit with multiple MW of interconnected generation. Perez et al. showed that just twenty systems over a limited service area will have a collective output with almost no variability on a partially cloudy day, despite the variability of each one of the systems individually (Perez et al., 2006). Likewise, researchers at Lawrence Berkeley National Laboratory recently calculated the smoothing effect of distributed solar power, finding that the relative aggregate variability of PV systems decreases with increased geographic diversity. That study showed aggregate variability over a 15-minute period is one-sixth of the variability of a single PV system, and over a one-hour period, it is one-third of the variability of a single PV system (Mills & Wiser, 2010).

Demand response or energy storage coupled with PV can play a role in meeting peak demand if peaking generation is not available at lesser cost. In a 2006 study, Perez et al. (Perez et al., 2006) analyzed the peak-month loads for three utilities and the coincidence of available solar generation. Stunningly, almost all of the loads above 90% of the utilities' peak load could be met with solar energy, with a minimal contribution provided by demand side management to fill in the gaps, as shown in Figure 3. In practical terms, these results show that solar energy is able to provide reliable energy peaking generation as needed with only a modest addition of demand side management.

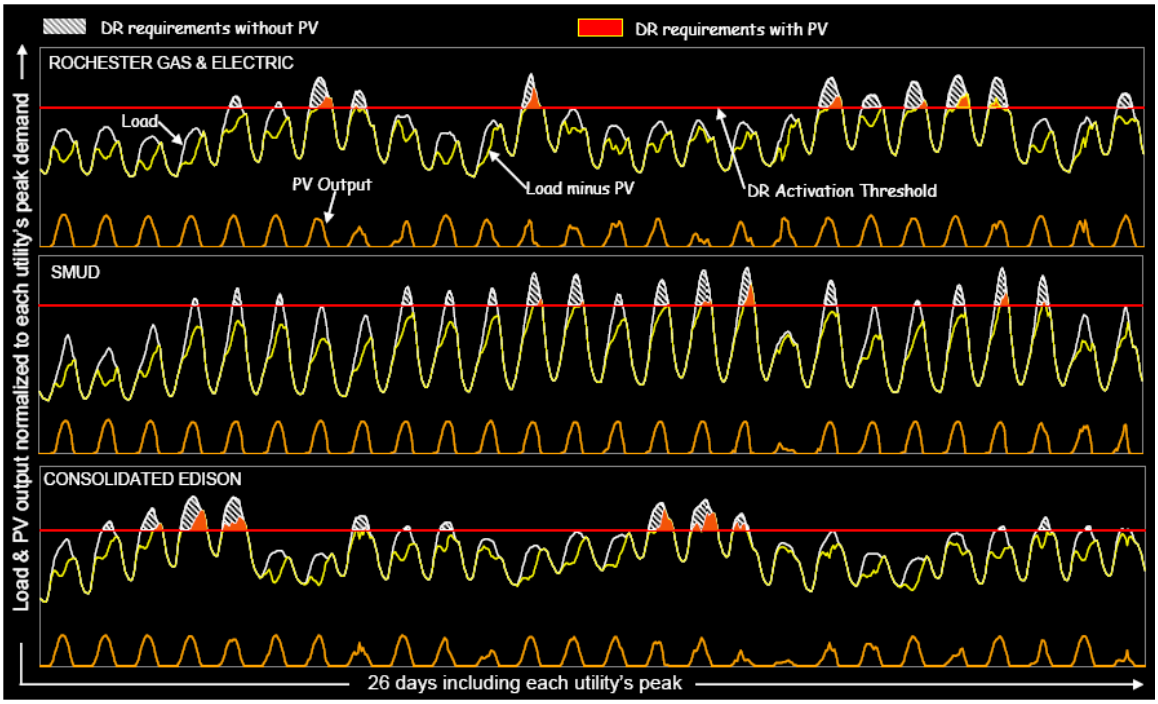

Figure 3. Integration of PV in demand response programs, using PV rated capacity of 20% of utility peak demand and showing the peak line at 90% of utility peak. Solid shading indicates periods of demand side management. Source: Perez et al., 2006.

In sum, research has demonstrated that many of the concerns that lead utility planners to discount the capacity value of PV can be addressed through program design, careful analysis of potential benefits from diffusion of solar resources, and coupling PV with demand response and energy storage. Based on these points, it is unreasonable to dismiss any capacity value to solar energy for a particular utility without considering these issues.

BEST PRACTICES IN VALUING NET ENERGY METERING

Given the recent efforts to value solar resources discussed in the "Relevant Studies" section, one can begin to see a relatively clear picture of the necessary inputs in a methodology to value solar resources.

Costs of Net Energy Metering from a Rate Impacts Perspective

On the cost side of the methodology, although the AE and APS studies did not attempt to develop a methodology for consideration of NEM costs, the two main inputs developed in D.09-08-026 for the RIM Test—NEM bill credits and program administration costs—are unsurprising and could be relatively noncontroversial if they are carefully developed.

As we have noted, careful calculation of NEM bill credits is important to avoid double counting of costs. CPUC D.09-08-026 suggests that costs should include reduced T&D and non-fuel generation revenues and lost potential revenues from a standby charge exemption. If NEM bill credits are determined by comparison of estimated bills before and after renewable resources are installed, "revenue losses" related to T&D charges and non-fuel generation revenues are already included. Moreover, customers who face demand charges based on maximum demand during the billing period could see little or no change in their demand charges, and thus would still be paying the T&D and non-

fuel generation costs. For these reasons, inclusion of an additional input to measure T&D and non-fuel generation charges not collected by the utility due to NEM of solar and wind facilities is almost certainly double counting of this potential "lost revenue."

Depending on how standby charge tariffs are actually implemented by a particular utility, calculating the potential lost revenues from a standby charge exemption would double count T&D charges again. Inclusion of lost standby charges is also troublesome because standby charges have usually not been developed for intermittent DG resources and, therefore, are not based on the cost of serving these particular customers. To its credit, the E3 study considered this "lost revenue" in a sensitivity analysis, but did not consider it in the base case.

Caution concerning program administration costs is also warranted. While it might be intuitive to include the actual costs the utility estimates it has incurred in administering its NEM program, it is clear from the E3 study that critical review is necessary. As discussed in the prior section, self-reported administrative costs at PG&E were nearly quintuple the costs reported by SCE and SDG&E with no explanation for this disparity. While some variation in costs is reasonable, a cost spread of this magnitude should raise concern and be justified before inclusion in any cost-benefit analysis. Moreover, as utilities begin to implement billing system updates to handle smart meters, demand response/control functions, and other emerging policies, those systems should be designed to handle NEM more efficiently, and the incremental costs of NEM should decline to slightly more than zero.

Benefits of Net Energy Metering from a Rate Impacts Perspective

On the benefits side of the equation, each study discussed in this report finds that avoided T&D line losses, avoided capacity and energy purchase costs, and avoided T&D investment deferrals should be included as benefits (though the studies did not agree on how to account for the benefits). Inclusion of these benefits in a methodology to assess the possible rate impacts of NEM should be relatively noncontroversial given their consistent identification as benefits of customer investment in renewable energy resources. Avoided line losses stem from locating the generation source on site, which allows line losses due to transmission from distant generation sources to load to be almost completely avoided (there are very modest losses associated with excess generation stepping up to utility line voltage then back down when used nearby on the same circuit). Avoided capacity and energy purchase costs stem from the reduction in on-site customer load and export of excess energy. T&D investment deferrals stem from decreased customer load at the feeder, substation, and transmission levels, and can include deferrals of investment and postponing of investment in T&D upgrades. Care should be taken to ensure evaluation of T&D investment deferrals includes not only the deferral of capacity investment but also equipment and operations and maintenance, as both the APS study and D.09-08-026 recognize these value streams.

Moreover, both the AE study and the E3 study recognize that renewable resources can provide environmental benefits due to avoided emissions from non-renewable energy sources. These benefits are a direct consequence of the investment by customers in generation sources that emit few or no pollutants during their production of energy. While the AE study and E3 study took different approaches to valuing this benefit, given regulatory frameworks in place for the measurement of NO_x, SO_x, and particulate matter, and efforts to regulate CO_2, assessment of the environmental benefits of renewable resources should not be excluded as a benefit. The ability to mitigate carbon regulatory risk is particularly valuable. The CPUC Self Generation Incentive Program Eight-Year Impact Evaluation Revised Final Report (Itron, Inc., 2009) finds that PV was able to

mitigate approximately 0.58 tons CO_2 per MWh. Given forecasts of future carbon prices in the range of $15 to $45 per ton on a levelized basis between 2013 and 2030, this would suggest a value of approximately $9 to 26/MWh in avoided carbon on a levelized basis. (Schlissel et al., 2008)

Additionally, consideration should be given to the possible benefits customer-sited renewable resources will have on a utility's obligations to purchase renewable energy to meet state mandates as discussed in D.09-08-026. For example, because the California Renewable Portfolio Standard bases each utility's compliance obligation on retail sales, utilities will be able to avoid purchases of renewable generation they might have otherwise been required to purchase because customer-sited generation lowers a utility's retail sales. For this reason, D.09-08-026 finds that a typical avoided cost methodology might not fully capture the benefits of customer-sited renewable resources in avoiding renewable generation additions by utilities to meet their RPS obligations. States like Arizona and Colorado with similar RPS obligations should take care to ensure this benefit is appropriately assessed in their cost benefit methodology.

The AE study and D.09-08-026 also recognized that customer investment in renewable energy resources could have significant impacts on the natural gas market. The AE study identified the ability of PV to act as a hedge on natural gas price increases, and D.09-08-026 recognized that customer investment in renewable energy could decrease the demand for natural gas and thereby lower the market price of natural gas for all participants. Unfortunately, it concluded that the impact is too small and too difficult to discern at current DG penetration levels.

The conclusion that renewable energy has no impact on natural gas prices is not supported by research. A Lawrence Berkeley National Laboratory study (Wiser, Bolinger, & St. Clair, 2005) provides a detailed review of studies assessing this benefit. These studies show that the price impacts in terms of $/MWh of renewable energy additions are significant, ranging from $10/MWh to $65/MWh nationally. Regional impacts were also evaluated. For example, the Lawrence Berkeley study found the impact of approximately $5/MWh within California. Similarly, the price hedge for natural gas was estimated in the California Energy Commission's 2007 Integrated Energy Policy Report at approximately $12/MWh. Given many utilities' substantial and increasing reliance on natural gas fired generation and consumer level consumption of natural gas, natural gas price impacts should not be ignored when estimating the rate impacts of NEM. Each of these benefits are significant and well documented and, therefore, worthy of inclusion as a benefit of customer-sited investment in renewable energy.

Regarding reliability, D.09-08-026 addressed only one part of the likely benefit of DG and arbitrarily set the value of other reliability benefits at zero. The decision concluded that demand reductions due to DG resources are likely to lead to the same reliability benefits that result from energy efficiency measures and the existing methodology to calculate that impact should be used for the present time. However, it only acknowledged that DG has the potential to provide ancillary services and var support. This ability has been widely acknowledged for inverter-based systems, although output voltage is typically preset rather than being reactive to utility grid voltage, so the ability to provide support is not used at present. However, this ability is very likely to be tapped, at least for larger solar facilities, and could add significant value. Even more importantly, the AE study properly noted that DG has the potential to provide backup power to both critical need customers and typical utility customers. The AE study placed a very high value on this functionality and it seems that some estimate should be made of this value. D.09-08-026 simply set var support and backup power values at zero, but properly directed that those values should be estimated.

Based on the three solar valuation studies reported here, best practices in developing a methodology for evaluating the rate impacts of net metering counsel for including the inputs noted in Table 2.

TABLE 2
Necessary Costs and Benefits Inputs in a Methodology for Evaluating the Rate Impacts of Net Energy Metering

Benefits to the Utility	Costs to the Utility
Avoided Energy Purchases	NEM Bill Credits
Avoided T&D Line Losses	Program Administration
Avoided Capacity Purchases	
Avoided T&D Investments and O&M	
Environmental Benefits—NO_x, SO_x, PM, & CO_2	
Natural Gas Market Price Impacts	
Avoided RPS Generation Purchases	
Reliability Benefits	

CONCLUSION

To date, views concerning the possible rate impacts of NEM programs have driven many of the policy deviations from best practices in NEM in many states. However, very little rigorous analysis of the relative costs and benefits of NEM has been done. In reviewing the major net metering and PV cost-benefit studies performed to date, we identified the benefits noted at the end of the previous section as essential for inclusion in any study of the possible NEM rate impacts.

On the cost side of the analysis, the three studies provide guidance as well. The primary cost of NEM is the utility's lost revenue from utility ratepayers, equal to what ratepayers would have paid had NEM not been available. As the E3 study did, we recommend that the lost ratepayer revenue only focus on the bill impacts directly attributable to NEM (i.e. directly attributable to providing value to excess generation). The lost revenue due to NEM should not be based on all production from customer-sited generation, because a customer can install a system to offset their energy needs without an NEM program in place. While simplifying assumptions—that the amount of generation installed would not change or other measures would not be taken to store excess energy for later consumption, for example—are necessary, given the relatively small percentage of generation that is actually net metered, such simplifications seem reasonable.

In addition, utility administrative costs should be included, as discussed in the E3 study. However, the variance in administrative costs among the three California utilities surveyed indicates a need to review cost claims carefully. An assumption regarding future administrative cost reductions per kWh should be included to account for automation of processes. Other costs can be considered based on any unique features of a state's net metering program, but they should be carefully considered to ensure they actually stem from a state's decision to allow net metering versus a decision to allow customer-sited generation as a general matter.

E3's pioneering work quantifying the benefits and costs of California's NEM program highlights the fact that further research is necessary to arrive at consensus on the appropriate methodology for quantifying these benefits and costs. However, the inclusion of the benefits listed at the end of the prior section should be relatively noncontroversial in most instances. As noted earlier, the cost-benefit analysis is utility-specific, and some utilities may realize little benefit from one or more of the items noted in Table 2. A utility in a state without an RPS will not have any savings associated with avoided RPS purchases. A winter-peaking utility will not have a substantial capacity benefit.

Based on the review undertaken in this report, it would be difficult to conclude that nonparticipating customers subsidize demand-metered customers with NEM facilities. The cost to the utility of demand-metered customers deploying NEM is the loss of energy charges, but those energy charges are based on the variable costs that the utility avoids by not having to provide the energy that is instead generated on site. The administrative cost in the long run should drop to almost nothing per kWh, and the non-energy benefits discussed here will still be provided. It appears that demand-metered customers with NEM facilities will typically provide a net benefit to nonparticipating customers.

For customers with bundled rates, such as residential customers, whether or not there is a net benefit will depend on utility-specific costs and benefits.

RECOMMENDATIONS

We recommend that utility regulators wishing to determine the NEM rate impact for specific utilities use the guidelines provided in this report. In particular, we recommend that:

- Studies comparing the costs and benefits of NEM include the costs and benefit inputs identified in Table 2 above.
- As part of this effort, none of the benefits identified in Table 2 should arbitrarily be set to zero based on unsupported assumptions.
- Capacity benefits associated with deferral of utility generation and T&D facilities should be modeled under a long-term framework to ensure that the value of PV to defer these resources under a long-term planning framework is properly captured.
- Assessment of the costs and benefits of net metering should be based only on exported energy, not the entire production of the facility.
- Program administrative costs should be based on a long-term assessment of costs based on the expectation that updating utility billing software to accommodate and support grid-modernization efforts, which include net metering, will be necessary.

At the earliest stages of a NEM program, the cost of such studies may be greater than any net costs or net benefits themselves, and regulators may understandably be hesitant to undertake studies prior to significant NEM deployment. The results discussed in this report should give regulators confidence that rate impacts at the earliest stages will be negligible and need not be a concern that leads to restrictive NEM policy.

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Appendix A

Summary of Costs and Benefits Inputs Used in Three Solar Valuation Studies

	Austin Energy Study	APS Study	CPUC E3 NEM Study
BENEFITS			
Energy production value	X	X	X
Generation capacity value	X	X	X
T&D deferrals	X	X	X
Reduced transformer losses	X	X	X
Reduced line losses	X	X	X
Environmental benefits	X		
Natural gas price hedge*	X	X	
Blackout prevention*	X		
Emergency utility dispatch*	X		
Managing load uncertainty*	X		
Retail price hedge*	X		
Reactive power control*	X		
Reduced distribution system size		X	
Avoided fixed operating costs		X	
Avoided environmental compliance			X
Avoided ancillary services			X
COSTS			
Net metering bill credits			X
Program administration**			X
Reduced standby charge revenue***			X
Costs of interconnection not charged***			X

* These benefits were not quantified in the Austin study. The study found that the benefits were real and quantifiable, but there was insufficient data to assign them a value for Austin Energy.

** Because of data problems with utility reported billing costs, these costs were also included in a sensitivity analysis.

*** These benefits were included as sensitivity analysis.

ACRONYMS

AE	Austin Energy
APS	Arizona Public Service
CPUC	California Public Utilities Commission
D.	decision
DG	distributed generation
IOU	investor owned utility
kW	kilowatt
kWh	kilowatt-hour
MPR	market price referent
MW	megawatt
NEM	net energy metering
NNEC	Network for New Energy Choices
PG&E	Pacific Gas & Electric
PA	program administrator
PV	photovoltaic
R.	rulemaking
RIM	ratepayer impact
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SPM	California's Standard Practice Manual
TRC	total resource cost
T&D	transmission and distribution
var	volt-ampere reactive

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www.solarabcs.org

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Small Generator Interconnection Procedures Screens

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Executive Summary

Public demand for customer-owned distributed generation, especially grid-tied photovoltaic (PV) systems, has encouraged federal and state legislation calling for practical procedures for interconnection of non-utility-owned generators to the electric grid. Existing procedures have evolved over the last decade as states and the federal government sought to implement and improve upon early efforts. Early efforts were often unsatisfactory, because high costs, lengthy timelines, bureaucracy, and uncertainty proved to be formidable barriers. Fortunately, much has been learned during the last decade and "best practices" have begun to emerge.

The Federal Energy Regulatory Commission (FERC) Small Generator Interconnection Procedures (SGIP) apply only to facilities subject to the jurisdiction of FERC, but may serve as a model for state-level interconnection procedures. FERC SGIP was developed and published in 2005 through the efforts of utilities, regulators, industry representatives, consumer and environmental advocates, and other interested parties. According to paragraph 4 of FERC Order 2006, the National Association of Regulatory Utility Commissioners (NARUC) was a key contributor to the FERC SGIP. Regulators anticipated the need to update the small generator rules in FERC's Final Rule, which stated that "beginning two years from the issuance of this order, [we will] consider and recommend consensus proposals for changes in the Commission's rules for small generator interconnections" (FERC Docket RM02-12-000, 2005). There has not been a substantial review yet and the present study is intended to assist with such a review.

To obtain input, we asked 154 subject matter experts (SMEs), composed primarily of the Institute of Electrical and Electronics Engineers (IEEE) 1547.6 and 1547.7 Working Groups, to complete an online questionnaire concerning the need to update the FERC SGIP fast track screens and the 10 kilowatt (kW) Inverter Process in light of current available experience, data, and best practices. We report the responses of the 37 SMEs who replied to the questionnaire, and we also reviewed and considered recent National Renewable Energy Laboratory (NREL) technical reports. The SMEs' responses about each of the various screens ranged from strong consensus for a need to update some screens to general agreement that other existing screens do not need to be changed. Consensus was defined as support from two-thirds of the respondents.

Summary of Recommendations

Solar America Board for Codes and Standards (Solar ABCs) presents these recommendations with the intent that they will serve as the first step toward the update of the FERC SGIP.

Based on SME consensus, FERC and NARUC should collaborate to update the following FERC SGIP screens. FERC and NARUC will need to develop the technical details for each update.

Screen 2.2.1.7: The limit placed on the size of the aggregate generation on a single phase shared secondary should be updated to be in terms of a percentage of the transformer nameplate power rating.

Screen 2.2.1.9: The stability requirement should be rewritten for clarity.

Screen 2.2.1.3: Area networks should be covered in addition to spot networks. In addition, limits on maximum load should be revised upward in keeping with recent rules enacted in Connecticut and by Consolidated Edison in New York and with the guidelines defined in the IEEE 1547.6, which went to ballot in mid-June 2010.

For the following screens, the SMEs did not reach consensus, but many respondents made strong arguments for updates. These arguments are worth considering, because these screens have the potential to have the greatest impact on the reduction of barriers to high penetrations of PV. The U.S. Department of Energy (DOE) and/or the national laboratories should conduct technical studies of the issues covered in these two screens.

Screen 2.2.1.2: Further investigation and research is needed to determine whether to increase (and by how much) the current 15% limit on generating capacity related to circuit peak load (or whether to change the limit to relate to the circuit minimum load). Researchers should also consider separate treatment of inverter-based generation.

10 kW Inverter Process Size Limit: Further dialogue, and perhaps some research, is needed to determine whether to increase (and by how much) the limit from 10 kW for the simplified inverter interconnection process.

There was not a consensus for updating any of the remaining fast track screens reviewed by the SMEs. Therefore we make no recommendation for change to those screens. In addition, we recommend ensuring that utilities follow the same procedures imposed on other generators. The passage of the investment tax credit (ITC) has profoundly changed the utility role in the distributed generation market in general, and the PV market in particular. Therefore, FERC and NARUC should consider developing an enforceable non-discrimination policy or rule to ensure uniform application of the technical requirements to all distributed generation systems, including utility-owned distributed generation systems.

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Solar America Board for Codes and Standards

The Solar America Board for Codes and Standards (Solar ABCs) is a collaborative effort among experts to formally gather and prioritize input from the broad spectrum of solar photovoltaic stakeholders including policy makers, manufacturers, installers, and consumers resulting in coordinated recommendations to codes and standards making bodies for existing and new solar technologies. The U.S. Department of Energy funds Solar ABCs as part of its commitment to facilitate widespread adoption of safe, reliable, and cost-effective solar technologies.

For more information, visit the Solar ABCs Web site:

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Acknowledgements:

We wish to thank Gary Nakarado, J.D. of Regulatory Logic LLC and Thomas Basso of the National Renewable Energy Laboratory for their critical input and observations.

This material is based upon work supported by the U.S. Department of Energy under Award Number DE-PS36-07GO97005.

Table of Contents

Disclaimer ii
Executive Summary iii
Summary of Recommendations iii
Author Biographies v
Table of Contents vii
Introduction 1
Background 1
Overview of FERC SGIP Screens 3
Status of Distributed Generation 2010 4
Methodology 5
Results and Recommendations 7
Summary of Recommendations 11
Acronyms 13
Glossary 14
References 15
Appendix I: DG System Types and Characteristics 17
Appendix II: Detailed Results of Questionnaire 17
Appendix III: Survey Monkey Questionnaire 30

Introduction

The experience gained over the last decade confirms that distributed generation (DG) is far more likely to be deployed if developers and utility customers can readily discern the costs of interconnection and the length of time required for the interconnection approval process. Although regulators have a challenging task in formulating interconnection procedures, the benefits of implementing procedures that function effectively are substantial.

Solar America Board for Codes and Standards (Solar ABCs) identifies major gaps, barriers to deployment, or other issues in current codes and standards. These issues are prioritized to develop a strategy for the Solar ABCs' annual work plan. The first Solar ABCs paper on the topic of this report was published in 2008, and titled *Comparison of the Four Leading Small Generator Procedures* (Keyes & Fox, 2008). The report reviewed the four sets of interconnection procedures that regulators often consider when developing state and local procedures.

The report at hand is the second phase in the Solar ABCs strategic plan to examine the Federal Energy Regulatory Commission (FERC) Small Generator Interconnection Procedures (SGIP), and focuses on the FERC SGIP fast track technical screens. Section 2.2.1 of the FERC SGIP contains several screens used to fast track interconnection (FERC, 2005), and some of those screens may be unnecessarily restrictive. Revising these screens to simplify interconnection and increase the number of systems that pass the fast track screens (and the 10 kilowatt [kW] inverter process) can reduce barriers to PV installations. The Solar ABCs asked the North Carolina Solar Center (NCSC) and the Interstate Renewable Energy Council (IREC) to lead the review and development of suggested updates to the FERC SGIP screens and the 10 kW inverter process after conducting an interactive development process based on a questionnaire sent to small generator interconnection subject matter experts (SMEs).

Background

FERC issued the FERC SGIP procedures as a final rule in 2005 (Order 2006) (FERC, 2005), then clarified and refined the procedures in 2006. FERC developed the SGIP with extensive participation by utilities, regulators, renewable energy advocates, industry, and government experts. Through this process, FERC hoped to minimize the federal-state division and promote consistent, nationwide interconnection rules by adopting many of the best practices interconnection rules recommended by the National Association of Regulatory Utilities Commissioners (NARUC). Incorporated into the final FERC rule was the Small Generator Interconnection Agreement (SGIA). FERC issued the current versions of the SGIP and the SGIA as a final amended rule on August 28, 2006 (see Order 2006-B) (FERC 2006-B, 2005).

In summary, Order 2006 (et seq.) required all public utilities that own, control, or operate facilities under FERC's jurisdiction to file standard interconnection procedures (the SGIP) and a standard interconnection agreement (the SGIA) to interconnect generating facilities up to 20 megawatts (MW). The SGIP applies directly to large DG sources interconnecting to FERC jurisdictional lines or those making FERC jurisdictional sales of electricity. For interconnection of DG smaller than a few megawatts, which constitutes the vast majority of such interconnections, the FERC SGIP rarely applies as a result of current FERC recognition of state public utility commission jurisdictions. Small DG sources are usually interconnected to distribution lines rather than to transmission lines, and FERC's jurisdiction covers utility wholesale transmission lines. Thus FERC has only limited jurisdiction over the lower voltage distribution systems. However, according to FERC Order 2006, FERC may claim jurisdiction over a distribution line when a "non-qualifying facility" generator interconnects to a distribution line covered by a public utility's open access transmission tariff (OATT) to make wholesale sales of electricity (FERC 2006, 2005).

Unless they're very small, most utilities own or operate some FERC-jurisdictional utility lines. They are thus required to file interconnection procedures that follow the FERC SGIP as part of their OATT. Some utilities may seek similar requirements for distribution lines subject to state jurisdiction for the sake of procedural uniformity. However, to date, this rationale has not been strong enough to lead to widespread adoption of the FERC SGIP by states. State utility commissions and their NARUC traditionally defend their jurisdiction against encroachment by FERC and don't feel obligated to start with the FERC SGIP in developing their state interconnection procedures. Some states have essentially adopted the FERC SGIP for reasons of regulatory economy and other policy issues. Additionally, utilities (who are very often active and well-represented participants at state commissions) interested in limiting DG may have opportunities at the state level to seek more restrictive interconnection provisions than the FERC SGIP provides. As a result, although the FERC SGIP may have been intended to serve as a model for state utility commissions, as a practical matter the effect of the FERC SGIP as a model has been limited.

Connecting to the Grid is a monthly electronic newsletter published by IREC. *Connecting to the Grid* editor Laurel Varnado says the FERC SGIP screens have been adopted in a number of state and utility interconnection standards (personal communication, March 12, 2010). According to Varnado, Colorado and Connecticut based their interconnection procedures on the FERC SGIP model, and 14 states use FERC SGIP-based technical screens in their interconnection procedures. Further, the updates suggested in this report are largely based on positive experience with state-originated "best practices."

While the FERC SGIP screens aim to be neutral across different types of generation, the technical attributes of DG and the various types of electric power systems (EPS) have a bearing on interconnection requirements. For example, inverters can incorporate improved safety and faster operational features into their controls than is possible in synchronous generators. This provides for failsafe designs that prevent the inverter from operating unless its protective functions are working correctly. Properly designed and tested inverter-based devices require little (if any) additional external protection equipment for interconnection. The fact that inverters are inherently very "controllable" has contributed to their increased use in utility applications—from a few thousand systems in 2002 to more than 69,000 systems by the end of 2008 (IREC, 2009). Rotating generators (i.e. those powered by engines, wind, or hydropower), which pose more difficult technical questions and may use slower mechanical relays to accomplish interconnection, are treated differently in the codes and standards. They should also receive separate treatment in sections of the FERC SGIP, particularly as the differences in the technical issues and their impacts relating to interconnection are magnified by quickly increasing PV penetrations and advances in inverter technologies.

From a utility interconnection perspective, DG systems are generally classified by the type of generator[1] and the protective equipment that makes up the interface between the system and the grid. The classifications include solid-state or static inverters, induction machines, and synchronous machines (see Appendix I). Nearly all renewable energy systems are grid-tied PV systems that produce grid-quality alternating current (AC) power using an inverter, and typically are treated as similar even though the source of power may be different (solar photovoltaic and fuel cell, for example). High-speed microturbines and some wind turbines also use an inverter for interconnection despite the fact that they generate power through the rotation of a generator. This allows the generator to produce AC current at frequencies higher than the grid, with the power converted to direct current (DC) before being converted to grid compatible AC power by the inverter.

1 The IEEE 1547 technical standard uses the term "interconnected system" rather than "generator."

Overview of FERC SGIP Screens

The FERC SGIP contains the technical procedures that a small generator and utility must follow when connecting the generator to utility lines subject to FERC jurisdiction. The standards include provisions for three levels of interconnection based on generator size:

- The "10 kW Inverter Process" for certified,[2] inverter-based systems no larger than 10 kW[3]
- The "Fast Track Process" for certified systems no larger than 2 MW
- The default "Study Process" for systems no larger than 20 MW, including those that fail to pass the fast track screens (this study process is not included in this review).

The standards are embodied in a single set of ten screens for both the 10 kW Inverter Process and the Fast Track Process. Systems that pass all ten of the screens (some states and models use a subset of the 10 screens in the 10 kW Inverter Process) may interconnect without going through a more in-depth study process, which requires additional time and expense. The goal of these technical screens is to reduce resistance to adding new DG capacity by providing a quick and simple method to determine which DG systems can be safely interconnected with negligible risk of negatively impacting grid function. The FERC SGIP screens (§ 2.2.1) are summarized below:

2.2.1.1 The proposed Small Generating Facility's Point of Interconnection must be on a portion of the Transmission Provider's Distribution System that is subject to the Tariff. (Note: This screen is non-technical and is not reviewed in this report.)

2.2.1.2 If the interconnection is to a radial distribution circuit, the interconnection may not facilitate an increase in aggregated generation on the circuit that exceeds 15% of the line section annual peak load. A line section is a portion of an interconnected utility's electric system bounded by automatic sectionalizing devices or the end of a distribution line.

2.2.1.3 The interconnection of inverter-based generation may not facilitate an increase in aggregated inverter-based generation to the load side of spot network protectors that exceeds the smaller of 5% of a spot network's maximum load or 50 kW.

2.2.1.4 The interconnection may not contribute more than 10% to the distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of change of ownership.

2.2.1.5 The proposed interconnection may not cause any distribution protective devices and equipment or interconnection customer equipment to exceed 87.5% of the short circuit interrupting capability.

2.2.1.6 The proposed interconnection must use the correct type of interconnection (3-wire to 4-wire) to the primary distribution line given the type of electrical service provided to the interconnecting customer.

2.2.1.7 If the proposed generation is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary including the new generation may not exceed 20 kW.

2.2.1.8 If the proposed generation is single-phase and is to be interconnected on a center tap neutral of a 240-volt service, its addition may not create an imbalance between the two sides of the 240-volt service of more than 20% of the nameplate rating of the service transformer.

2 Certified refers to the certification requirements explained in Attachments 3 and 4 of the FERC SGIP, which may be found at www.ferc.gov/industries/electric/indus-act/gi/small-gen/procedures.doc

3 Available at http://www.ferc.gov/industries/electric/indus-act/gi/small-gen/procedures.doc

2.2.1.9 The proposed generation may not exceed 10 MW if interconnected to the transmission side of a substation transformer feeding the circuit in an area where there are known, or posted, transient stability limitations (three or four transmission busses from the point of interconnection, for example).

2.2.1.10 Construction would not be required by the utility. (Note: This screen is non-technical and is not reviewed in this report.)

The FERC SGIP screen 2.2.1.2 is of particular interest, because it typically limits the size and number of DG systems that can be interconnected quickly without going through the "Study Process." In other words, it is the screen most likely to be failed as PV systems reach higher penetrations. The technical reasons for the capacity limit are related to minimum daytime load on the line section, not peak load. Specifically, the aggregate DG must never be greater than the load on the line section. However, unlike peak load data, minimum load data is currently not uniformly available to utility planners. The 15% threshold of the peak load is therefore an estimate of 50% of the minimum load on a line section. For most distribution systems, a line section minimum load is in the range of 30% of the peak load. Thus, the 15% limit on aggregate generation capacity would represent only half the minimum load of the line section.

The U.S. Department of Energy's (DOE's) 2008 Renewable Systems Interconnection (RSI) studies attempted to address the 15% line section threshold level defined by Screen 2.2.1.2. These studies modeled some of the impacts of high penetration of grid-tied PV systems. One of the RSI reports on voltage support concludes, "In all the cases studied, PV inverters can positively contribute to the feeder voltage regulation and result in an improved voltage profile. At a high enough penetration, PV inverters may be able to provide feeder voltage support" (Renewable, 2008). However, none of the RSI studies addressed safety issues ("islanding") associated with the 15% line section threshold.

This screen was meant to flag interconnection applications that may impact distribution system operation, safety, or reliability—and thus prevent unintended islanding. In addition, inverter-based and rotating generators should probably receive separate treatment in the 15% screen. We were interested in the responses to the questions about the 15% screen from the California-based SMEs, because California has installed more than half of the grid-tied PV systems in the United States.

Status of Distributed Generation in 2010

In the FERC Order 2006 dated May 12, 2005, FERC stated they "believe that the thresholds used in the screens to be conservative and that there is negligible chance that a proposed interconnection could pass the screens and actually impact the safety and reliability of the Transmission Provider's electric system" (FERC, 2005). The need to update the small generator rules was foreseen in FERC's Final Rule, which stated that "beginning two years from the issuance of this order, [we will] consider and recommend consensus proposals for changes in the Commission's rules for small generator interconnections" (FERC Docket RM02-12-000, 2005). To our knowledge, the present study is the first review or proposal to update the FERC SGIP screens.

Currently, interconnection rules in the United States are based upon submissive contribution of grid-tied PV systems. These standards were, of course, originally developed when there was a very low level of penetration of grid-tied PV systems, and even less documented experience. Now is the time to updated regulatory rules like FERC SGIP based on the decade of experience since these rules were codified. Updated rules based on these experiences may avoid the time delays and expense of unnecessary interconnection system impact studies, prevent regulatory lag, and enforce the replacement of fossil fuel and imported oil—all while maintaing reliability and safety.

The fact that the economics of PV systems are believed to be approaching grid parity (Denholm, Margolis, Ong, & Roberts, 2009) heightens the need for regulatory update.

The solar industry has steadily reduced the costs of PV DG systems during the past 10 years, and prices for conventional forms of electricity are likely to rise—perhaps substantially—in the coming decade. These trends are almost certain to dramatically increase the penetration of grid-tied PV systems, so it is imperative to prepare for this opportunity by developing regulatory procedures that maximize the contribution of PV systems to the electric power system. In addition to reducing prices, inverter and grid technologies are rapidly advancing, which could enable inverter-based DG to provide additional value such as providing voltage and volt-ampere reactive (var) support[4]. These movements need to be considered when updating interconnection standards.

Methodology

The goal of this project was to gather the opinions of SMEs who work in the field of small generator interconnections. We used an internet-based questionnaire for this purpose. We developed the questionnaire, as well as the list of SMEs, with input from energy professionals from across the country who participated in two stakeholder planning meetings before we distributed the questionnaire.

More than 200 people attended the first stakeholder meeting, held October 30, 2009, at the Solar Power International conference in Anaheim, California. At the subsequent stakeholder planning meeting, conducted online via GoToWebinar software on December 2, 2009, we presented more details about the scope of the study and described the voter's pamphlet approach[5] that we used to develop the SME questionnaire. Twenty-six people registered for this second meeting. We sent invitations to these meetings to a comprehensive list of Solar ABCs and IREC contacts. Each meeting began with a presentation by one or both of us addressing the basis for the study and the method for conducting the questionnaire. We used any resulting questions and comments to refine the study procedures and questionnaire itself. For example, when attendees questioned the confidentiality of SME responses, we created a confidentiality policy with an option for SMEs to opt out of publicizing their comments. Reaching out to the stakeholders resulted in five additional requests to participate in the questionnaire.

Previous studies have noted a gap between researchers' practical expertise in survey design and familiarity with the questionnaire's topic (Ramirez, 2002). We are experts in the field, and we avoided this problem by designing the questionnaire ourselves with input from other SMEs. This ensured an in-depth understanding of the topic, which is essential in questionnaires requesting complex or technical information. As a result, the FERC SGIP questionnaire was carefully constructed to elicit insightful ideas and opinions from the respondents. We chose a popular online questionnaire tool (Survey Monkey) to collect the SME responses. Major advantages of the online approach include cost-effectiveness and speed. A limitation is demographic—younger people are more likely to respond to online questionnaires (Ramierez).

To begin the process, we asked the SMEs to examine eight technical FERC SGIP screens. We then questioned them about the need to raise the threshold for the simplified interconnection process for inverter-based systems above the current 10 kW limit. We also provided SMEs several references and links to reports, such as the 15 RSI studies (Kroposki et al., 2008).

Prior to the questions about each screen, the questionnaire provided the SMEs a summary of the screen, arguments for updating the screen, and arguments for leaving

4 Voltage and var support are services that enhance grid stability and reliability. Voltage support is service that may be provided by certain devices to slightly adjust the voltage at that location on the grid to keep it within the required range. Var support is a similar service to adjust the amount of reactive power at that location on the grid. Volt-amperes reactive (var) is a unit used to measure reactive power in an AC electric power system.

5 The voter's pamphlet approach is to present both sides of an issue in an unbiased way, with supporting references when possible.

the screen unchanged (see Appendix III). We asked the following questions about each screen:

- Do you support updating this screen? (Response options were Yes, No, or Can't answer because ___.)
- If you support updating this screen, what change would you recommend? (One to five possible screen updates were presented in multiple choice fashion, including the option to write in a suggestion.)
- Please briefly provide an explanation of your position.

SMEs were required to reply to the first question, but the following two questions were optional. In general, everyone who responded "yes" to question 1 also answered question 2, and the vast majority of SMEs also responded to question 3 for each screen. At the end of the questionnaire, the SMEs were asked about their role and experience with DG interconnection.

The questionnaire was then sent to the following SMEs:

- All Members of IEEE 1547.6 Power System Distribution Secondary Networks Working Group
- All Members of IEEE 1547.7 Distribution Impact Studies Working Group
- Eight additional individuals identified by Solar ABCs (two national labs, two utilities, two consultants, and two PV industry).

The SMEs who responded to the questionnaire were a good balance between utility engineers and consultants (see Figure 2). We specifically avoided extending the invitation to complete the questionnaire to trade groups and special interest entities.

Following the collection of the SME questionnaire responses, we held a third stakeholder meeting to present the results. We focused on the issues upon which the SMEs reached a consensus, because these are the issues likely to be recommended for updating. We considered a consensus to be agreement of at least two-thirds of the SMEs. This meeting was held via GoToWebinar software on April 14, 2010, with 113 people registered. Like the other stakeholder meetings, we began with a presentation that addressed not only the results of the voting on the *Do you support updating this screen?* question on each of the issues, but also a brief discussion on the plan for the report. Based on analysis of the questionnaire results and review of recent studies on PV interconnection, and in consultation with other SMEs, we developed recommendations for updating the existing FERC SGIP screens.

Results and Recommendations

Table 1 lists the SMEs receiving the questionnaire and responding to it:

Table 1: Target SMEs

Target SMEs	Questionnaire Recipients	Number of SMEs Completing Questionnaire
IEEE 1547.7 Working Group Only	91	23
IEEE 1547.6 Working Group Only	35	5
Both IEEE 1547.6 and 1547.7 Working Groups	20	7
Solar ABCs Invites	8	2

When we reviewed the responses, we found that roughly two-thirds or more of the SMEs (considered a consensus for the sake of this report) recommended an update of only three of the FERC SGIP screens. Based on this and input from other studies, we recommend that all three of these screens be strongly considered for updating. We also recommend that a fourth very important screen (Screen 2.2.1.2) be aggressively studied to determine how its penetration limit may be increased so that it does not create an unnecessary barrier to PV development or lead to safety or reliability problems. For similar reasons, we suggest studying the size limit of the 10 kW inverter process to determine the appropriateness of increasing it. A discussion of the SME questionnaire responses about these four screens and the 10 kW inverter process is below. Detailed response results of the entire questionnaire are available in Appendix II.

Screen 2.2.1.7: *The existing screen is: "If the proposed Small Generating Facility is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed Small Generating Facility, shall not exceed 20 kW."*

The vote on this screen was 26 for an update versus 6 against, thus showing the strongest support for change of any screen. The change supported by the majority of the SMEs was to base the screen on a percentage of the transformer nameplate power rating instead of a static system size. The comments in favor of an update include, "I do not clearly understand the technical basis of the FERC 20 kW limit. I personally prefer the limit to be based on service transformer nameplate capacity." SMEs opposed to changing this screen said, "Actually, the aggregate capacity of DG installed on a shared secondary should be limited to 10 kW. Simply because there are two customers on a single secondary does not mean that you can safely double the capacity limit of 10 kW. Although the 65% rule applied to a 15 kV transformer limits the aggregate capacity to 10 kW, applying the rule to larger transformer allows the customer to bypass the capacity rules by installing/requesting a larger transformer. As far as safety, I am leaning slightly towards allowing the 65% transformer capacity rule if each customer is constrained to a maximum of 10 kW. Therefore, I am unable to support the change."

There is also a precedent for changing this screen to a percentage of the service transformer nameplate power capacity basis set by New Mexico. Their small generator interconnection procedures have the following screen: "If the proposed Generating Facility is to be interconnected on a single-phase Shared Secondary, the aggregate Generating Facility capacity on the Shared Secondary, including the proposed Generating Facility, shall not exceed 65% of the transformer nameplate rating." Due to the strong SME support in the questionnaire responses and the New Mexico precedent, we

recommend that the FERC SGIP screen on shared secondary be updated to a limit based on service transformer nameplate power capacity.

Screen 2.2.1.9: *The existing screen is: "The Small Generating Facility, in aggregate with other generation interconnected to the transmission side of a substation transformer feeding the circuit where the Small Generating Facility proposes to interconnect shall not exceed 10 MW in an area where there are known, or posted, transient stability limitations to generating units located in the general electrical vicinity (three or four transmission busses from the point of interconnection, for example)."*

This screen received the second highest number of votes for change—24 voted to change it, nine wanted it to remain the same. Comments ranged from "Utility distribution engineers do not know how to address the screen as it is written now" to "The trouble is, a 10 MW [system] can represent a significant amount of generation depending upon the transmission or sub-transmission to which it is connected. This is particularly true in rural systems. The loss of 10 MW of generation could be significant and result in voltage stability problems. FERC and NERC [North American Electric Reliability Corporation] regulations of stability do not apply [to] voltage levels below 100 kV. Therefore, any change to increase the aggregate capacity above 10 MW should be, at a minimum, tied to system voltage." We believe that this screen is vague and thus frequently misunderstood by SMEs, so it should be changed to address specific safety or reliability concerns.

Screen 2.2.1.3: *The existing screen is: "For interconnection of a proposed Small Generating Facility to the load side of spot network protectors, the proposed Small Generating Facility must utilize an inverter-based equipment package and, together with the aggregated other inverter-based generation, shall not exceed the smaller of 5% of a spot network's maximum load or 50 kW."*

The networks screen vote results were 21 for updating, 11 against, effectively meeting the two-thirds consensus threshold.

We believe this screen needs two updates. First, FERC SGIP screen 2.2.1.3 should expand its narrow focus on spot networks, which typically serve one large building, to also address area network interconnections[6] (FERC Docket RM02-12-000, 2005) that may supply several city blocks. Second, the limit should be raised in accordance with new rules adopted at the state level. Specifically, the state of Connecticut drafted a rule on networks stating, "Total aggregate generation interconnected to an area network will be limited to 3% of the maximum network transformer connected kVA with the feeder supplying the largest number of network units out of service, or a maximum of 500 kW, whichever is less" (Connecticut, 2010). It should be noted that this Connecticut rule also defines some additional technical criteria, which cannot be overlooked, but does not change the significance of this 3% or 500 kW rule.

Additionally, Consolidated Edison of New York, Inc. (Con Ed), in an effort to reduce barriers to interconnection of customer-owned DG, announced that inverter-based systems sized between 25 kW and 200 kW may follow the expedited application process for interconnection to the utility's distribution network systems as long as the inverter-based system has been certified and tested in accordance with UL 1741 (November 2005 revision) and the utility has approved the project accordingly. While the Con Ed networks in New York represent the majority of the area networks in the United States, they are not necessarily representative of all U.S. area networks.

6 Network system means an AC power distribution system in which customers are served from three-phase, four-wire low-voltage circuits supplied by two or more network transformers whose low-voltage terminals are connected to the low-voltage circuits through network protectors. The network system has more than two high-voltage primary feeders, with each primary feeder typically supplying multiple network transformers, depending on network size and design.

Furthermore, the IEEE 1547.6, "Recommended Practice for Interconnecting Distributed Resources with Electric Power Systems Distribution Secondary Networks," had gone to ballot at the time of this writing (July 2010). When released, the results of this guideline should also be considered when deciding on a possible update to screen 2.2.1.3.

Screen 2.2.1.2 *The existing screen is: "For interconnection of a proposed Small Generating Facility to a radial distribution circuit, the aggregated generation, including the Small Generating Facility, on the circuit shall not exceed 15% of the line section peak load as most recently measured at the substation. A line section is that portion of a Transmission Provider's electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line."*

The votes to update this screen were split—18 in favor, 20 opposed. An SME's comment in favor was, "I believe that the majority of the interconnections of (aggregate) gens sized between 15% to 30% of peak load will cause no additional issues, but there may be a few where genuine concerns should be addressed. The key is to have a simple supplemental review process with secondary screens to quickly address the question." An SME concerned about the change wrote, "I think increasing the limit ultimately would be OK if a study focused on min/max loading ratios, time of day aspects, etc., that demonstrates the 15% number is predominantly too conservative an estimate of daytime low load conditions."

More than half of the interconnected grid-tied PV systems installed in the United States are installed in California. As expected, some of the highest levels of grid-tied PV penetration are also in California. We were interested in responses from California-based SMEs, given their level of experience with a 15% threshold. Of the respondents with California DG interconnection experience, ten support updating the screen and seven do not. Of the ten SMEs supporting an update, nearly two-thirds voted to increase the limit to 30% of line section peak load, which is double the current limit.

The nearly even split in opinion among all the SMEs contrasts with the more favorable response from the California SMEs. Many of the SMEs who voted against raising the limit cited safe operations (islanding) as the issue. Low limits in the screen tend to burden the PV industry with the cost and time delay of system studies. On the other hand, setting the level higher than necessary increases risk and may lead to grid problems, inviting potential backlash that could damage any progress being made in adopting PV. However, raising the limit is vital for continued rapid growth in PV, so it is prudent to determine the appropriate limit. Many SMEs providing input—as well as authors of recent research reports—believe the safe limit is significantly higher than the current 15% limit in this screen. Therefore, we recommend that DOE or NREL develop a study to address the concerns identified by the SMEs and to determine the procedures and limits that will preserve safety and reliability without hampering PV development. One facet of the solution may be to treat inverter-based generators separately from other generators.

10 kW Inverter Process: *"The procedure for evaluating an Interconnection Request for a certified inverter-based Small Generating Facility no larger than 10 kW that uses the section 2 screens. The application process uses an all-in-one document that includes a simplified Interconnection Request, simplified procedures, and a brief set of terms and conditions. See SGIP Attachment 5."*

The votes in favor of updating this screen were 21 votes for and 16 against. While these numbers do not reflect a two-thirds majority threshold, we felt that several SMEs who supported an update made strong arguments in favor of it and the

arguments made for keeping the existing screen were weaker. For example, one SME with a strong argument explained his support of an update like this, "I favor the increase to 25 kW because of the precedent (in New York, for example), the lack of issues that have arisen from sizes in this range, and most importantly, because the systems still have to pass the fast-track screens. This should adequately protect against systems being installed without proper scrutiny." It should be noted that more than 75% of the SMEs who support increasing the size limit indicated they would support moving the limit to 25 kW or higher.

Even though 16 SMEs did not support updating the screen, their comments shed light on the fact that more dialogue is necessary before a final decision about updating this screen is made. We believe that many of the SMEs who voted against updating this screen may be convinced of the appropriateness of the update if there is an opportunity for open dialogue among SMEs about this screen. For example, one SME said, "Standards such as [Underwriters Laboratories] UL/IEEE/NEC [National Electrical Code] do not address multiple DR [distributed resources]. Twenty-five kW DR, in aggregate, could very quickly cause problems on distribution secondaries," which suggests that this SME did not consider that to be eligible for the 10 kW Inverter Process a system must pass all 10 fast track screens.

Several states (New York and Connecticut, for example) recently adopted small generator interconnection procedures that have a 25 kW system size limit on the streamlined inverter process. Additionally, IREC's model small generator interconnection procedures, which represent best practices, contain a 25 kW limit to its streamlined inverter process, referred to as the Level I process. These procedures were developed more recently than the FERC SGIP, thus allowing IREC to consider recent industry experience with significantly more distributed PV systems than during the development of the FERC procedures.

Considering the responses of the SMEs and the precedents set by the recent state and model small generator interconnection procedures, we believe there is considerable justification to increase the inverter process system size. Despite the lack of a two-thirds majority for updating the screen, but due to the positive responses from many of the SMEs, a lack of issues with systems this size, and the recent precedents set by state and model small generator interconnection procedures, we believe FERC and NARUC should facilitate additional dialogue on the issue and consider increasing the system size limit for the Inverter Process.

Other Screens

For the remaining screens, no consensus was reached by the SMEs. They were mixed about their support of updating those screens, and many mentioned serious concerns regarding both the current versions and the considered updates of these screens. We believe that the process to address issues and concerns in the remaining screens requires additional interactive discussion that is beyond the scope of this report.

Competitive Fairness

Recommendations related to competitive fairness are presented in the following section.

Summary of Recommendations

The Solar ABCs commissioned this study to analyze and suggest updates to the FERC SGIP screens. The goal was to review the lessons learned in federal and state proceedings since the adoption of the FERC screens in order to determine the feasibility of further simplifying interconnection procedures, and, perhaps, moving the federal screens closer to the converging "best practice" state screens, thereby reducing barriers to installing PV equipment.

Thirty-seven subject matter experts responded to an online questionnaire and provided recommendations concerning the technical FERC SGIP screens and the 10 kW Inverter Process. As a result, we recommend that three screens be updated, and that a fourth screen and the 10 kW Inverter Process be studied or discussed further. We discerned no consensus with respect to the remaining screens.

We recommend the following changes:

Screen 2.2.1.7: The limit placed on the size of the aggregate generation on a single phase shared secondary should be updated to be in terms of a percentage of the transformer nameplate power rating.

Screen 2.2.1.9: The stability requirement should be rewritten for clarity.

Screen 2.2.1.3: Area networks should be covered in addition to spot networks. In addition, limits on maximum load should also be revised upward in keeping with recent rules enacted in Connecticut and by Consolidated Edison in New York and with the guidelines defined in IEEE 1547.6, which went to ballot in mid-June 2010.

Screen 2.2.1.2: Further investigation and research is needed to determine whether to increase (and if so, by how much) the current 15% limit on generating capacity related to circuit peak load (or possibly changing the limit to a percentage of the circuit minimum load). Separate treatment of inverter-based generation should be considered. DOE or NREL should aggressively study these issues.

10 kW inverter process: Further dialogue and investigation is needed to determine whether to increase the limit from 10 kW for the simplified inverter interconnection process (and if so, by how much).

The Solar ABCs recommends that FERC and NARUC collaborate to further determine the potential benefits of updating these FERC SGIP screens. The goals are to remove barriers to increased PV penetration and harmonize state and federal approaches to the screens based on what has been learned over the past decade. The current FERC–NARUC collaborative on demand response provides a suitable template for a joint effort on the FERC SGIP screen update.

Competitive Fairness

Prior to February 2008, utilities were not eligible to receive the 30% investment tax credit (ITC) for PV. When the law was amended to extend the ITC to investor owned utilities (IOUs), it resulted in a dramatic increase in utility solar installations. According to IREC's Larry Sherwood, the installations could increase from 22 MW in 2008 to more than 300 MW projected in 2010 (personal communication, April 22, 2010). IOU access to the ITC has profoundly altered the utility role in the PV market. However, this is not a complete blessing. Allowing access to the ITC by IOUs subjects the marketplace to an increased potential for conflicts of interest—when the utility directly competes with nonutility competitors who need the utility's interconnection, for example. The utility's business interest for promoting its own PV installations presents a clear conflict with its role as aggregator and interpreter of study information, federal and state regulations, and industry guidelines for PV installations. Based on previous situations, it cannot be assumed that utilities will keep the public's best interest in mind. Rather, without clear

direction from regulators, utilities might discriminate against competitors to maximize shareholder value.

Anecdotal problem reports are abundant. For example, the authors know of a situation in which a utility installed a 3.7 MW synchronous generator on its system without a transfer trip or three-phase circuit breaker, even though it consistently requires both pieces of equipment for interconnection of customer-owned facilities. The cost savings evident in the discriminatory requirements give the utility a significant advantage. This denies the public the benefit of a real market, and allows the beneficiary of a state-granted monopoly to use its monopoly power for its own gain.

Fair-trade practices require utility-owned PV and non-utility-owned PV providers to follow the same rules, often known as anti-discrimination. Therefore, the Solar ABCs recommends that FERC and NARUC be vigilant in ensuring that utilities follow the same procedures that are imposed on other generators. This might be achieved by jointly developing an enforceable non-discrimination policy or rule to ensure uniform application of the technical requirements of all DG systems, regardless of whether they are utility-owned.

Acronyms

AC	alternating current
Con Ed	Consolidated Edison
DC	direct current
DG	distributed generation
DOE	U.S. Department of Energy
EPS	electric power systems
FERC	Federal Energy Regulatory Commission
IEEE	Institute of Electrical and Electronics Engineers
IREC	Interstate Renewable Energy Council
ITC	investment tax credit
IOU	investor owned utilities
kV	kilovolt
kVA	kilovolt-ampere
kW	kilowatt
MW	megawatt
NARUC	National Association of Regulatory Utility Commissioners
NEC	National Electrical Code
NREL	National Renewable Energy Laboratory
NCSC	North Carolina Solar Center
OATT	open access transmission tariff
PV	photovoltaic
RSI	renewable systems interconnection
SGIA	Small Generator Interconnection Agreement
SGIP	Small Generator Interconnection Procedures
Solar ABCs	Solar America Board for Codes and Standards
SME	subject matter expert
UL	Underwriters Laboratories
var	volt-ampere reactive

Glossary

Distributed generation—electricity generation defined by small-scale electricity generators (typically in the range of 3 kW to 10 MW) located at or near the end user, this method serves as an alternative to traditional electric power generation from large central plants. Each small generator may be interconnected with a local utility company's distribution system or not and it may be owned and operated by a customer, a utility, or a non-utility company.

Grid parity—the condition of the cost of electricity from a non-traditional source (e.g. solar photovoltaics) being equal or less than the cost of electricity provided by the local electric grid from an electric utility

Grid-tied—the state of being connected to the electricity grid, in contrast to being "off–grid" or "standalone" which indicates no connection to the electricity grid

Inverter—an electronic device used to convert direct current (DC) electricity into alternating current (AC) electricity. Such a device is required to allow a solar photovoltaic system, which generates DC electricity, to interconnect to the electricity grid, which uses AC electricity.

Islanding—a situation in which a portion of the electrical grid that contains loads and generation source(s) remains energized even after it is isolated from the rest of the electrical grid. A portion of the distribution system that does not shut down during a general grid outage as a result of local distributed generation resources continuing to power it would be an unintentional island.

Peak load—the maximum electric load (measured in kW or MW) experienced over a given period of time

Screen—a test or criterion used to determine if the given electric generator is eligible for a particular interconnection process

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Appendix I: DG System Types and Characteristics (IREC, 2009)

	Inverter	Induction Machine	Synchronous Machine
General Characteristics	Commonly current source-like (strictly, voltage regulated, current controlled) in grid-tied mode; voltage source in stand-alone mode, sometimes within the same unit. Low inertia (capable of very high-speed response).	Inherently current source; can be made to act as voltage source with external excitation. High inertia (relatively slow response).	Voltage source. High inertia.
Fault-Current Capabilities	Low (typically <1.2X normal current).	Medium (6X normal current).	High (10X normal current).
Power Quality	Total harmonic distortion and DC injection must be controlled; controllable power factor.	Low total harmonic distortion; power factor must be corrected.	Low total harmonic distortion; controllable power factor.
Examples	Fuel cells, PV, microturbines, some wind turbines	Some wind turbines, CHP	Solar thermal electric, diesel generators, traditional utility generators

Appendix II: Detailed Results of Questionnaire

Responding SMEs

Of the 154 SMEs who received a request to complete the questionnaire, 37 individuals, or 24%, completed it.

	Number of Individuals to Whom Questionnaire Was Sent	Number of Individuals Who Completed Questionnaire
IEEE 1547.7 Working Group only	91	23
IEEE 1547.6 Working Group only	35	5
Both IEEE P1547.6 and P1547.& Working Group	20	7
DOE/Solar ABC invites	8	2

Figure 1: Responding SMEs by Invitation Class

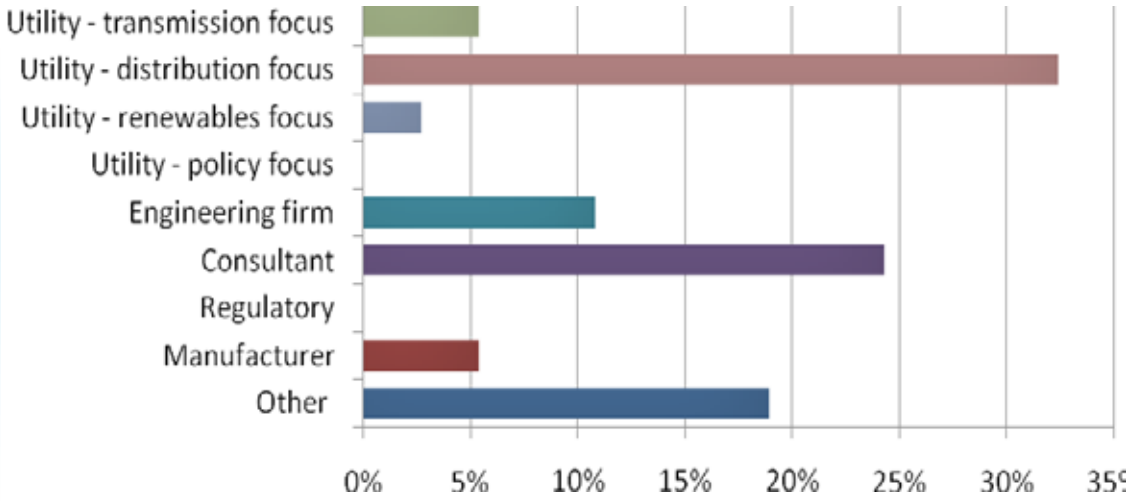

Figure 2: Current Role of SMEs Who Completed the Questionnaire

The categories presented in Figure 2 are the categories used in the questionnaire. The SMEs who answered this question with "Other" include four SMEs from government/ national labs, two from utilities, and one from a renewable energy nonprofit.

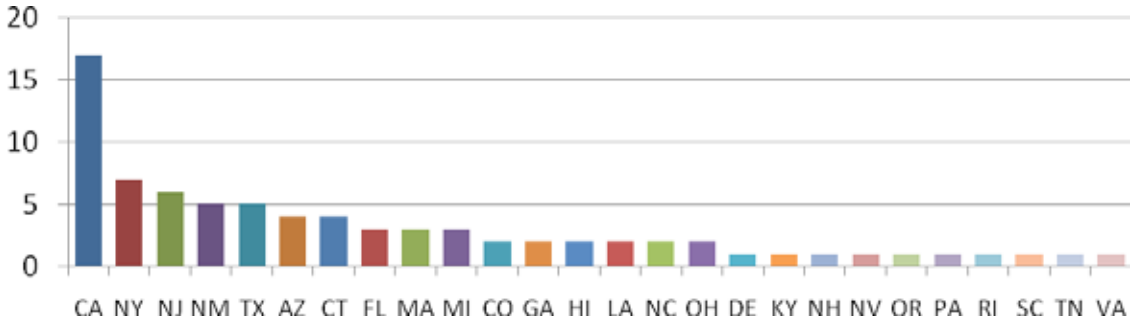

Figure 3: SME Response to: "In Which State or States has the Bulk of Your Recent Renewables Related Interconnection Work Been Focused?"

(31 of 37 Individuals Responded)

Quantitative Results

The first FERC SGIP-related question on the questionnaire was regarding the 10 KW Inverter Process. We sought to determine whether the SMEs agreed that the size limit of this process should be increased. The following are the results of the questions regarding the 10 KW Inverter Process.

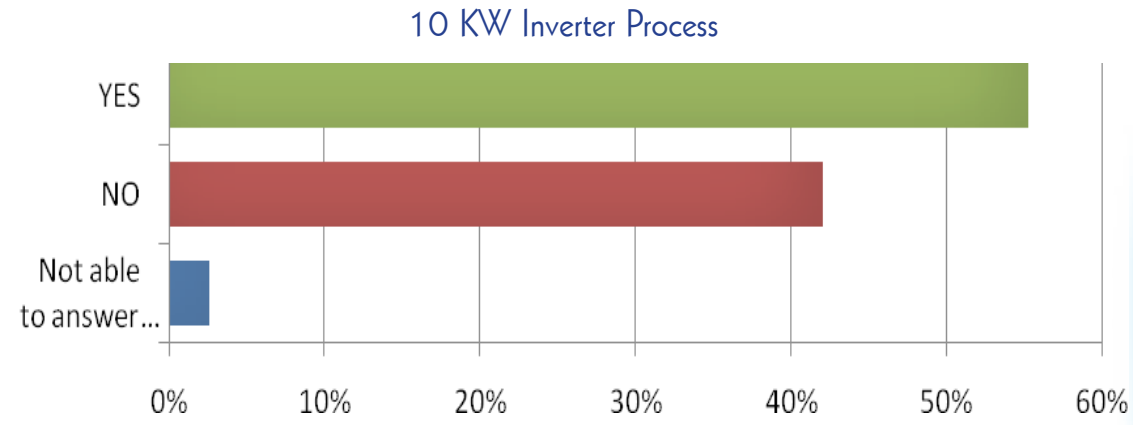

Figure 4: SME Response to: "Do You Support Updating the Size Limit for the Simplified Process for Small Inverter-Based Systems, Currently Known as the '10 kW Inverter Process'?"

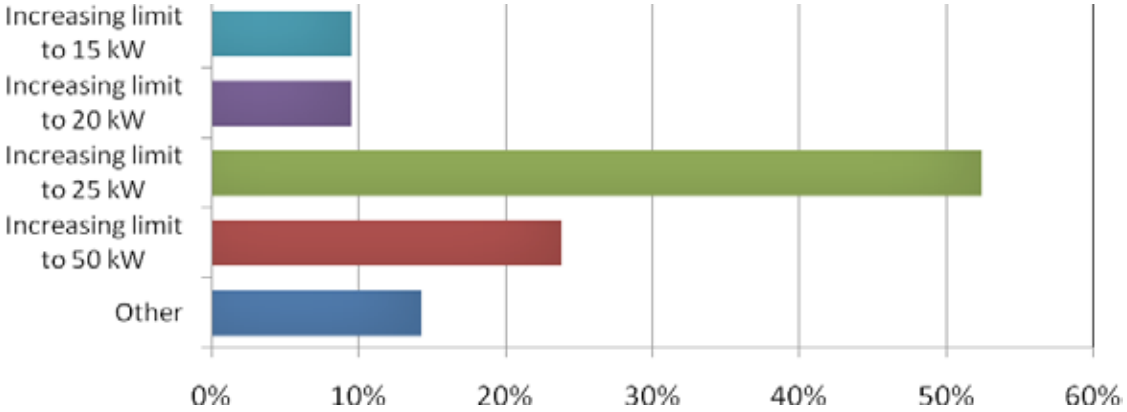

Figure 5: SME Response to: "If You Support Updating this Size Limit, What Change Would you Recommend?"

The updates suggested by SMEs who chose the "Other" option included "10 kW single phase and/or 30 kW total three phase." The SME explanations of their positions included comments such as:

> "I favor the increase to 25 kW because of the precedent (in NY for example), the lack of issues that have arisen from sizes in this range, and most importantly, because the systems still have to pass the fast-track screens. This should adequately protect against systems being installed without proper scrutiny."
>
> "This modest increase is warranted because the industry has acquired substantial experience since the original 10kW threshold was established. A 25kW level will likely find greater acceptance in the small commercial sector."
>
> "The total or aggregate impact of multiple installations at high penetration levels on certain feeders may have unforeseen negative consequences for reliability."

Some SMEs who voted that they would not support an increase in this size limit provided reasons, such as the third comment above, that are addressed by the fast track screens.

Screen 2: Aggregate Generating Capacity Versus Line Section Peak Load (15% Limit)

The first FERC SGIP screen addressed in the questionnaire was screen #2, which addresses aggregate generating capacity versus line section peak load. The existing screen sets a limit of 15% of the line section peak load for the aggregated generation on a radial distribution circuit. The following is a summary of the results of the three questions in the questionnaire regarding this screen, and one additional question that we asked only about this screen regarding the wording of the screen.

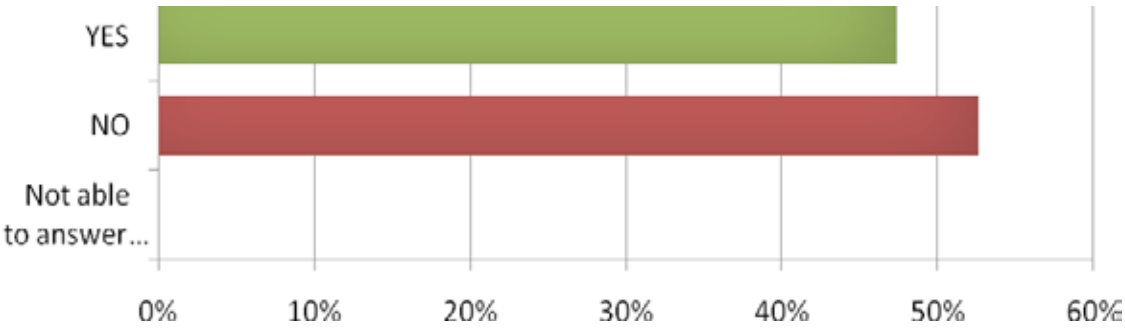

Figure 6: SME Response to: "Do You Support Updating Screen #2?"

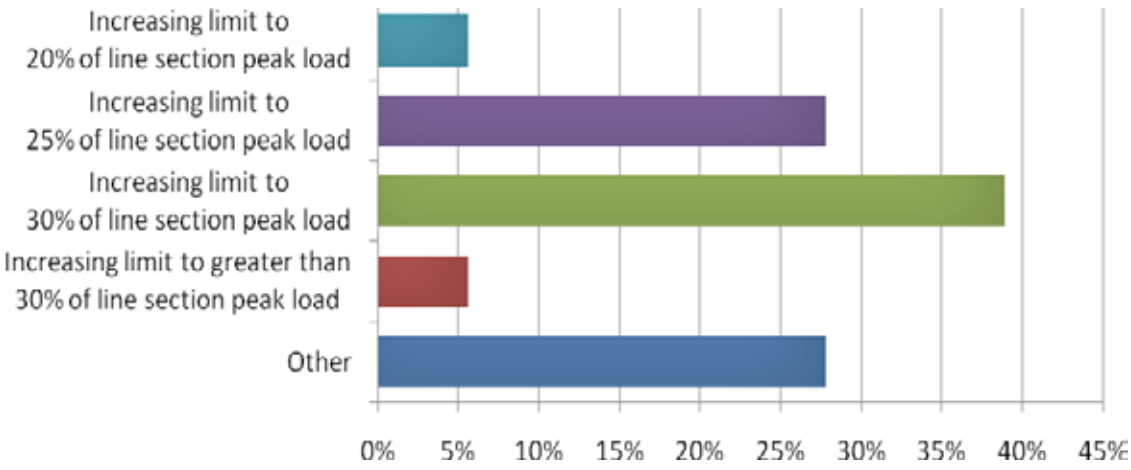

Figure 7: SMEs Response to: "If You Support Updating this Size Limit, What Change Would You Recommend? (Screen #2)"

In addition to the possible updates provided as answer choices, several SMEs wrote in other suggested updates. These suggestions ranged from "It should be based on the time duration of section peak load" to "Base on minimum load." Some examples of SME explanations of their position on this issue are shown below.

> "15% is a reasonable limit for a screening test. It is clear that penetration levels higher than this can be accommodated, DEPENDING on the characteristics of the circuit, other loads, diversity of generators, etc. The distributed voltage control incorporated into the inverters (see previous question) would also be a factor in changing this limit."

> "The 15% criteria is an intentionally conservative criteria. Not enough is known to make a blanket statement on acceptable limits vs. peak load; more study is needed. If a less conservative criteria is desired, I would prefer a criteria based on minimum load."

"In practice, peak solar output does not coincide with the circuit peak load. Peak solar project output typically occurs from mid-morning to mid-afternoon in the summer, while the circuit peak demand occurs as early as 14:00 hours and as late as 22:00 hours. Due in large part to this non-coincidence, actual solar generation impact on the host distribution circuit is generally less than the solar generator capacity alone would suggest. Therefore, increasing the limit to greater than 30% of line section peak load is possible without complications. [CSI Final 07-08 Impact Report]"

"None of the arguments for increasing the 15% screen addresses the issues of possible voltage rise, operation reliability and flexibility, protection issues etc. At this point we do not have enough experience and knowledge of generation connected to the distribution system to determine if the 15% can be increased. In two-three years, we may [have] gained additional information to allow us to evaluate this screen one more time."

"We track minimum as well as maximum load and it is at minimum load that generation becomes a problem, not at maximum load, some circuits 15% is too high, others it could be 35%, but in all cases there could be a single standard based on minimum load."

We asked the SMEs one additional question, about the wording of the comparison made in the screen. We asked if they believed the relevant comparison was correct as stated in the current screen, "aggregate generation on the circuit vs. line section peak load," or if they felt the following was a more correct way to state the comparison, "line section generation vs. line section peak load." Based on the responses, no change is recommended. The results are shown in the figure below.

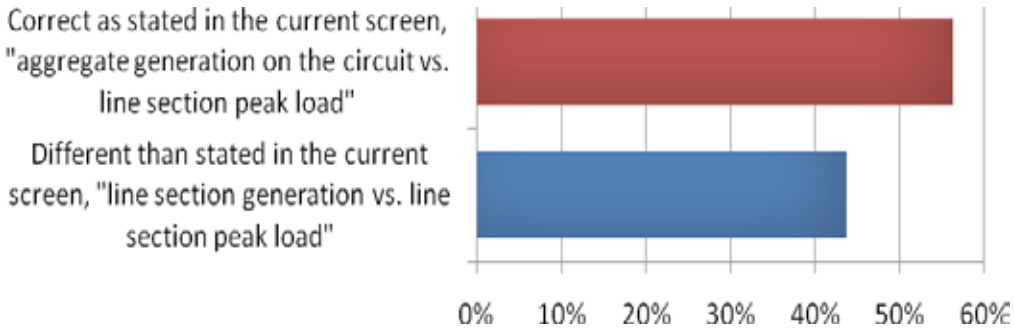

Figure 8: SME Response to Proper Wording of the Comparison Made in Screen #2

Screen 3: Network Protectors (Shall Not Exceed the Smaller of 5% of a Spot Network's Maximum Load or 50 kW)

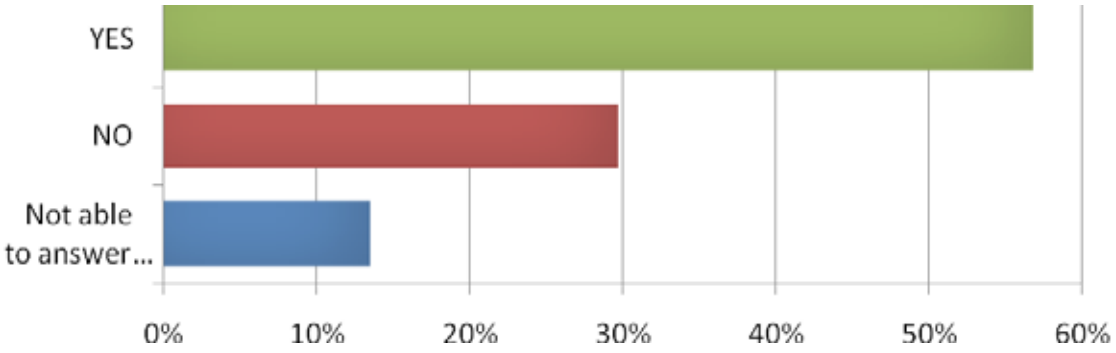

Figure 9: SME Response to: "Do you Support Updating Screen #3?"

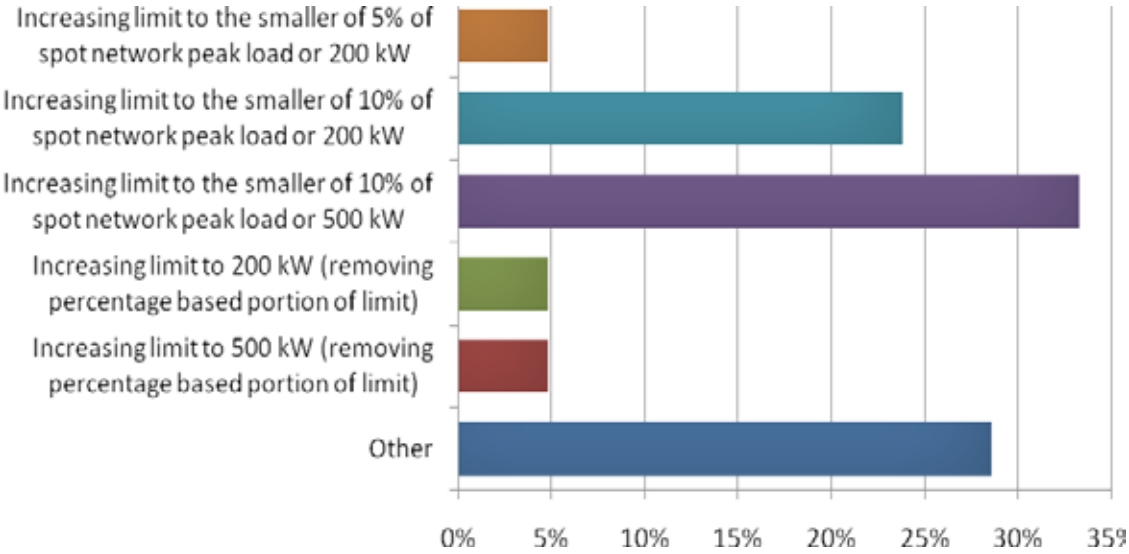

Figure 10: SME Response to: "If You Support Updating this Size Limit, What Change Would You Recommend? (Screen #3)"

More than 25% of the SMEs who responded that they would support updating screen #3 did not select one of the possible updates included in the second question about this screen. The most common suggestion was to tie the size limit to the minimum load instead of the peak load. Other responses included, "Wait for IEEE P1547.6 to become a published guide" and "[Set the] limits by category."

The SMEs provided a range of explanations for their positions both for and against updating this screen. Here are some representative comments:

> "I think there is ample evidence from the work in NJ and NY that the limits can be changed, but there are nuances between the different networks (spot, area, secondary) which should be defined, and possibly have different limits for each type."
>
> "New York is a unique circumstance having very dense load demand. It is prudent to keep this limit until substantially more experience is gained in other geographic areas. Notwithstanding this comment, any EPS operator is free to set their own limits much as Con Ed does."

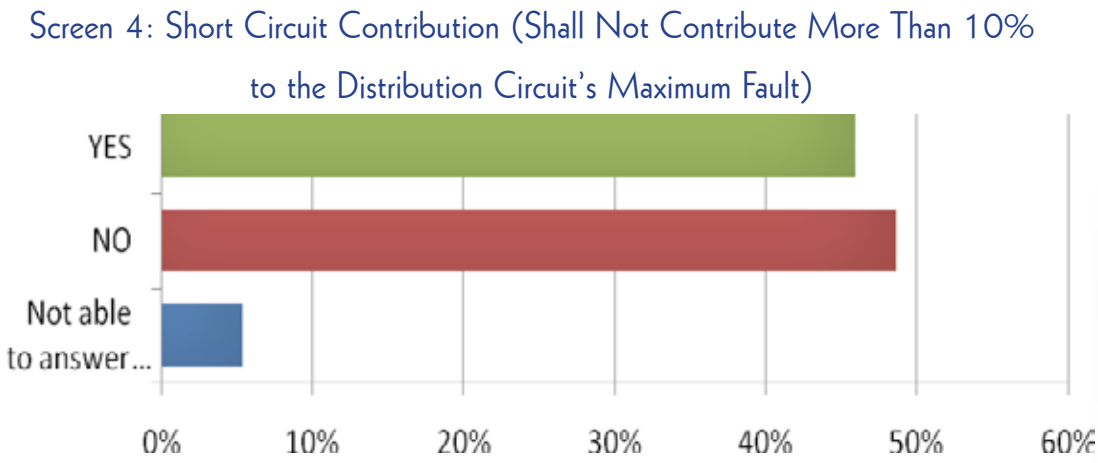

Figure 11: SME Response to: "Do You Support Updating Screen #4?"

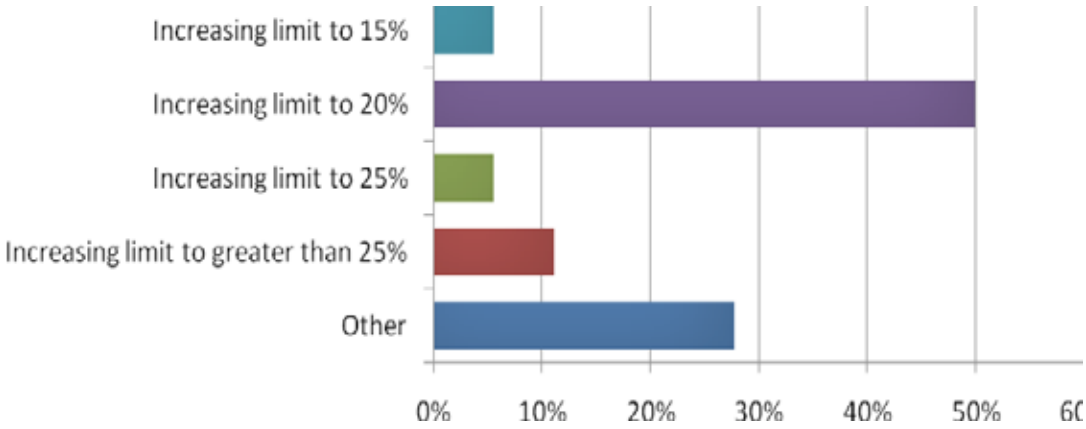

Figure 12: SME Response to: "If You Support Updating this Size Limit, What Change Would You Recommend? (Screen #4)"

Of the SMEs who support updating this screen, more than one quarter of them chose to write in a suggested screen update. Most of the write-in comments suggested associating a time duration to the current limit in one way or another.

The SMEs' explanations of their positions are represented by this selection of responses:

> "The industry standard of using 2x rated current for the short-circuit value overstates the sustained (momentary) fault current capability of the PV inverter. The actual fault current is closer to 1-1.2 pu after a few cycles and up to the point where a voltage or frequency element is tripped. If the 2x I-nominal will continue to be used, increasing the limit to 20% should have no consequential impact on the grid."

> "The argument made for changing the screen is that meeting this screen is not a problem for inverter-based units. So why not leave it in?"

> "Again, since this is only a screen, it would require that there be additional studies done if a project exceeds the screen. I am more comfortable with leaving this in place, as the ultimate result of high DG penetration is still an open question, and since system reliability is a very high measure for utilities, we would not want to see future problems in this regard that would require short circuit duty upgrades to both utility and customer switchgear and breakers because we were not staying on top of this issue."

> "Inverter-based devices cannot supply fault current for more than a fraction of a cycle. The problem is not the fault current magnitude, but the location of the current

source. New protection methods must be developed so that inverter-based sources can be rapidly interrupted in the event of high impedance, low current faults on distribution circuits."

"Fault current contribution from DG can be significant depending upon location and characteristics of the distribution feeder to which it is connected. A worst case scenario, which happens to be common place for DG locations, is when DG is located at the extreme ends of long, distribution feeders. Coordination becomes difficult: Protective switchgear settings set to DG fault current levels will be insensitive to traditional distribution/load faults. In this case up-line switchgear will operate in zone 2 (or 3) thus causing a more wide-spread outage. Therefore, depending upon DG technology, location, and distribution feeder characteristics, an impact study may be required. Any "streamlining" process rules MUST be constrained to inverter-based DG ONLY!"

Screen 5: Interrupting Capability of Existing Devices (Shall Not Cause Equipment on the System to Exceed 87.5% of the Short Circuit Interrupting Capability)

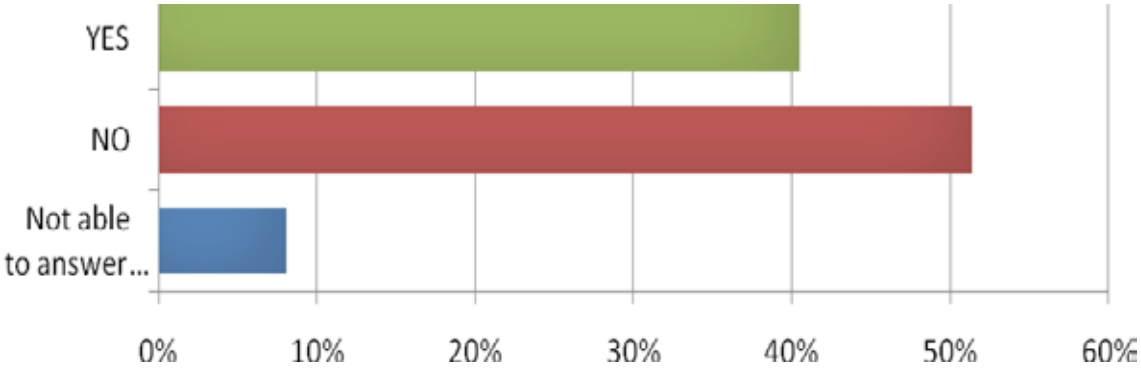

Figure 13: SME Response to: "Do You Support Updating Screen #5?"

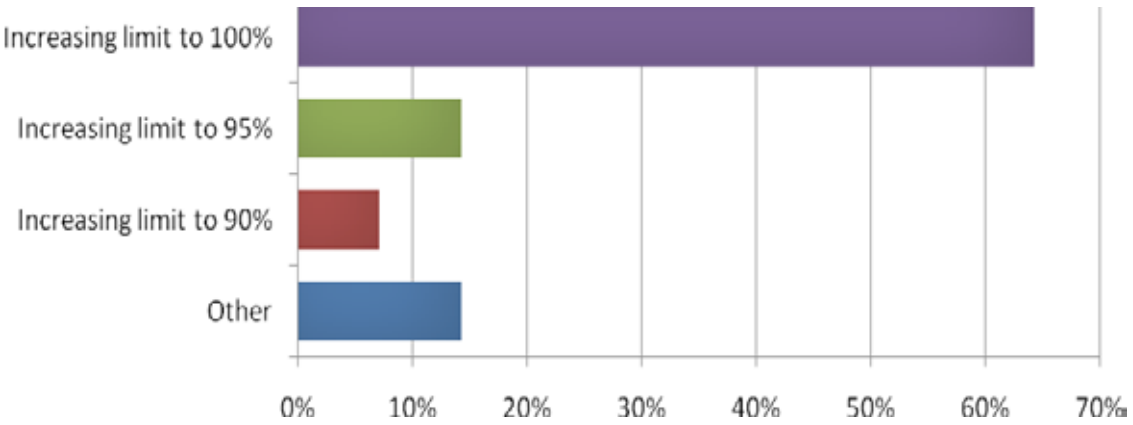

Figure 14: SME Response to: "If You Support Updating this Size Limit, What Change Would You Recommend? (Screen #5)"

The "Other" options included reducing the limit to 85% as well as increasing the limit to 100% in the first 2-3 cycles following the fault. Clearly, the majority of SMEs who support updating this screen support increasing the limit to 100%.

The following are some representative responses when the SMEs were asked to explain their position on this screen:

"Although the arguments for updating this screen may be valid for inverter-based technology, this screen is utilized for all type of generation projects including non-inverter-based technology"

"The margin in this screening limit is reasonable."

"For inverter-based systems, this should not be a problem unless the system is already very close to the limit. Because fault current is increasing on distribution systems for other reasons rather than the addition of DG on that circuit (increasing substation transformer size, upgrading transmission system, etc.) we need to be very conservative when evaluating the addition of new DG on distributions that are pushing the limit of fault current already."

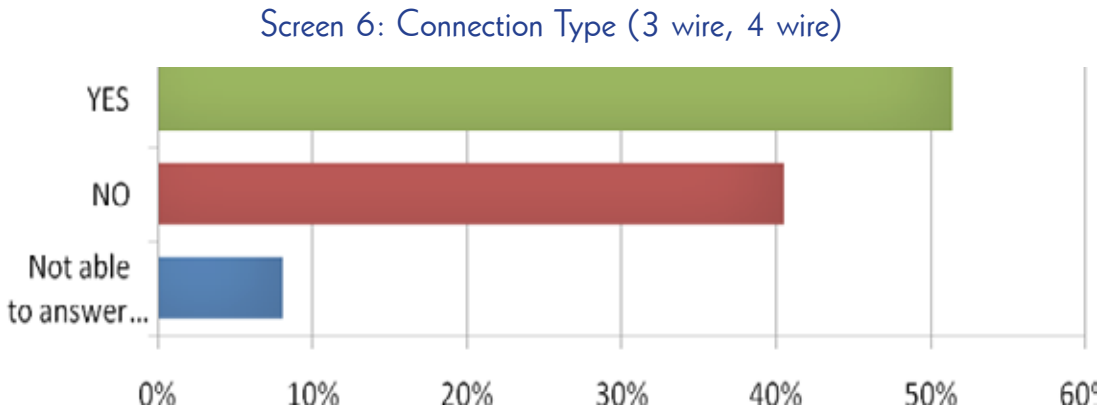

Figure 15: SME Response to: "Do You Support Updating Screen #6?"

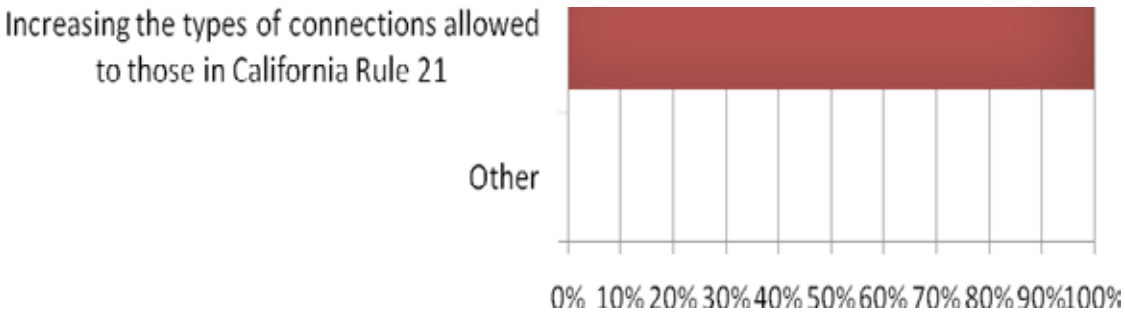

Figure 16: SME Response to: "If You Support Updating this Size Limit, What Change Would You Recommend? (Screen #6)"

Fewer SMEs responded to the request to provide an explanation of their position on this screen than for the other screens. Those who did respond provided a variety of reasons for either supporting or not supporting an update. Some of the comments were:

"Having participated in the development of the Rule 21 table, I believe it was vetted thoroughly. I don't see any reason [it] couldn't be applied elsewhere."

"Again, this is a screen. The rule 21 language expects the utility to determine circuit peak load to validate the last type of connection, and this is not a screen issue, it's a study issue."

"This appears to provide sufficient protection and allows additional interconnections."

"The California rule requires a study of all of the possible topologies. On transmission, that is simple, not so on distribution."

Screen 7: Single-Phase Shared Secondary System Size Limit (Capacity on the Shared Secondary Shall Not Exceed 20 kW)

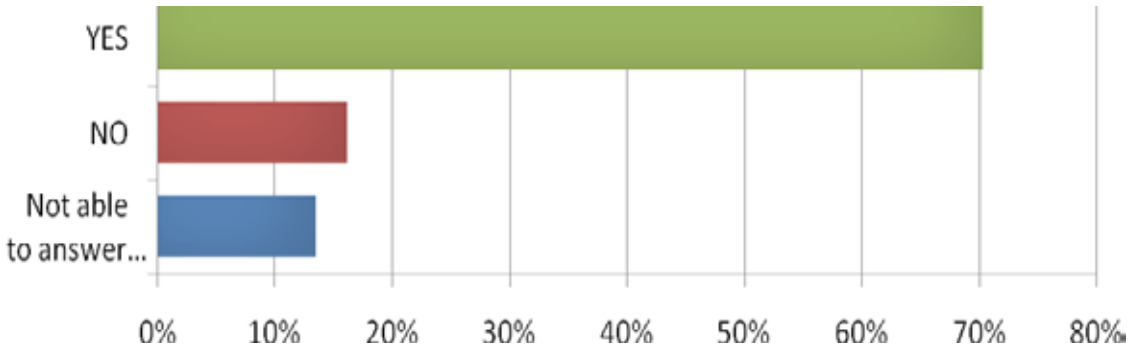

Figure 17: SME Response to: "Do You Support Updating Screen #7?"

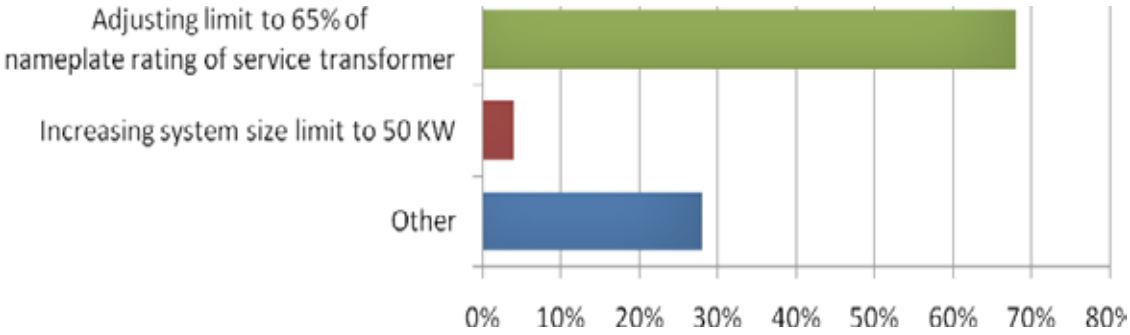

Figure 18: SME Response to: "If You Support Updating this Size Limit, What Change Would You Recommend? (Screen #7)"

More than 25% of SMEs who support updating this screen preferred an update other than the two options included as answer choices. The suggestions included: "should not allow more than 50% of transformer nameplate" and "Adjusting limit to 85% of service transformer nameplate."

The explanation of their positions included comments such as:

> "The % of nameplate criteria is better because the 20 kVA value assumes a particular range of transformer sizes. Exactly what percentage should be used (65% or other) could be worth further discussion."
>
> "There is a wide diversity in the number of customers connected to a single transformer. Neither a kVA, nor a percentage screen is correct."
>
> "Service transformer size can be changed to allow larger DR."

"65% may be fine, recognizing that typical sizes found in the field are often 25 kW units. Most residential installations are from 3-8 kW in size, so the 65% factor will start to limit the number of installations on these systems faster than the 20 kW size does now."

Screen 8: Single-Phase Shared Secondary (20% Imbalance Limit)

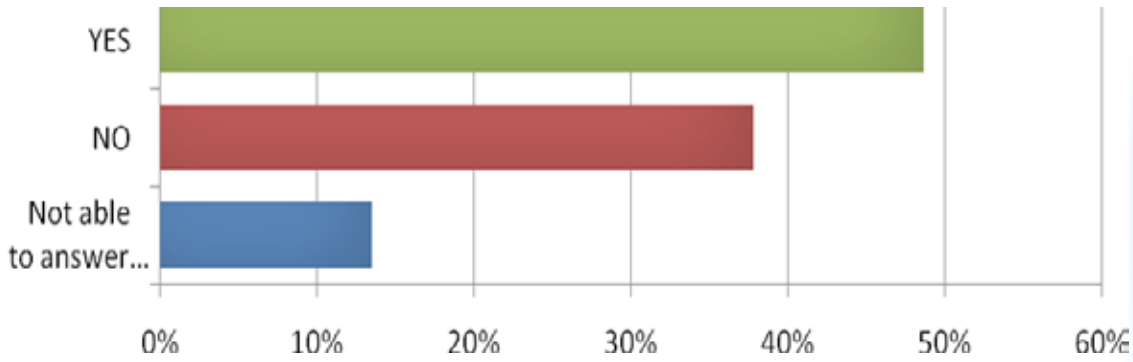

Figure 19: SME Response to: "Do You Support Updating Screen #8?"

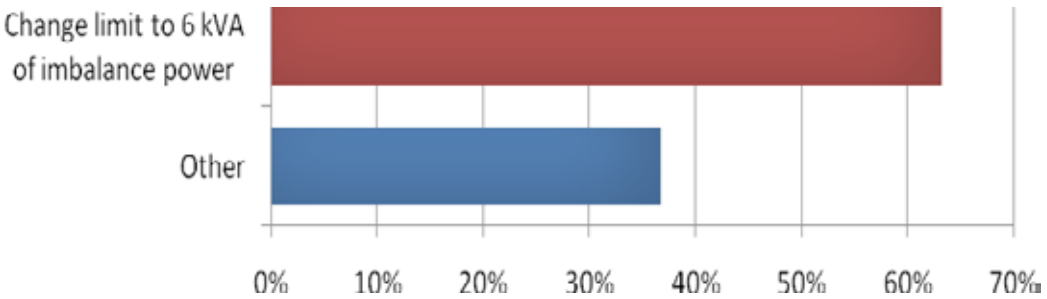

Figure 20: SME Response to: "If You Support Updating this Size Limit, What Change Would You Recommend? (Screen #8)"

More than one-third of the SMEs supporting an update to this screen preferred something other than the offered "change limit to 6 kVA of imbalance power" option. The other updates, or comments, that were received included: "use percentage (similar to NM rule)" and "10 to 20 percent of transformer rating."

The SME comments explaining their position on this issue included:

> "6 kVA of a 10 kVA transformer is too high of a limit. Even for a 15 kVA transformer, 6 kVA represents 40% imbalance. Imbalance issue goes beyond neutral return current. Voltage imbalance will also occur and can be a significant problem particularly if utility regulating equipment is 3-phase and not single-phase based."
>
> "The amount of imbalance should depend on the size of the service transformer."
>
> "If the transformer is dedicated to the use of the DER then it has to be rated, if it has not been tested and its rating certified as a generated step-up transformer. Standard distribution transformer kVA rating is based on the secondary voltage taking into consideration the voltage drop through the transformer. When used as a generator step-up transformer its secondary can be overexcited."

Screen 9: Size Limit in an Area Where There are Known Stability Limitations

(Shall not Exceed 10 MW)

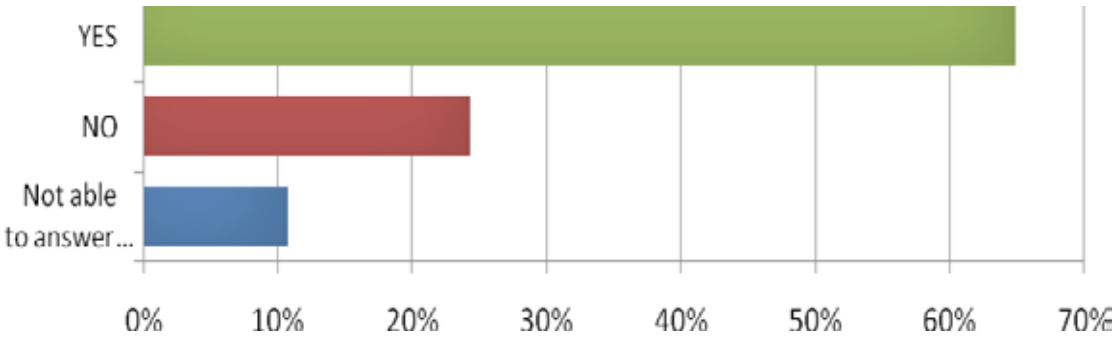

Figure 21: SME Response to: "Do You Support Updating Screen #9?"

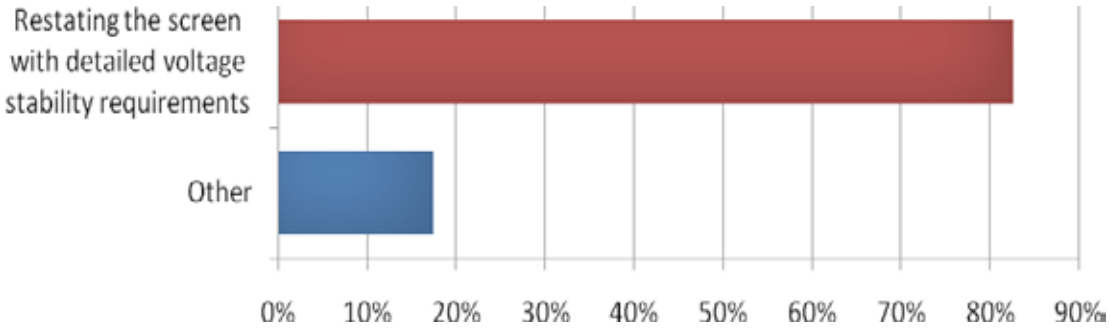

Figure 22: SME Response to: "If You Support Updating this Size Limit, What Change Would You Recommend? (Screen #9)"

The SMEs who supported an update to this screen and chose the "Other" option to the second question wrote responses that mostly indicated restating the screen with both voltage and power stability requirements. One SME suggested the screen be removed entirely.

The SMEs provided the following comments on their positions on this screen:

> "I agree with the arguments stated, it needs to be tied to something more concrete."
>
> "Utility distribution engineers do not know how to address the screen as it is written now."
>
> "As written, the rules are not clear. Transient instability is a study result, not a chronic condition."
>
> "Low frequency stability concerns will definitely be impacted by high penetrations of inverter-based DE. In some RTOs, high penetrations of DE may actually be operated as a Power System Stabilizer to dampen oscillation. This is well within the capability of existing inverters."

Comparison of Utility Versus Non-Utility SME Respondents

There were significant differences in the responses of SMEs who identified themselves as currently having a role with a utility and those who identified themselves as having a non-utility affiliation. The figure below compares the support of utility vs. non-utility SME respondents for updating the limits of the 10 kW Inverter Process and each of the eight FERC SGIP screens they were asked about. The issue with the largest difference is the 10 kW Inverter Process.

There is also a significant difference on several other issues. Perhaps most noteworthy are screens #2 and #3 dealing with capacity limits. The non-utility SMEs were more supportive of updating these screens as well as the 10 kW Inverter Process.

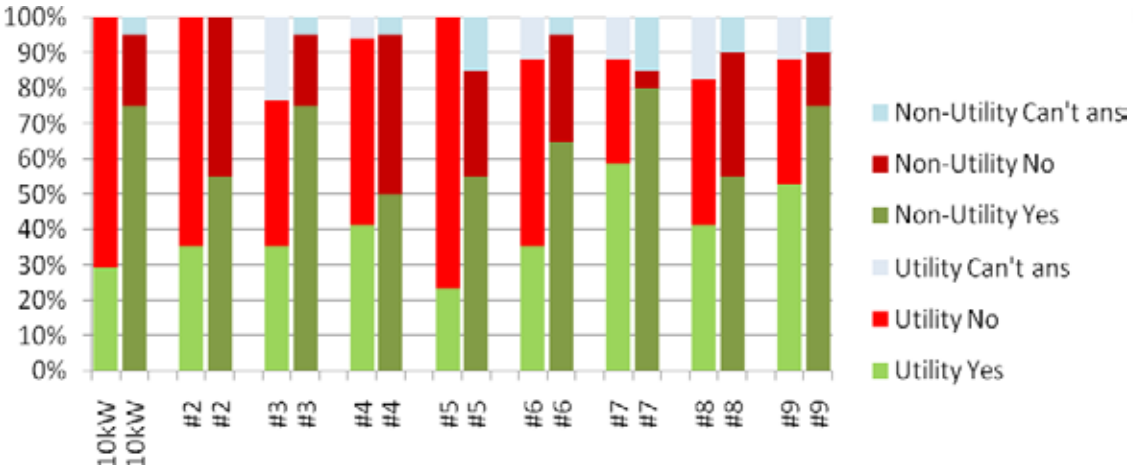

Figure 23: Breakdown of support for Screen Update by Utility SMEs and Non-Utility SMEs

Surprisingly, only two of the 17 (11.8%) utility SMEs indicated recent DG interconnection experience in California, yet 14 of the 20 (70%) non-utility SMEs indicated recent California experience.

More than half of the interconnected inverter-based DG systems installed in the United States are installed in California, so—not surprisingly—many areas with the highest levels of PV grid penetration are in that state. We were interested in the support of SME respondents with DG interconnection experience in California on the issue of updating the 15% line section limit (Screen #2) compared to the support of the complete pool of SME respondents. Of the 17 respondents who indicated California DG interconnection experience, 10 said they would support updating Screen #2 (59%) and only seven (41%) did not support updating this screen. Of those supporting updating Screen #2, nearly two-thirds supported increasing the limit to 30% of line section peak load.

FERC-SGIP screens - Solar ABCs study

1. Questionnaire Overview

Goals of this Questionnaire
The purpose of this questionnaire is to collect expert opinions on the FERC Small Generator Interconnection Procedures (SGIP) screens. IREC will use this feedback to develop a report for the DOE Solar America Board for Codes and Standards (Solar ABCs), recommending updates to the FERC SGIP screens or establishing a new set of model screens. The SGIP screens haven't been substantially revised since original passage of the SGIP in FERC ORDER 2006 on May 12, 2005. Since that time, the U.S. has installed over 1,200 MW of grid-tied solar. We believe that the solar industry has gained enough experience and knowledge to warrant a reexamination of the SGIP screens. **We greatly appreciate your time and expertise in this project. If you have questions please feel free to call:**

- **Tommy Cleveland: (919) 515-9432**
- **Michael Sheehan: (206) 232-2493**

Overview of the Questionnaire
Throughout the questionnaire you will find both multiple-choice and open-ended questions. We request that you answer all questions marked with an asterisk; the questionnaire requires an answer to these questions before you can advance to the next page.

The questionnaire begins with some background on the SGIP screens for your reference. The next page focuses on the "10 kW Inverter Process" and whether it is appropriate to apply these procedures to systems larger than 10kW. The following eight pages of questions reference SGIP screens #2 through #9. Each of these pages starts with the existing language of the screen, a summary of the precedent for the current version of the screen, and a summary of arguments for updating the screen. Below this brief guide to each screen there will be these three questions:

1. Do you support updating this screen? Yes, No, or Can't Answer *(This question requires an answer)
2. If you support updating this screen, what change would you recommend?
3. Please briefly provide an explanation of your position.

The questionnaire concludes with a page of background questions to collect some relevant demographic data, which will help us understand the perspective of each respondent.

Thank You
To thank you for taking the time to share your expertise with us we will send everyone who completes the questionnaire a summary of the voting results.
Respondents will also receive a copy of the final report when it is published.

Stay Involved
This questionnaire is not your only chance to provide input. You are also invited to participate in future stakeholder meetings for this study, about which you will receive email announcements. You may also visit www.solarabcs.com or email Tommy_Cleveland@ncsu.edu for information.

Final Outcome
The final outcome of this study of the Solar ABCs will be a paper suggesting updates to the FERC SGIP screens based on the input received in this questionnaire.

FERC-SGIP screens - Solar ABCs study

2. Confidentiality Policy and Options

Confidentiality Policy
Unless the respondent chooses to opt-out of confidentiality, the data collected from each respondent will not be released in full or in part. The responses you provide in the questionnaire will be aggregated for the purposes of producing the report. Only the report authors will have access to the questionnaire responses.
Please contact Tommy_Cleveland@ncsu.edu (919) 515-9432 with any questions regarding this policy.

*** 1. Please consider opting-out of the confidentiality policy. This will allow the authors to include more information in the final report, which we believe will improve the quality of the final Solar ABCs report.**

Please select the level of confidentiality you desire.

◯ Keep my responses fully confidential. I understand the confidentially policy stated above.

◯ I would like to partially opt-out of the confidentiality policy: The authors may anonymously quote from my responses (quotes may be used, but the only identification of the source revealed will be a State or region of the country).

◯ I would like to fully opt-out of the confidentiality policy: The authors may share and quote any of my responses.

FERC-SGIP screens - Solar ABCs study

3. Overview of FERC SGIP Screens

Overview of the FERC Small Generator Interconnection Procedures
The Federal Energy Regulatory Commission (FERC) "small generator" interconnection standards for distributed energy resources up to 20 megawatts (MW) in capacity include a Small Generator Interconnection Procedures (SGIP) document and a Small Generator Interconnection Agreement (SGIA). The FERC's standards apply only to facilities subject to the jurisdiction of the commission; these facilities mostly include those that interconnect at the transmission level. The FERC's standards generally do not apply to distribution-level interconnection, which is regulated by state public utilities commissions. However, the FERC has noted that its interconnection standards for small generators should serve as a useful model for state-level standards.

FERC's Small Generator Interconnection Procedures (SGIP) contains a series of technical screens for the Fast-Track interconnection process of generation facilities up to 2 Megawatts (MW). Systems that pass the screens qualify for the Fast-Track interconnection process (SGIP Section 2), allowing them to avoid lengthy/expensive interconnection studies (SGIP Section 3). Inverter-based generators 10 kW or smaller that pass the screens qualify for a simplified interconnection process known as the "10 kW Inverter Process". Projects that fail the screens should be able to interconnect after the needed studies are complete and any needed upgrades identified by those studies are in place.

These screens generally apply to a range of systems, including inverter-based facilities such as solar energy systems. There is recent evidence to suggest that some of the existing screens may be more stringent than needed for inverter-based generators. Inverters are inherently very "controllable" and their use in utility applications has risen from a few thousand systems as of 2002 to over 69,000 systems by the end of 2008. Because inverters are power electronic devices, it is possible to incorporate safety and operational features into their controls, such as providing fail-safe designs that prevent the inverter from operating unless its protective functions are working properly. Inverter-based and rotating generators are treated differently in the codes and standards, so that properly designed and tested inverter-based devices require little (if any) additional external protection equipment.

The current screens may be found in section 2.2.1 of the Small Generators Interconnection Procedures (SGIP). Here is a summarized list for your convenience:(Link to access full SGIP document)

1. Tariff jurisdiction: This is non-technical and not addressed in this questionnaire.
2. Aggregate generating capacity vs. line section peak load (max 15%)
3. Network protectors (shall not exceed the smaller of 5% of a spot network's maximum load or 50 kW)
4. Short circuit contribution (shall not contribute more than 10 % to the distribution circuit's maximum fault current at the point on the high voltage primary level)
5. Interrupting capability of existing devices (shall not cause equipment on the system to exceed 87.5 % of the short circuit interrupting capability)
6. Connection type (3 wire, 4 wire)
7. Single-phase shared secondary system size limit (capacity on the shared secondary shall not exceed 20 kW)
8. Single-phase shared secondary (20% imbalance limit)
9. Size limit in an area where there are known stability limitations (shall not exceed 10 MW)
10. Construction would not be required by the utility: This is non-technical

FERC-SGIP screens - Solar ABCs study

4. 10 kW Inverter Process Size Limit (10 kW)

Present FERC SGIP "10 kW Inverter Process" Size Limit (SGIP Attachment 5): The title of Attachment 5 is "Application, Procedures, and Terms and Conditions for Interconnecting a Certified Inverter-Based Small Generating Facility No Larger than 10 kW."

SGIP Attachment 5, paragraph 4.0, first sentence: "The Company verifies that the Small Generating Facility can be interconnected safely and reliably using the screens contained in the Fast Track Process..."

In summary, the "10 kW Inverter Process" offers a simplified interconnection application, within the SGIP Section 2 "Fast Track" screens.

Argument for Keeping the SGIP 10 kW Inverter Process Size Limit at 10 kW

The 10 kW inverter-based process came from a stakeholder group in Massachusetts, presumably in 2004 (see footnote 46 of FERC Order 2006). The state had few, if any, interconnections of systems over 10 kW at the time. Looking to national and international experience, that group still found it reasonable to have a 10 kW cut-off for simplified procedures. Experience since 2005 has shown the 10 kW limit on the very simplified process to be safe.

Argument for Updating the SGIP 10 kW Inverter Process Size Limit to 25 kW

The concise argument for including certified, inverter-based systems up to 25 kW in the simplified interconnection process (currently known as the "10 kW Inverter Process") is that the dramatic rise in the number of inverter-based systems world-wide has not revealed interconnection complications in the 10 kW to 25 kW range, or foreseeable problems in that range.

In New York all systems up to 25 kW are governed by a simplified process.

Additionally, increasing the limit to 25 kW not only simplifies the interconnection process for many small systems, but also illustrates the importance of relying on national technical standards. It is possible to state in a single sentence of a document that systems must meet the requirements established by UL, IEEE, and the National Electric Code (NEC). Several states now use a one- or two-page interconnection agreement for very small DG systems, especially for net metered systems.

The Interstate Renewable Energy Council (IREC) recommends moving the limit to 25 kW by including this limit in its widely-used Model Interconnection Rule..

IREC Model Rule

> "Level 1 Screening Criteria and Process for Inverter-Based Generating Facilities Not Greater than 25 kW:"

FERC-SGIP screens - Solar ABCs study

*** 1. Do you support updating the size limit for the simplified process for small inverter-based systems, currently known as the "10 kW Inverter Process"?**

- ◯ YES
- ◯ NO
- ◯ I am not able to answer YES or NO because...

2. If you support updating this size limit, what change would you recommend?

- ☐ Increasing limit to 15 kW
- ☐ Increasing limit to 20 kW
- ☐ Increasing limit to 25 kW
- ☐ Increasing limit to 50 kW
- ☐ Other (please specify)

3. Please briefly provide an explanation of your position.

FERC-SGIP screens - Solar ABCs study

5. Screen #2: Aggregate generating capacity vs. line section peak load (max 1...

Present FERC SGIP Screen 2.2.1.2 "For interconnection of a proposed Small Generating Facility to a radial distribution circuit, the aggregated generation, including the Small Generating Facility, on the circuit shall not exceed 15% of the line section peak load as most recently measured at the substation. A line section is that portion of a Transmission Provider's electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line. "

Argument for Keeping the FERC SGIP Screen 2.2.1.2 at 15% of the line section peak load

The intent of this screen is to assure that generation on a line section will not exceed load at any time, but utilities typically track peak loads and not minimum loads. Fifteen percent of peak load was established in the FERC SGIP procedures as a conservative estimate of minimum load. This limit has not provided any known problems. Existing state rules and utilities have commonly accepted the FERC SGIP screen 2.2.1.2, for example California Rule 21:

California Rule 21 provides some discussion on this issue:

1. Low penetration of Generating Facility installations will have a minimal impact on the operation and load restoration efforts of Electrical Company's (EC) Distribution System.
2. The operating requirements for a high penetration of Generating Facilities may be different since the impact on EC's Distribution System will no longer be minimal, therefore requiring additional study or controls.

Argument for Increasing the FERC SGIP Screen 2.2.1.2 generating capacity versus line section peak load limit

Below are excerpts from two recent sources suggesting higher PV penetration levels are possible without complications.

The Executive Summary of the Renewable Systems Interconnection Study: Utility Models, Analysis, and Simulation Tools, SANDIA REPORT: SAND2008-0945 Printed February 2008

> "As penetration levels rise on individual feeders into the 30% range, concerns emerge regarding the dynamic performance of distributed generation (DG). A need will develop for dynamic analysis tools used to study generator oscillations, damping, and anti-islanding controls for large numbers of generators. Existing tools must be upgraded, advanced system models for PV and other distributed generators must be developed, and these must be improved to accommodate a wider range of users."

Interconnecting PV on New York City's Secondary Network November 2009 Distribution System, NREL/ TP-7A2-46902 K. Anderson, M. Coddington, K. Burman, S. Hayter, B. Kroposki, and A. Watson

> "PV penetration levels of 20% to 30% are generally considered to be the maximum level allowable in radial distribution systems before changes to the system are necessary."

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Additional Issue: Clarity Needed in Existing Screen

The FERC procedures call for aggregate generation on the circuit to not exceed 15% of line section peak load, when the relevant comparison would seem to be line section generation vs. line section peak load. FERC Order 2006 has no discussion on this point.
Please see question 4 below to provide input on this issue.

*** 1. Do you support updating this screen?**

- ◯ YES
- ◯ NO
- ◯ I am not able to answer YES or NO because...

2. If you support updating this screen, what change would you recommend?

- ☐ Increasing limit to 20% of line section peak load
- ☐ Increasing limit to 25% of line section peak load
- ☐ Increasing limit to 30% of line section peak load
- ☐ Increasing limit to greater than 30% of line section peak load
- ☐ Other (please specify)

3. Please briefly provide an explanation of your position.

4. Regarding the section on the page above entitled "Clarity Needed in Existing Screen", I believe that the relevant comparison is

- ◯ Correct as stated in the current screen, (*aggregate generation on the circuit* vs. line section peak load)
- ◯ Different than stated in the current screen, (*line section generation* vs. line section peak load)

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6. Screen #3: Network protectors (Max is the smaller of 5% of a spot network's...

Present FERC SGIP Screen 2.2.1.3 "For interconnection of a proposed Small Generating Facility to the load side of spot network protectors, the proposed Small Generating Facility must utilize an inverter-based equipment package and, together with the aggregated other inverter-based generation, shall not exceed the smaller of 5% of a spot network's maximum load or 50 kW. "

Argument for Keeping the FERC SGIP Screen 2.2.1.3 at 5% of spot network or 50 kW

The existing screen has been adopted by many states. In Pennsylvania the screen states "(f): for interconnection of a proposed small generator facility to the load side of spot network protectors, the proposed small generator facility shall utilize an inverter-based equipment package. The customer interconnection equipment proposed for the small generator facility must be certified, and when aggregated with other generation, may not exceed 5% of the spot network's maximum load."

There are a couple of terms that need to be defined:

1. Spot Network means a Secondary Network system consisting of two or more network units at a single site. The low-voltage network side terminals of these network units are connected together with bus or cable.
2. Network System means an AC power Distribution System in which Customers are served from three-phase, four-wire low-voltage circuits supplied by two or more Network Transformers whose low-voltage terminals are connected to the low-voltage circuits through network protectors. The Network system has more than two high-voltage primary feeders, with each primary feeder typically supplying multiple Network Transformers, depending on network size and design.

Argument for Changing the FERC SGIP Screen 2.2.1.3 limit of 10% or 200 kW whichever is less

There is a new study ("Limit on Generation Size on Area Networks", Prepared by Mr. David Smith PE, consultant) on the limit on generation size on area networks. The study states:

> "The maximum amount of inverter based generation to be allowed on an area network can be expressed as either a percentage of the minimum load, or as a percentage of the installed transformer capacity. Considering three-phase faults on the primary feeder and at the substation, it should be expressed in terms of the installed network transformer capacity. Considering protector operation (sitting open cycling, and pumping) during unfaulted conditions, it is perhaps better to define the generation in terms of minimum load on the area network. From the standpoint of defining for a given area network the allowed amount of inverter based generation, it would be easier to administer if the criteria were expressed in percent of installed network transformer capacity. The regulations in the State of NJ place an upper limit on the amount of inverter based generation that can be placed on the area network, said limit being 10 percent of the annual minimum load, or 500 kW, whichever is less. This 10 percent level is consistent with the findings of this study for area networks, where it is concluded that inverter based generation in the range of 3% to 4% of the installed network transformer capacity is acceptable."

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In addition, Consolidated Edison of New York, Inc. (Con Edison), in an effort to reduce barriers to interconnection of customer-owned DG, has announced that while it will still perform a detailed, site-specific study when it receives a request for interconnection to its distribution network systems (secondary and spot networks), inverter-based solar generators up to 200 kW may interconnect to the company's distribution network system without such a study.

*** 1. Do you support updating this screen?**

- ◯ YES
- ◯ NO
- ◯ I am not able to answer YES or NO because...

2. If you support updating this screen, what change would you recommend?

- ☐ Increasing limit to the smaller of 5% of spot network peak load or 200 kW
- ☐ Increasing limit to the smaller of 10% of spot network peak load or 200 kW
- ☐ Increasing limit to the smaller of 10% of spot network peak load or 500 kW.
- ☐ Increasing limit to 200 kW (removing percentage based portion of limit)
- ☐ Increasing limit to 500 kW (removing percentage based portion of limit)
- ☐ Other (please specify)

3. Please briefly provide an explanation of your position.

7. Screen #4: Short circuit contribution (10% limit)

Present FERC SGIP Screen 2.2.1.4 "The proposed Small Generating Facility, in aggregation with other generation on the distribution circuit shall not contribute more than 10% to the distribution circuit's maximum fault current at the point of the high voltage (primary) level nearest the proposed point of change of ownership."

Argument for Keeping the FERC Screen 2.2.1.4 at 10%

The FERC SGIP screen have two screens linked to fault current: First (2.2.1.4), the aggregate distributed generation on a distribution circuit is not permitted to contribute more than 10% of the available fault current at the primary voltage point closest to the point of coupling with the generator. Second (2.2.1.5), a distributed generation interconnection is not permitted to result in available fault current exceeding 87.5% of the interrupting capability of a distribution protective device.

Existing state rules and utilities have commonly accepted FERC SGIP screen 2.2.1.4.

Argument for Changing the FERC Screen 2.2.1.4 to 20%

The fault current contribution from induction motors is usually much larger than that of current controlled inverter-DG. It is common practice to ignore the fault current contribution of induction motor loads, particularly small, distributed motor loads, in distribution overcurrent conditions.

The fault current from DG is much smaller than that of the motor loads. Thus, there is ample precedent for considering current-controlled inverter-based DG as an insignificant short circuit current condition.

DG Power Quality, Protection and Reliability Case Studies Report August 2003, NREL/SR-560-34635

As a conclusion, under both three-phase and single-phase fault, the inverter-based current controlled DG has little impact on fault contribution and fuse-saving strategy. The GE NREL 2003 study states:

> "Figure 32 shows the fault, grid and motor (transformer high side) currents. It can be observed that the motor phase current has a phase jump at the beginning of the fault, signifying that the motor momentarily feeds power into the grid. There is an initial drop in the current magnitude because of the drop in the voltage magnitude. However, it can be observed in Figure 33 that the per-cycle I2t increases as the fault proceeds because of the increased motor slip, caused by the sag in the motor terminal voltage. Once the fault is cleared, the terminal voltage increases leading to an inrush into the induction machine. Figure 34 shows the motor torque and speed response to the fault. It is clearly seen that the fault current contribution from motor is larger than inverter-DG."
>
> Based results on Figure 34 on this GE NREL Study I would remove the requirement for inverter based system between 87.5 and 100% of their short circuit interrupting capability."

Understanding Fault Characteristics of Inverter-Based Distributed Energy Resources, NREL/TP-550-46698

The conclusions of the paper suggest that fault current contributions from inverter-based DG may occur for short enough time periods to be ignored: The conclusions state:

> "The current industry's practice regarding fault current level assessment for setting protective relays has been to apply a "rule of thumb" of 2 times rated continuous current for

FERC-SGIP screens - Solar ABCs study

DER. This seems to be the standard practice at low levels of DER penetration. Tests of 2 grid tied inverter systems at NREL suggest that the fault current is typically higher, but for much shorter time periods (2-4 times rated current for 0.06 – 0.25 cycles). This time period is typically within the subtransient reactance values for synchronous generators and trip times for circuit breakers, and therefore can possibly be ignored. What effect this may have on the protective relays at higher levels of DER penetration is not well understood and warrants continued research in this area."

*** 1. Do you support updating this screen?**

- ◯ YES
- ◯ NO
- ◯ I am not able to answer YES or NO because...

2. If you support updating this screen, what change would you recommend?

- ☐ Increasing limit to 15%
- ☐ Increasing limit to 20%
- ☐ Increasing limit to 25%
- ☐ Increasing limit to greater than 25%
- ☐ Other (please specify)

3. Please briefly provide your an explanation of your position.

FERC-SGIP screens - Solar ABCs study

8. Screen #5: Interrupting Capability of Existing Devices (not to exceed 87.5%...

Present FERC SGIP Screen 2.2.1.5 "The proposed Small Generating Facility, in aggregate with other generation on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed 87.5% of the short circuit interrupting capability; nor shall the interconnection be proposed for a circuit that already exceeds 87.5% of the short circuit interrupting capability."

Argument for Keeping the FERC Screen 2.2.1.5 at 87.5%

The FERC SGIP screen have two screens linked to fault current: First (2.2.1.4), the aggregate distributed generation on a distribution circuit is not permitted to contribute more than 10% of the available fault current at the primary voltage point closest to the point of coupling with the generator. Second (2.2.1.5), a distributed generation interconnection is not permitting to result in available fault current exceeding 87.5% of the interrupting capability of a distribution protective device.

Existing state rules and utilities have commonly accepted FERC SGIP screen 2.2.1.5.

Argument for Changing the FERC Screen 2.2.1.5 to 100%

The fault current from DG is much smaller than that of the motor loads. Thus, there is ample precedent for considering current-controlled inverter-based DG as an insignificant short circuit current condition.

DG Power Quality, Protection and Reliability Case Studies Report August 2003, NREL/SR-560-34635

As a conclusion, under both three-phase and single-phase fault, the inverter-based current controlled DG has little impact on fault contribution and fuse-saving strategy. The GE NREL 2003 study states:

> "Figure 32 shows the fault, grid and motor (transformer high side) currents. It can be observed that the motor phase current has a phase jump at the beginning of the fault, signifying that the motor momentarily feeds power into the grid. There is an initial drop in the current magnitude because of the drop in the voltage magnitude. However, it can be observed in Figure 33 that the per-cycle I2t increases as the fault proceeds because of the increased motor slip, caused by the sag in the motor terminal voltage. Once the fault is cleared, the terminal voltage increases leading to an inrush into the induction machine. Figure 34 shows the motor torque and speed response to the fault. It is clearly seen that the fault current contribution from motor is larger than inverter-DG."
>
> Based results on Figure 34 on this GE NREL Study I would remove the requirement for inverter based system between 87.5 and 100% of their short circuit interrupting capability".

Understanding Fault Characteristics of Inverter-Based Distributed Energy Resources, NREL/TP-550-46698

The conclusions of the paper suggest that fault current contributions from inverter-based DG may occur for short enough time periods to be ignored: The conclusions state:

> "The current industry's practice regarding fault current level assessment for setting protective relays has been to apply a "rule of thumb" of 2 times rated continuous current for DER. This seems to be the standard practice at low levels of DER penetration. Tests of 2

FERC-SGIP screens - Solar ABCs study

grid tied inverter systems at NREL suggest that the fault current is typically higher, but for much shorter time periods (2-4 times rated current for 0.06 – 0.25 cycles). This time period is typically within the subtransient reactance values for synchronous generators and trip times for circuit breakers, and therefore can possibly be ignored. What effect this may have on the protective relays at higher levels of DER penetration is not well understood and warrants continued research in this area."

*** 1. Do you support updating this screen?**

- ◯ YES
- ◯ NO
- ◯ I am not able to answer YES or NO because...

2. If you support updating this screen, what change would you recommend?

- ☐ Increasing limit to 100%
- ☐ Increasing limit to 95%
- ☐ Increasing limit to 90%
- ☐ Other (please specify)

3. Please briefly provide an explanation of your position.

FERC-SGIP screens - Solar ABCs study

9. Screen #6: Connection type (3 wire, 4 wire)

Present FERC SGIP Screen 2.2.1.6 "Using the table below, determine the type of interconnection to a primary distribution line. This screen includes a review of the type of electrical service provided to the Interconnecting Customer, including line configuration and the transformer connection to limit the potential for creating over-voltages on the Transmission Provider's electric power system due to a loss of ground during the operating time of any anti-islanding function."

Primary Distribution Line Type	Type of Interconnection to Primary Distribution Line	Result/Criteria
Three-phase, three wire	3-phase or single phase, phase-to-phase	Pass screen
Three-phase, four wire	Effectively-grounded 3 phase or Single-phase, line-to-neutral	Pass screen

---

Argument for Keeping the FERC Screen 2.2.1.6 at present types of interconnection

Existing model rules, state rules, and utilities have commonly accepted the FERC SGIP screen 2.2.1.6, for example IREC Model Rule.

IREC Model Rule

> "If the proposed generator is interconnected to the Electric Power System (EPS) as shown in the table below:
>
> | Primary-Distribution Line Type | Type of Interconnection to Primary-Distribution Line | Result/Criteria |
> |---|---|---|
> | Three-phase, 3-wire | 3-phase or single phase, phase-to-phase | Pass screen |
> | Three-phase, four wire | Effectively-grounded 3 phase or Single-phase, line-to-neutral | Pass screen |
>
> "

Argument for Changing the FERC Screen 2.2.1.6 to additional types of interconnections

California Rule 21 allows more possible line configurations than the FERC SGIP screen. California Rule 21 allows mixed 3-wire and 4-wire configurations with the limitation of DG capacity shall be less than or equal to 10% of the line section's peak load.

California Rule 21 "Line Configuration" Screen Significance

> "If the Electric Company's primary distribution system is 3-wire, or the DG interconnection transformer is single-phase (line-to-neutral), then there is no concern about over-voltages to the utility, or to other customers' equipment caused by the loss of a system's neutral grounding while anti-islanding protection is in operation. The utility identifies the primary-distribution line configuration. Based on the proposed interconnection type, the utility determines from the table below if the DG passes the screen.

FERC-SGIP screens - Solar ABCs study

Primary-Distribution Line Type	Type of Interconnection to Primary-Distribution Line	Result/Criteria
Three-phase, 3-wire	Any	Pass screen
Three-phase, four wire	Single-phase, line-to-neutral	Pass screen
Three-phase, 4-wire (For any line that has such a section or mixed 3-wire and 4-wire)	All others	To pass, aggregate DG capacity shall be less than or equal to 10% of the line section's peak load.

"

Additionally, THE NEW MEXICO INTERCONNECTION MANUAL uses the same rules as CA Rule 21 regarding connection type.

*** 1. Do you support updating this screen?**

- ◯ YES
- ◯ NO
- ◯ I am not able to answer YES or NO because...

2. If you support updating this screen, what change would you recommend?

- ☐ Increasing the types of connections allowed to those in California Rule 21 (as in table above)
- ☐ Other (please specify)

3. Please briefly provide an explanation of your position.

10. Screen #7: Single-phase shared secondary system size limit (20 kW)

Present FERC SGIP Screen 2.2.1.7 "If the proposed Small Generating Facility is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed Small Generating Facility, shall not exceed 20 kW."

Argument for Keeping the FERC Screen 2.2.1.7 at present 20 kW level

Shared secondary - 20 kVA maximum: To allow customers on a shared single-phase secondary to have equal access to the capacity of the shared utility distribution transformer, a limit is placed on individual customer's Generating Facility capacity. This limit allows for some diversity of loads and generation at each of the customer's electrical service in a shared secondary without overloading the serving distribution transformer. Existing state rules and utilities have commonly accepted the FERC SGIP screen 2.2.1.7 approach, for example California Rule 21.

California Rule 21

> "For single-phase Generators connected to a shared single-phase secondary system, the maximum Net Nameplate Rating of the Generating Facilities shall be 20 kVA. Generators connected to a center-tapped neutral 240-volt service must be installed such that no more than 6 kVA of imbalanced power is applied to the two "legs" of the 240-volt service. For Dedicated Distribution Transformer services, the maximum Net Nameplate Rating of a single-phase Generating Facility shall be the transformer nameplate rating."

Argument for Changing the FERC Screen 2.2.1.7 to 65% nameplate rating of service transformer

Instead of the system size limit approach used in the existing SGIP screen, New Mexico uses the percentage of the nameplate rating of the service transformer as the screen metric. This approach may better capture imbalance concerns on a shared secondary.

THE NEW MEXICO INTERCONNECTION MANUAL

> "If the proposed Generating Facility is to be interconnected on a single-phase Shared Secondary, the aggregate Generating Facility capacity on the Shared Secondary, including the proposed Generating Facility, shall not exceed 65% of the transformer nameplate rating."

FERC-SGIP screens - Solar ABCs study

*** 1. Do you support updating this screen?**

- ◯ YES
- ◯ NO
- ◯ I am not able to answer YES or NO because...

2. If you support updating this screen, what change would you recommend?

- ☐ Adjusting limit to 65% of nameplate rating of service transformer
- ☐ Increasing system size limit to 50 KW
- ☐ Other (please specify)

3. Please briefly provide an explanation of your position.

11. Screen #8: Single phase shared secondary (20% imbalance limit)

Present FERC SGIP Screen 2.2.1.8 "If the proposed Small Generating Facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer."

Argument for Keeping the FERC Screen 2.2.1.8 at present 20% nameplate rating of the service transformer

Existing state rules and utilities have commonly accepted FERC SGIP screen 2.2.1.8, for example:

THE NEW MEXICO INTERCONNECTION MANUAL , (page 10)

> "If the proposed Generating Facility is single-phase and is to be interconnected on a center tap of a 120/240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer."

Argument for Changing the FERC Screen 2.2.1.8 to 6 kVA of imbalance power

Imbalance – maximum of 6 kVA of imbalance between the two sides of a center-tapped 240-volt service. The 6 kVA limit for imbalances on single-phase 240-Volt services is to protect from excessive power imbalances causing overloading of the neutral conductor supplied by the utility. This neutral conductor, which mainly carries an amount of current similar to the difference in current between the two 240-Volt supply conductors is often undersized compared to either of the 240-Volt supply conductors. For instance, if one supply conductor is carrying 35 amps and the other supply conductor is carrying 25 amps, the neutral conductor would carry the difference, or approximately 10 amps. An imbalanced Generating Facility can increase the difference in current between the two supply conductors and thus increase the current carried by the neutral conductor.

California Rule 21 Southern California Edison Revised Cal., PUC Sheet No. 31574-E, Cancelling Revised Cal. PUC Sheet No. 30685-E, Rule 21, GENERATING FACILITY INTERCONNECTIONS

> "Single-Phase Generators: For single-phase Generators connected to a shared single-phase secondary system, the maximum Net Nameplate Rating of the Generating Facilities shall be 20 kVa. Generators connected to a centertapped neutral 240-volt service must be installed such that no more than 6 kVa of imbalanced power is applied to the two "legs" of the 240-volt service. For Dedicated Distribution Transformer services, the maximum Net Nameplate Rating of a single-phase Generating Facility shall be the transformer nameplate rating."

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*** 1. Do you support updating this screen?**

- ◯ YES
- ◯ NO
- ◯ I am not able to answer YES or NO because...

2. If you support updating this screen, what change would you recommend?

- ☐ Change limit to 6 kVA of imbalance power
- ☐ Other (please specify)

3. Please briefly provide an explanation of your position.

FERC-SGIP screens - Solar ABCs study

12. Screen #9: Size limit in an area where there are known stability limitation...

Present FERC SGIP Screen 2.2.1.9 The Small Generating Facility, in aggregate with other generation interconnected to the transmission side of a substation transformer feeding the circuit where the Small Generating Facility proposes to interconnect shall not exceed 10 MW in an area where there are known, or posted, transient stability limitations to generating units located in the general electrical vicinity (e.g., three or four transmission busses from the point of interconnection).

Argument for Keeping the FERC Screen 2.2.1.9 unchanged
Existing model rules and utilities have commonly accepted FERC SGIP screen 2.2.1.9, for example IREC Model Rule.

IREC Model Rule

> "The proposed generator, in aggregate with other generation interconnected to the distribution low-voltage side of the substation transformer feeding the distribution circuit where the generator proposes to interconnect, will not exceed 10 MW in an area where there are known or posted transient stability limitations to generating units located in the general electrical vicinity (e.g., three or four transmission voltage level busses from the Point of Common Coupling (PCC))."

Argument for Changing the FERC Screen 2.2.1.9 to restate the screen with detailing voltage stability requirements if appropriate

There are no known transient stability limits posted. The utilities have transmission path ratings which are voltage stability limits. We believe that this screen should be rewritten for voltage stability.

Abraham Ellis Sandia National Labs

> "I don't think WECC has any "stability areas" posted. However, the rating of all transmission paths and their respective limiting conditions are posted in the WECC path rating catalog. Most of the ratings are based on voltage stability."

Duquesne Light Company Transmission Planning Criteria

> "The PJM RTO established stability limits for preventing electrical separation of a generating unit or a portion of the PJM RTO. PJM recognizes three types of stability:
>
> - Steady State Stability – A gradual slow change to generation that is balanced by load.
> - Transient Stability – The ability of a generating unit or a group of generating units to maintain synchronism following a relatively severe and sudden system disturbance. The first few cycles are the most critical time period.
> - Dynamic Stability – The ability of a generating unit or a group of generating units to damp oscillations caused by relatively minor disturbances through the action of properly tuned control systems.

FERC-SGIP screens - Solar ABCs study

PJM will operate the facilities that are under PJM operational control such that the PJM system will maintain angular and voltage stability following any single facility malfunction or failure. In general, stability is not a limiting constraint on the PJM RTO."

*** 1. Do you support updating this screen?**

- ◯ YES
- ◯ NO
- ◯ I am not able to answer YES or NO because...

2. If you support updating this screen, what change would you recommend?

- ☐ Restating the screen with detailed voltage stability requirements
- ☐ Other (please specify)

3. Please briefly provide an explanation of your position.

FERC-SGIP screens - Solar ABCs study

13. Experience/Background questions

Please answer these background questions about your experience with interconnection and FERC SGIP screens.

*** 1. Which of the following best decribes your current role?**

- ◯ Utility - transmission focus
- ◯ Utility - distribution focus
- ◯ Utility - renewables focus
- ◯ Utility - policy focus
- ◯ Engineering firm
- ◯ Consultant
- ◯ Regulatory
- ◯ Manufacturer
- ◯ Other (please specify)

2. In which state or states has the bulk of your recent renewables related interconnection work been focused?

	#1	#2	#3	#4	#5	#6	#7	
State:								

*** 3. Briefly explain your experience (engineering or policy) with the interconnection of PV systems.**

*** 4. Explain your experience with the FERC SGIP screens.**

5. What do you think needs to be done next with the FERC SGIP screens?

FERC-SGIP screens - Solar ABCs study

14. Thank you for your time and effort.

You may click the "previous page" button below to revisit any of the questions. If you are satisfied with your answers click "Done."

Thank you again for your time and effort. You will be receiving a summary of the questionnaire results as soon as they are compiled. You will also receive a copy of the final report as soon as it is published.

If you have questions or comments please contact:

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