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BORREGO SPRINGS MICROGRID DEMONSTRATION PROJECT

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Final Technical Report

Submitted By:

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List of Acronyms and Abbreviations

AC	Alternating Current	LMP	Locational Marginal Pricing
AES	Advanced Energy Storage	M&V	Measurement and Verification
AMI	Automated Metering Infrastructure	MDMS	Meter Data Management System
C&I	Commercial and Industrial	MMC	Microgrid Master Controller
CAISO	California Independent System Operator	MW	Megawatt
CB	Circuit Breaker	NOAA	National Oceanic and Atmospheric Administration
CBA	Cost Benefit Analysis	NOC	Network Operations Center
CBL	Customer Baseline Load	NPV	Net Present Value
CEC	California Energy Commission	O	Other
CES	Community Energy Storage	O&M	Operations and Maintenance
CO	Constant Output	OASIS	Open Access Same-time Information System
DEM	Distributed Energy Manager	OMS	Outage Management System
DER	Distributed Energy Resources	OpEx	Operational Excellence
DG	Distributed Generation	PCS	Power Conversion System
DMS	Distribution Management System	PCT	Programmable Communicating Thermostat
DNP	Distributed Network Protocol	PDLM	Price Driven Load Management
DOE	Department of Energy	PIER	Public Interest Energy Research
DR	Demand Response	PLC	Programmable Logic Controller
EOC	End of Circuit	PQ	Power Quality
FAST	Feeder Automation System Technology	PS	Peak Shaving
FLISR	Fault Location Isolation and Service Restoration	PV	Photovoltaic
HAN	Home Area Network	RDO	Real Device Outage
HHV	Higher Heating Value	RES	Residential Energy Storage
HPV	High Penetration Photovoltaic	RFP	Request for Proposal
IHD	In Home Display	RTP	Real Time Pricing
ITC	Investment Tax Credit	SCADA	Supervisory Control and Data Acquisition
kBTU	Kilo British Thermal Unit	SDG&E	San Diego Gas and Electric
kVAr	Kilo Volt Ampere Reactive	SES	Substation Energy Storage
kW	Kilowatt	SOC	State of Charge
kWh	Kilowatt-Hour	US	United States
LCS	Load Control Switch	VAr	Volt Amp Reactive
LF	Load Following	WP	Weak Point

Acknowledgements

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Partners

- US Department of Energy
- California Energy Commission
- San Diego Gas and Electric

Vendors:

- Horizon Energy Group
- Saft with Parker Hannifin
- Lockheed Martin
- Hawthorne Power Systems

1 Executive Summary

SDG&E has been developing and implementing the foundation for its Smart Grid platform for three decades – beginning with its innovations in automation and control technologies in the 1980s and 1990s, through its most recent Smart Meter deployment and re-engineering of operational processes enabled by new software applications in its OpEx 20/20 (Operational Excellence with a 20/20 Vision) program. SDG&E's Smart Grid deployment efforts have been consistently acknowledged by industry observers. SDG&E's commitment and progress has been recognized by IDC Energy Insights and *Intelligent Utility Magazine* as the nation's "Most Intelligent Utility" for three consecutive years, winning this award each year since its inception. SDG&E also received the "Top Ten Utility" award for excellence in Smart Grid development from GreenTech Media.

This demonstration project brings circuit and customer realities to the picture. While a few Microgrid trials have taken place in the US, they have typically been of a smaller scale and not directly applicable to the real operating environment. This project differs from previous efforts and has extended the knowledge base as follows:

- The Microgrid supported actual customers in a real operating environment
- The project is at significant scale (4MW)
- The Microgrid design incorporates both reliability and economic oriented operations
- Microgrid operations investigate the technical and economic interactions of multiple resources
- The project investigates the ability to use pricing signals to guide operations

The Project focused on the design, installation, and operation of a community scale "proof-of-concept" Microgrid demonstration. The site of the Microgrid was an existing utility circuit that had a peak load of 4.6 MW serving 615 customers in a remote area of the service territory. The project focused on the installation, integration and operation of the following key technologies:

- Distributed Energy Resources (Diesel Generators)
- Advanced Energy Storage
- Feeder Automation System Technologies
- Price Driven Load Management
- Integration with OMS/DMS and Microgrid Controls

The overall objectives for the Microgrid Demonstration Project were to:

1. Demonstrate the ability to achieve a 15% or greater reduction in feeder peak load
2. Demonstrate capability of reactive power management
3. Develop a strategy and demonstration of information integration focused on both security and overall system architecture
4. Develop a strategy and demonstrate the integration of AMI into Microgrid operations

5. Develop a strategy and demonstrate ‘self-healing’ networks through the integration of Feeder Automation System Technologies (FAST) into Microgrid operations
6. Develop a strategy and demonstrate the integration of an Outage Management System/Distribution Management System (OMS/DMS) into Microgrid operations
7. Demonstrate the capability to use automated distribution control to intentionally island customers in response to system problems
8. Develop information/tools addressing the impact of multiple DER technologies

The project was unique in that the it was funded by the US Department of Energy (DOE), the California Energy Commission (CEC), San Diego Gas and Electric (SDG&E), and the project partners. There were two DOE funded activities that included the overall Microgrid Project and then the inclusion of Community Energy Storage (CES) systems integrated into the Microgrid. The CEC portion of the project addressed the customer-side of the meter resources related to the Price Driven Load Management that consisted of the software cost, software installation, home area network equipment cost, and installation in customer homes.

The project was conducted in three phases:

- Phase 1: Baseline and Key Developments
- Phase 2: Integration and Operational Testing
- Phase 3: Data Collection and Analysis

The Phase 2 activities were carried out in an incremental fashion where a technology was installed and operated to quantify its contribution to the Microgrid before the next technology was added. Operations were conducted for each technology in a stand-alone basis and then in combination with the other installed resources. Once all the resources were installed and the stand-alone operations evaluated, demonstrations of Optimized operations were conducted. The key elements of the Microgrid resources implemented for the project were:

- Two 1,800 kW Diesel Generators
- One 500 kW / 1,500 kWh lithium ion energy storage unit
- A Fault Location, Isolation and Service Restoration system
- An automated demand response system with pricing based event capabilities
- A Microgrid Visualizer to support control and monitoring of the Microgrid resources

Diesel Generator Demonstrations

The key findings from this demonstration that lay a foundation for feeder optimization are:

- The generators were able to operate in both constant output and load following modes
- The generators were capable of operation using both local controls and remote control through the Microgrid Visualizer
- The generators were capable of operation individually and in conjunction with each other
- The generators were capable of limiting the load at the Microgrid Circuit Breaker when operated in the load following mode

- At certain times, the generators were capable of carrying the entire Microgrid Circuit load (demonstrated by the zero flow at the breaker demonstrations)
- The utility was able to develop and successfully execute a procedure between the Microgrid Operator and Distribution System Operator to engage the operation of the generators on the circuit on a routine basis
- In planned operations, the generators could be started, warmed up, synchronized to the grid, and operated at the desired set point in approximately 10 minutes
- The generators operated very close to the manufacturer's performance curve

Fault Location, Isolation and Service Restoration (FLISR) System Demonstrations

The FLISR demonstrations were conducted as simulations using the new outage management system and distribution management system (OMS/DMS). The simulations validated the control algorithms and the ability of the system to present the correct switching plans to the distribution operators. The simulation validated that the use of FLISR can result in the distribution operators being able to address faults and restore the maximum number of customer within a period of five minutes. This means that many outages can be managed so that a minimum number of customers experience a momentary outage instead of a longer sustained outage.

Energy Storage System Demonstrations

The key findings from this demonstration that lay a foundation for feeder optimization are:

- The energy storage system was able to operate in both constant output and load following modes
- The energy storage system was capable of operation using both local controls and remote control through the Microgrid Visualizer
- The energy storage system was capable of limiting the load at the Microgrid Circuit Breaker when operated in the load following mode
- The utility was able to develop and successfully execute a procedure between the Microgrid Operator and Distribution System Operator to engage the operation of the energy storage system on the circuit on a routine basis
- The energy storage system efficiency and capacity were near the manufacturer's performance specifications. The demonstrated performance was a round trip efficiency of 87.1% and a total storage capacity was 1,718 kWh.
- VAr demonstrations showed that the energy storage system is able to control the reactive power at the circuit breaker in a manner similar to a variable capacitor
- The energy storage system is capable of four quadrant operation

Price-Driven Load Management (PDLM) Demonstrations

The Price-Driven Load Management system was used for managing customer load on the Microgrid. The PDLM system was interfaced with SDG&E's newly deployed advanced metering infrastructure system and included Home Area Network (HAN) systems, and the PDLM controller. Customer-side technologies that integrate into the PDLM system are:

- Programmable Communicating Thermostats
- Load Control Switches
- Plug Load Controllers
- In-Home Displays
- Customer Web Portal

The PDLM controller is the system of record to forecast Demand Response (DR) capacity and schedule DR events to meet the load reduction objectives within the Microgrid.

A major objective of the demonstration project was to discover how the PDLM resources could be managed in the Microgrid environment and if PDLM could be managed like the other DER resources. Ideally, PDLM could be managed in the Microgrid the way that generators or storage systems are managed.

The PDLM system is limited and constrained by the capacity to deliver load reduction depends on weather, time of day, and customer behavior. Agreements with customers limited the frequency and duration of PDLM events during the demonstration. Customers also had the option to opt-out of events. One of the methods employed for the demonstration to help manage Microgrid resources was to have the PDLM system forecast the demand reduction capacity on an hourly day-ahead basis. The forecasts that were developed were not as accurate as needed and the approach for improving the forecast required many iterations of events which were limited.

Taken together, PDLM is very different from the other DER resources in the Microgrid. While it can be dispatched as part of the overall Microgrid Optimized plan, benefiting from PDLM requires a wider variety of operational considerations and is far less reliable and predictable than other resources in its current design.

Microgrid Island Demonstrations

One of the highlights of the Demonstration project was the ability to effectively island the entire Microgrid supporting more than 600 customers. The islanding demonstrations transitioned into and out of the island mode without affecting the quality of service to the customers (seamless transitions without an outage or flicker). The island demonstrations evaluated the island operations with the DG units only, the DG units operating with the SES in both charge and discharge modes, and the DG units operating with the SES unit providing a majority of the reactive power requirements. All demonstrations were successful and fulfilled the stated operational objectives.

Additionally, the Microgrid was operated in island operation twice during the demonstration period to provide service to customers who would have otherwise had an extend loss of service.

One event occurred for a planned upgrade to the substation to accommodate the connection of a 26 MW PV system. The other event was during an unplanned outage that was caused by bad weather. In both instances the Microgrid substation configuration was changed to successfully island over 1000 customers.

Cost Benefit and Future Deployments

The lessons learned and the quantified benefits from the Microgrid demonstration were used to identify other potential cost effective Microgrid applications in the SDG&E service territory. Applications were identified where there is a high potential to improve existing distribution operations (i.e. highest benefit potential) and classified as follows:

- Large commercial and industrial customers
- Communities with challenges due to a high penetration of solar PV
- Weak points in the distribution network
- End of circuit
- Other

The key findings from the cost benefit analysis are that potential deployment of cost-effective Microgrids and DER are not as broad and deep as expected. A total of 28 cost-effective applications were identified for further consideration in the service territory:

- 10 MW Microgrid: quantity = 2
- 1 MW Microgrid: quantity = 10
- 300 kW DER solutions: quantity = 18

Please Note: The Borrego Springs Microgrid Demonstration Project was done in conjunction with work funded by the California Energy Commission (CEC). For additional information and findings, please refer to the PIER Final Project Report entitled Borrego Springs Microgrid Demonstration Project - CEC-500-08-025.

2 Introduction

The foundation of existing electric utility systems is based on delivering power from central station generation units to a diverse group of end users. Market, technological, and regulatory forces have created a nexus of opportunity to leverage distributed resources in the delivery of highly reliable and cost effective electricity through a Smart Grid alternative service delivery model (Microgrid). At the same time, customers are also investigating and investing in energy assets and distribution systems for their facilities ranging from backup power systems to on-site generation to renewable energy resources. While some progress has been made on the development of interconnected loads and distributed energy resources there has been scant attention to the development of an integrated energy system that can operate in parallel with the grid or in an intentional island model. Hence, there a critical need to understand how Microgrids consisting of interconnected loads and distributed energy resources can be operationally optimized and developed in a cost effective manner. Concurrently, there is an increasing need to assess the role, impact, and contributions of sustainable communities in integrated Microgrid designs and their potential to contribute to demand response objectives and programs.

San Diego Gas and Electric (SDG&E) embarked on The Borrego Springs Microgrid Demonstration Project to design and implement an innovative Microgrid that integrates the electrical distribution network, distributed energy resources and resources on the customer-side of the meter. The design focused on the ability to optimize assets, manage costs, and increase reliability. Enabling technologies to be integrated in the Microgrid included automated demand response, distributed generation, advanced energy storage, and outage management technologies. This demonstration project also lays the framework for assessing cost versus benefits and the impact and viability of Microgrids on energy costs and price volatility.

The project brings circuit and customer realities to the picture. While a few Microgrid trials have taken place in the US, they have been small scale and not directly applicable to the real operating environment. This project differs from previous efforts and has extended the knowledge base as follows:

- The Microgrid supported actual customers in a real utility operating environment
- The project is at significant scale (4 MW)
- The Microgrid design incorporates both reliability and economic oriented operations
- Microgrid operations investigate the technical and economic interactions of multiple resources
- The project investigates the ability to use pricing signals to guide operations

The project was designed to operate at a real world scale with more than 600 actual customers, and was affected by operations such as outage, transient, and event conditions. The project provided knowledge about the design, operational, and economic considerations of an integrated Microgrid system. The successful and optimized integration of distributed energy technologies not only rests with their functionality and ability to address outages and event conditions, but also the economics of Microgrids.

The design and implementation of the Microgrid also meant the involvement of a large cross section of departments and personnel at SDG&E. This included personnel from Asset Management, Transmission and Distribution System Operations, Customer Programs, Regulatory, Research and Development, Emerging Technologies, and Information Technology and Security. This demonstration provided in depth experience to SDG&E personnel and stakeholders alike, on the scale of resources that are required to implement Microgrids that affect real customers and electric operations.

This project consisted of several team members and was funded by a United States Department of Energy (DOE) Renewable and Distributed Systems Integration grant, a California Energy Commission's PIER grant and cost share by SDG&E and other project team members provided the remaining funds for the demonstration. The CEC PIER portion of the project focused on the integration of resources on the customer-side of the meter and evaluated their contribution to Microgrid operations.

Section 3 of this report presents the overall objectives that were achieved for the Microgrid Demonstration. Section 4 presents the phased approach that was developed to integrate the various technologies and strategies. Section 5 provides a summary of the key findings based on the project objectives. Section 6 presents the Microgrid deployment scenario within the SDG&E service territory. Lessons Learned and Key Findings are presented in Section 7.

3 Objectives

The Project consisted of a full scale "proof-of-concept" demonstration of a Microgrid on an existing utility circuit that had a peak load of 4.6 MW serving 615 customers in a remote area of the service territory. The project focused on the installation, integration and operation of the following key technologies:

- Distributed Energy Resources (Diesel Generators)
- Advanced Energy Storage
- Feeder Automation System Technologies
- Price Driven Load Management
- Integration with OMS/DMS
- Microgrid Controller

The overall objectives for the Microgrid Demonstration Project were to:

1. Demonstrate the ability to achieve a 15% or greater reduction in feeder peak load through the integration of multiple, integrated DER – distributed generation (DG), electric energy storage, and price driven load management on a San Diego Gas and Electric Company feeder
2. Demonstrate capability of Volt-Amps-Reactive (VAr) electric power management - coordinating the DER with existing VAr management/compensation tools
3. Develop a strategy and demonstration of information integration focused on both security and overall system architecture
4. Develop a strategy and demonstrate the integration of AMI into Microgrid operations
5. Develop a strategy and demonstrate 'self-healing' networks through the integration of Feeder Automation System Technologies (FAST) into Microgrid operations
6. Develop a strategy and demonstrate the integration of an Outage Management System/Distribution Management System (OMS/DMS) into Microgrid operations
7. Demonstrate the capability to use automated distribution control to intentionally island customers in response to system problems
8. Develop information/tools addressing the impact of multiple DER technologies including:
    - Control algorithms for autonomous DER operations/automation that address multiple DER interactions and stability issues
    - Penetration limits of DER on the substation/feeder
    - Coordination and interoperability of multiple DER technologies with multiple applications/customers.

4 Approach

The project plan was organized into three phases:

- Phase 1: Baseline and Key Developments
- Phase 2: Integration and Operational Testing
- Phase 3: Data Collection and Analysis

Table 1 presents the phased approach that was developed to integrate the various technologies and strategies and provides an outline of the tasks associated with each Phase of the project.

Table 1: Microgrid Demonstration Phased Approach

Phase	Task
Phase 1 -Establishment of Baseline and Key Developments	Task 1B --Site Selection
	Task 2.1 -- Pilot Network Analysis and Baselining
	Task 2.2 -- Key Developments
Phase 2 – Integration of Technologies and Operational Testing	Task 3.1 -- Integration of Existing Distributed Energy Resources and VAr Compensation
	Task 3.2 -- Stage 1 Distributed Systems Integration (DSI) Testing
	Task 3.3 -- Integration of Feeder Automation System Technology
	Task 3.4 -- Stage 2 Distributed Systems Integration Testing
	Task 3.5 -- Integration of Advanced Energy Storage
	Task 3.6 -- Stage 3 Distributed Systems Integration Testing
	Task 3.7 -- Integration of Outage Management System/Distribution Management System (OMS/DMS) for Microgrid Operations
	Task 3.8 -- Stage 4 Distributed Systems Integration Testing
	Task 3.9 -- Integration of Price-Driven Load Management
	Task 3.10 -- Stage 5 Distributed Systems Integration Testing
	Task 3.11 -- Feeder Optimization Scenario Testing
Phase 3 – Data Collection and Analysis	Task 5.1 -- Cost / Benefit Analysis for Large-Scale Deployment
	Task 5.2 -- Implementation Plan for Large-Scale Deployment

4.1 Phase 1 - Establishment of Baseline and Key Developments

Phase 1 of the project involved establishing a baseline for a selected circuit within the service territory. A substation was selected after performing a detailed site selection process. A network analysis was performed on the selected circuit to collect historical data to establish the baseline operational performance characteristics of the associated substation and selected circuit in terms of key metrics such as load profiles and reliability metrics. This data served as the basis for developing specific strategies of equipment sizing, interface requirements, operating scenarios, and created a foundation to measure the anticipated impacts of the various Microgrid Resources. Key developments for the Project included a comprehensive set of Use Cases that were used to identify departments within the utility that would need to be involved in the Project, the anticipated sequence of operations, technology functional requirements, communication requirements, and cyber security considerations. This process was key to the project as this foundation was used as a source for the development of Request For Proposals for the Microgrid Resources including the, generator control upgrade, advanced energy storage, the Price Driven Load Management System, and the Microgrid Controller.

Task 1B - Site Selection

The process of site selection was based on criteria that addresses substation, circuit and customer attributes. The site selection team evaluated 18 substations using an evaluation matrix that addressed the following factors with an emphasis on meeting project goals and improving reliability:

- Permitting requirements
- Level of AMI penetration
- Level of customer-owned renewable resources
- Environmental requirements
- Communications environment
- Existing customer-owned non-renewable generation resources
- Anticipated community acceptance of the Microgrid project
- Potential customer participation in Energy Efficiency and DR programs
- Potential distribution system impacts on peak load and reliability
- Transmission system impacts on peak load, reliability, and congestion pricing

A circuit served by the Borrego Substation was selected as the Microgrid Circuit due to the following characteristics:

- Relatively high penetration of customer-owned PV
- Potential for improvement in reliability
- Availability of land adjacent to the substation
- Reasonable peak load in the circuit (4.6 MW)
- Remote location
- Few customers near the substation
- Mostly residential customers on circuit

Some challenges that the Borrego substation presented include:

- No AMI infrastructure (at the time of selection)
- Substation located in a 100 year flood plain
- Need to work with the community to gain acceptance
- Remote area
- Potential communication issues
- No natural gas infrastructure

- Population fluctuates with the seasons (higher in the winter and lower in the summer)
- Desert climate (summer high temperatures greater than 110 ^{o}F)

The Borrego substation is located at the end of a single radial 69 kV transmission line. At the substation, the voltage is stepped down to 12 kV and serves three radial distribution circuits.

Task 2.1 - Pilot Network Analysis and Baselining

A performance baseline was established by identifying and collecting key Microgrid Circuit metrics. This baseline provided the basis for comparison with the data collected during the demonstrations. The existing system infrastructure on the Microgrid Circuit included the following devices:

- SCADA enabled switches
- Voltage Regulators
- Capacitors
- Microwave Communication System

Historical data on the Microgrid Circuit was analyzed to develop daily load profiles for each year during the period between 2007 and 2009. Table 2 and Figure 1 present a summary of the monthly peak demand for the Microgrid Circuit. The data shows a trend with higher peak demand in the summer with an average peak of 4.3 MW. The highest peak of 4.6 MW occurred in August 2009. The lack of significant yearly variability is due to the significant population swings.

Table 2: Microgrid Circuit Historical Monthly Peak Demand

Month	2007	2008	2009	Average
Jan	4.12	3.38	4.21	3.90
Feb	3.58	3.29	3.50	3.46
Mar	3.75	3.48	3.70	3.64
Apr	3.7	3.62	3.54	3.62
May	4.03	3.76	3.89	3.89
Jun	4.11	3.98	4.08	4.06
Jul	4.32	4.22	4.48	4.34
Aug	4.12	4.1	4.63	4.28
Sep	3.84	3.86	4.48	4.06
Oct	3.05	3.69	3.94	3.56
Nov	2.63	3.59	3.23	3.15
Dec	3.45	3.45	2.66	3.19
Max	**4.32**	**4.22**	**4.63**	**4.34**

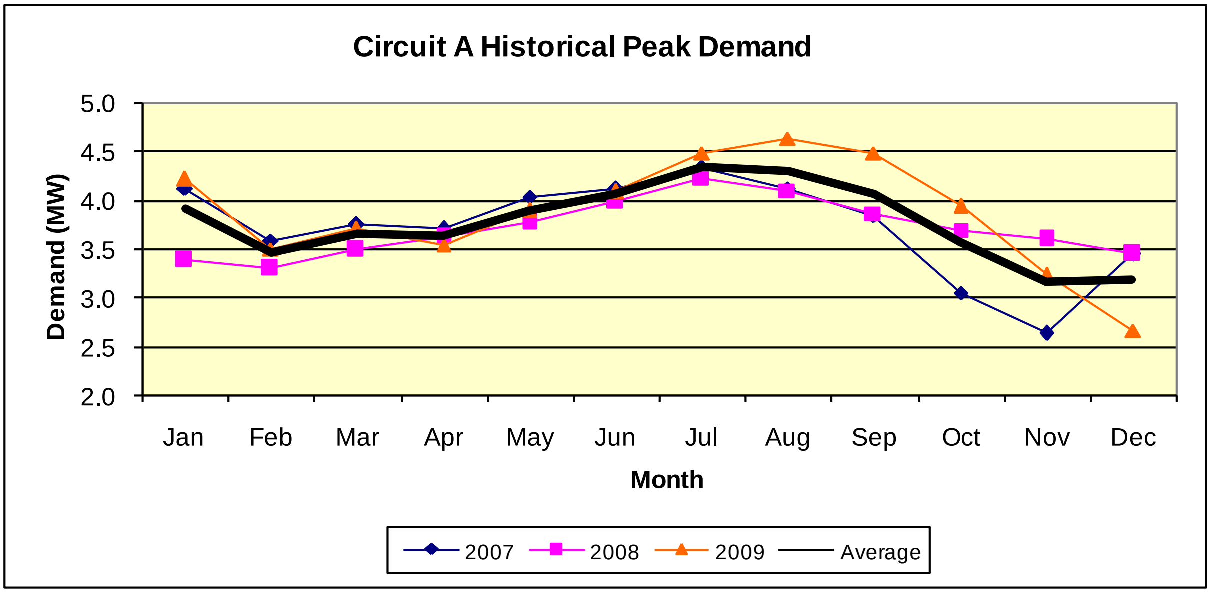


Figure 1: Microgrid Circuit Historical Monthly Peak Demand

Hourly data was analyzed to gain a better understanding of the load characteristics on the Microgrid Circuit. Figure 2 presents the hour summer day profiles for July 2009 with each line representing a day of the month. This data shows that the circuit has a unique load profile in that the day-time load is low and the circuit peak load occurs at night. The high night time load is because of the use of water pumps by the local water district and irrigation pumps by agriculture customers on the circuit. These customers are on a time-of-use tariff where the demand charges and energy rates are lower during the night.

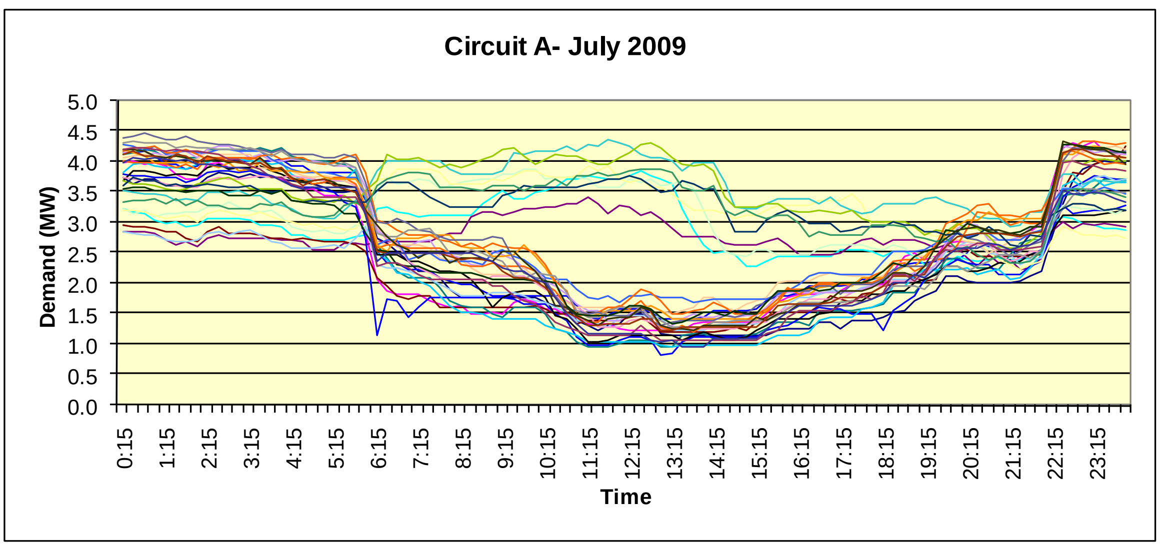


Figure 2: Summary Hourly Load Profiles for the Month of July 2009

There are a total of 26 customer-owned PV systems on Microgrid Circuit with a total installed inverter capacity of 597 kW. The system sizes range from 225 kW down to 2 kW. There are two 225 kW customer-owned systems on the circuit. Detailed analysis was performed to estimate the annual electric production for the PV systems on the Microgrid Circuit.

Figure 3 presents a graph of the daily AC output of the aggregated PV systems on the Microgrid Circuit for a typical summer month of July. Daily PV load profiles are presented in different colors for each day of the month.

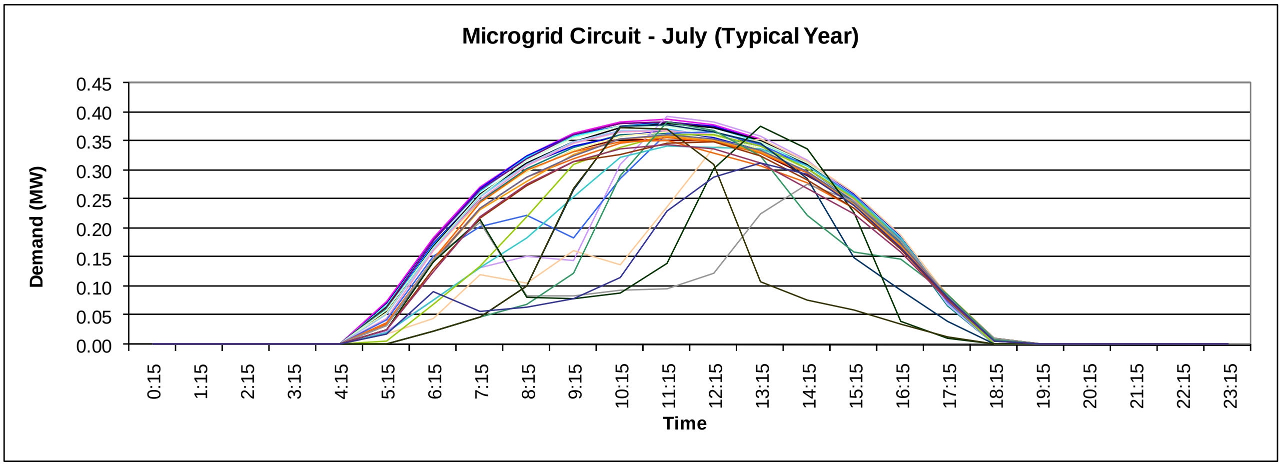


Figure 3: Aggregated Daily AC Output for the Microgrid Circuit PV Systems - July (Typical Year)

Operation of the Microgrid Resources needs to be able to address the intermittency of this PV generation.

Task 2.2 – Key Developments

Use cases were developed with a group of stakeholders that included subject matter experts from numerous SDG&E departments, vendors, and project partners. These use cases captured various scenarios for operation and control of the distributed energy resources within the Microgrid. In all, ten Use Cases were identified and many had more than one scenario that was analyzed and documented. A summary of the Use Cases and scenarios are as follows:

Use Case 1: Utility Manages Utility-Owned Distributed Generation

- Scenario 1: Utility uses communications infrastructure to communicate with utility-owned distributed generation to start/stop generator in constant output mode.

Use Case 2: Real-time VAR Support

- Scenario 1: Capacitor reads Circuit VAr data real time and automatically turns on or off based upon prearranged setting. Change in status reported to DMS through SCADA.
- Scenario 2: Capacitor reads line voltage and relays it to DMS through SCADA.
- Scenario 3: Distribution operator places capacitor in Manual mode and manually turns capacitor on or off and Microgrid Master Controller (MMC) re-optimizes.

Use Case 3: FAST

- Scenario 1: Microgrid in island operation, a fault occurs inside Microgrid.

- Scenario 2: Microgrid in island operation on DG only, a fault occurs inside Microgrid.
- Scenario 3: Microgrid in island operation on AES with DG available, a fault occurs inside Microgrid.
- Scenario 4: Capacitor automatically comes online or offline as a result of FAST operation.

Use Case 4: Independent Energy Storage Operations

- Scenario 1: Energy storage executes charge/discharge sequence independent of DMS and MMC control as part of ongoing Peak Shaving Operations (similar to Capacitor Bank operations)
- Scenario 2: Energy storage executes charge/discharge sequence in response to over voltage or under voltage on circuit (load-following mode)

Use Case 5: Directed Energy Storage Operations

- Scenario 1: Energy storage executes basic charge/discharge sequence due to command from DMS/MMC
- Scenario 2: Energy Storage executes change in VAr flow during charge/discharge operations due to request from DMS/MMC. SCADA capacitor detects change in VAr status and reacts accordingly
- Scenario 3: Utility uses energy storage for energy arbitrage (financial)

Use Case 6: MMC monitors grid system status and exerts control to maintain system stability and prevent overloads

- Scenario 1: MMC detects line outage, arms appropriate response, and executes
- Scenario 2: Microgrid executes a planned transition to island operation
- Scenario 3: Microgrid reconnects to the main grid
- Scenario 4: MMC controls individual Microgrid resources

Use Case 7: MMC monitors grid system status and passes information along to DMS

- Scenario 1: MMC incorporates all system information into a status evaluation

Use Case 8: MMC curtails customer load for grid management due to forecast

- Scenario 1: Forecast load expected to be subject to curtailment and pass to DMS
- Scenario 2: Execute curtailment in response to pre-scheduled pricing event on system
- Scenario 3: Customer opts out of curtailment for pre-scheduled event
- Scenario 4: Load at the customer site is already below threshold
- Scenario 5: Forecast DR event incorporating 3rd party aggregators with localized control and measurement capabilities

Use Case 9: MMC curtails customer load for grid management due to unforeseen events

- Scenario 1: Execute emergency curtailment in response to load on system

- Scenario 2: Customer opts out of curtailment for Grid Management (same as scenario 1)
- Scenario 3: Customer already operating at DR commitment level (same as scenario 1)

Use Case 10: Planners Perform Analyses Using Multiple Data Sources

- Scenario 1: Planners perform studies with data from a designated subset of meters

Microgrid Design - The Microgrid conceptual design was created from the use case requirements that include the objective of managing peak load on the Microgrid Circuit to improve reliability and circuit operation. Design discussions were conducted to develop an operational methodology for design and integration of the Microgrid Resources in two major modes:

Normal mode (grid-connected) - In this mode of operation, the Microgrid Resources support the electric service provided by the grid. These resources are managed to achieve the following operational objectives:

- Peak Demand Reduction
- Reliability
- Economics
- Environmental Factors

Island Operation - In this mode of operation, the Microgrid is isolated from the grid and the Microgrid Resources are managed to ensure a balance between generation and load. Two approaches to the Microgrid island mode of operation were evaluated:

- Planned Island: The planned Island would occur during a planned outage of the circuit or for transmission line maintenance or upgrades.
- Unplanned Island: The unplanned Island would occur after a fault that results in an extended outage. To operate in the unplanned island, a sequence of operation was developed to sectionalize the circuit for load management, cold start of the generator units, forecast of system load, and restoration of the customers within the Microgrid.

In both approaches to Island Operation, the Microgrid generation resources need to have the capability to synchronize back to the grid in a managed transition once the service to the Microgrid Circuit is restored.

Control Methodology - Both a centralized control methodology and a distributed control methodology were considered. A distributed level of control has been successfully applied to managing operations of the main grid. This same method was used as a starting point for evaluating the best control methodology for the Microgrid.

Centralized Control - All control actions for the Microgrid would be centralized under the Microgrid Controller as a component of the Distribution Management System (DMS). A centralized control methodology simplifies Microgrid operations and its integration with other distribution systems and processes. However, this was deemed impractical for a number of reasons:

- Centralized control is not feasible due to the rapid response needed to address expected transients in real time
- Centralized control is the control method of choice only for non-critical applications that can be applied over many seconds to minutes
- Centralized control is vulnerable to single points of failure in communication or even loss of Microgrid Controller functionality
- Communications require very high speed, low latency, and extremely high reliability to support the real time response to transients required by Microgrid resources

Distributed Control- It is a combination of centralized control and decentralized control. In this model, the Microgrid Controller is responsible for dispatching Microgrid Resources and high level data collection and analysis. This model is similar to the approach used for the utility distribution operations with some exceptions:

- In parallel operation, the main grid maintains system frequency within limits. The main grid responds to Microgrid transients without action from the Microgrid control systems. Power quality (PQ) and voltage are exceptions. Local controls at the Microgrid resources adjust voltage regulators and inverters to achieve PQ and voltage set points. Centralized control from the Microgrid Controller adjusts set points of the Microgrid resources over a longer timeframe to optimize the performance.
- In island mode, the inertial response provided by the main grid is not available. The Microgrid is more sensitive to upsets and transients. Decentralized local controls at the Microgrid resources are useful in responding to changes in frequency and voltage. This action is analogous to the action provided by governor and voltage regulators at power plants connected to the main grid. The primary objective is reliability, stability and PQ within limits. Secondary objectives are efficiency, economics, and environmental metrics.

The Microgrid Controller provides centralized control in parallel and island modes of Microgrid operation. It operates over a longer time horizon and dispatches Microgrid Resources by adjusting operating set points to achieve operating and optimization objectives. The Microgrid Resources have their own local controls for distributed control including system operation and protection. These specific systems provide for individual control to turn the equipment on and off, set the mode of operation, accept changes to operating set points, and trigger operational events.

4.2 Phase 2 - Integration of Technologies and Operational Testing

Task 3.1 – Integration of Existing Distributed Energy Resources and VAr Compensation

Two Caterpillar XQ-2000 Power Modules with CAT 3516TA Diesel Engine Generators were used as the Distributed Generation (DG) component of the Microgrid as shown in Figure 4. Each generator has a nominal generation capacity of 1,800 kW.

Figure 4: Microgrid Distributed Generators

These units can be controlled locally at the substation or using a secure remote interface. The DG units can operate in the following modes of operation:

- Base Load (Constant Output) – This operational mode of the generator(s) is applicable when the generator(s) are running in parallel with the main grid. The generator(s) in base-load operates at set points to produce real power (kW) at a given power factor setting.
- Import Control (Peak Shaving) – This operational mode of the generator(s) is applicable when the generator(s) are running in parallel with the main grid. In this mode, the generators maintain power flow (kW) through the Microgrid Circuit breaker at or below the specified Import Control set point.
- Island Operating Mode – In this operational mode, the generator(s) are loaded to meet the demand (kW) on the Microgrid Circuit. The generator controller manages the frequency and reactive power of the circuit.

DG Operational Constraints - The individual DG unit operating hours are restricted to 8 hours per day and 200 hours per year by permits from the San Diego Air Pollution Control District (SDAPCD).

DG Heat Rate & Economic Cost Calculation - Heat Rate (kBTU/kWh) is the primary metric for assessing the economics of generator operation on the basis of operational efficiency. Performance data (heat rate and operational cost) from the generator manufacturer is presented in Figure 5. It is based on a cost of $4.00/gallon for Ultra-Low-Sulfur Diesel and a diesel Higher Heating Value (HHV) of 128,000 BTU/gallon.

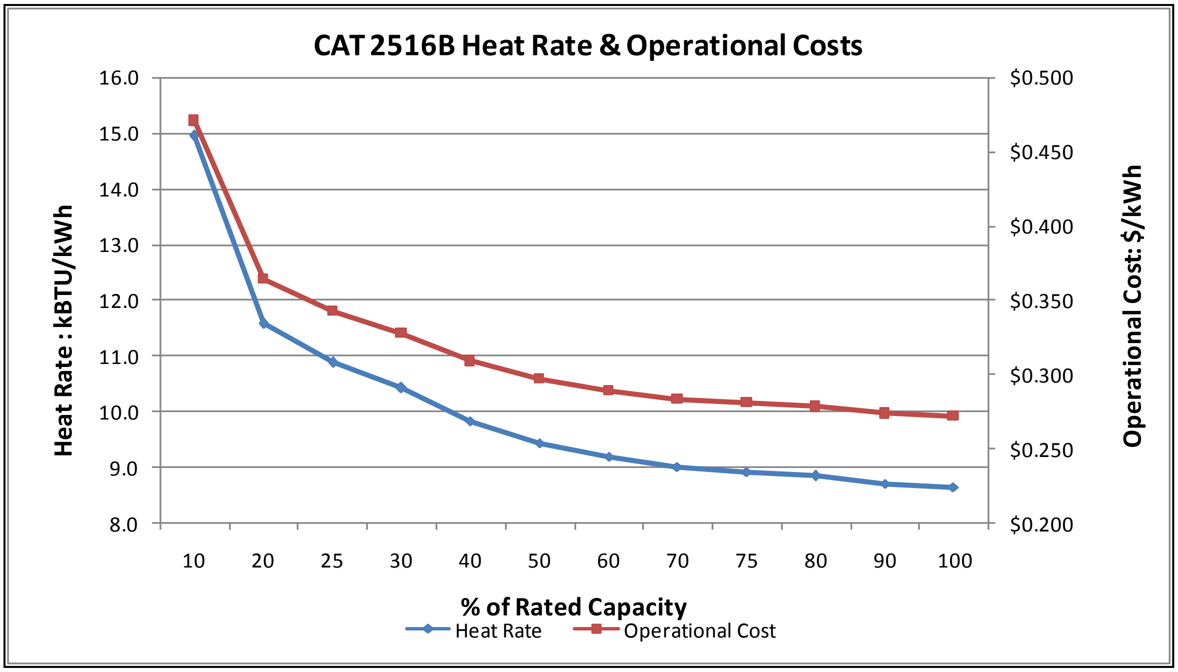


Figure 5: Baseline DG Heat Rate and Operational Cost

SCADA Integration and Protection System – The utility SCADA system was utilized to provide coordinated operation of existing switches and breakers within and at the boundary of the Microgrid Circuit. To maintain continuity with existing operations, the generator breaker protection was integrated into the existing SCADA system via fiber-optic communications between the generator breaker protection relays and the protection relay on the Microgrid Circuit main breaker. The following SCADA commands were used to manage the switching actions to transition the Microgrid between its various operating states.

- Parallel Command - Enables a synchronized-check across the generator breaker, allowing it to close when the generator output has matched frequency, voltage, and phase angle with the Microgrid Circuit and connected substation.
- Normal Command (Break Parallel) - This command forces the DG units to disconnect (“break-parallel”) from the substation leaving the Microgrid Circuit supplied by only the transmission network.
- Island Command - Enables the generators to pick up the entire load of the Microgrid Circuit. The generators operate to drive power flow to zero across the substation breaker. When this is accomplished, the Microgrid Circuit main breaker is opened and the Microgrid is separated from the substation and operating as an Island.
- Black-Start Command - This command (in the event of complete loss of power to the substation) enables a substation dead-bus check by the protection relay on the Microgrid main breaker and opens the Microgrid main breaker. Further it facilitates the closing of the generators into the dead bus, energizing the Microgrid Circuit in an Island operating state.

The DG controller's operational mode selection, set points, and operational status are accessible from a remote Microgrid Visualizer via secure communications. On the network communication path, a dedicated Microgrid gateway was provided to the interface point for the generator controllers. Network communications between the generator controllers and the gateway use Modbus-IP protocol. Network communications between the Microgrid gateway and back-office systems occurs via Distributed Network Protocol (DNP3).

Task 3.2 – Stage 1 Distributed Systems Integration (DSI) Testing

This task demonstrated the testing of the DG units on the Microgrid Circuit. The objective of these demonstrations was to quantify the contributions of the DER and VAr compensation components to the Microgrid. A component of the task was to compare the results from DG operation to the baseline to determine relative improvements consistent with the objectives of the Project. In addition, data collected from the demonstrations was used to validate the operational efficiency of the units under varying load conditions and to compare actual efficiency to the manufacturer's published performance curves.

Four types of standalone generator demonstrations were conducted:

- Constant Output - The constant output mode operation represents the most basic operation of the generators and was used to get the operators acquainted with the steps required to operate the equipment as well as learn how the generators respond to the given commands. These demonstrations established the interface and coordination with the Distribution Operators who provided the permissions and required switching operations for the generators to synchronize with the Microgrid Circuit.
- Peak Shave - The Peak Shave Mode represents one of the key modes of operation for the generators in the Microgrid as it is the mode that will be required to meet the 15% peak load reduction goal for the project. In the Peak Shave Mode, the generators monitor the load at the Microgrid Circuit Breaker and supply the electricity required by the Microgrid Circuit load that is in excess of the Microgrid Circuit Breaker Load Set point. The primary objective of the Peak Shave Mode tests was to demonstrate the ability of the generator's controls to conduct the peak shaving operations and to observe the characteristics of the control algorithms for this mode of operation.
- Zero at the Breaker - The Zero Flow at the Breaker Demonstrations is a special case of the Peak Shaving Mode Demonstrations. In this case, the generators are operated in Peak Shave mode with a set point of zero kW. This mode is required when the Microgrid is transitioning from grid connected to Island Mode. To seamlessly transition to an island, the load at the breaker needs to be near to zero as the generators become the voltage and frequency source for the circuit. The Zero Flow at the Breaker Demonstrations also validate the ability for the two generators to operate in parallel while load following.
- VAr Control - The primary objective of the VAr Mode demonstration was to demonstrate the ability to have the generator provide VAr support to the circuit by adjusting the power factor settings.

Table 3 summarizes the standalone generator demonstrations that were conducted for this task. The Table presents the mode, which combination of generators are involved, the date and time of the operations, and the control interface used to conduct the operations.

Table 3: Standalone Generator Demonstration Plan

Mode of Operation	Microgrid Resource		Demonstration Description	Control Settings	Demonstration Date	Start Time	End Time	Control Interface	
	Gen1	Gen2						Local	Remote
Constant Output	X		DG Constant Mode Demo A	1000/1250/1500 kW	06/12/12	9:05	10:20	X	
		X	DG Constant Mode Demo A	1000/1250/1500 kW	06/12/12	10:15	11:30	X	
	X		DG Constant Mode Demo B	750/1000/1250/1500 kW	02/25/13	9:05	10:00		X
		X	DG Constant Mode Demo B	750/1000/1250/1500 kW	03/04/13	10:20	11:15		X
	X		DG Constant Mode Demo C	1800 kW	03/12/13	10:25	11:55		X
		X	DG Constant Mode Demo C	1800 kW	03/12/13	9:50	10:45		X
	X		DG Constant Mode Demo C	1800 kW	03/14/12	9:30	13:00	X	
	X		DG Constant Mode Demo C	1800 kW	03/15/12	8:15	12:00	X	
		X	DG Constant Mode Demo C	1800 kW	03/14/12	13:10	17:50	X	
		X	DG Constant Mode Demo C	1800 kW	03/28/12	9:20	10:15		X
	X	X	DG Constant Mode Demo D	500/750/500 kW	01/08/13	11:20	12:40		X
		X	DG Constant Mode Demo D	1000 kW	01/08/13	9:30	10:15		X
Peak Shave	X		DG LF Peak Shave Iteration Demo A	300 kW	06/14/12	9:00	10:40	X	
		X	DG LF Peak Shave Iteration Demo A	300 kW	06/14/12	10:37	12:17	X	
	X		DG LF Peak Shave Iteration Demo B	500 kW	11/15/12	9:40	11:30		X
	X		DG LF Peak Shave Iteration Demo B	650 kW	11/15/12	13:20	14:20		X
		X	DG LF Peak Shave Iteration Demo B	500 kW	11/15/12	14:20	15:20		X
	X		DG LF Peak Shave Iteration Demo C	1000 kW	03/11/13	10:05	11:30		X
	X		DG LF Peak Shave Iteration Demo C	Peak Shave of 15%	02/19/13	21:55	0:45		X
Zero at Breaker	X	X	DG LF Virtual Island with Zero Flow at Breaker Demo A	0 kW (Import)	06/18/12	9:26	10:51		X
	X	X	DG LF Virtual Island with Zero Flow at Breaker Demo A	0 kW (Import)	11/16/12	10:20	12:20		X
VAr Control	X		DG VAr Control Demo Setpoint-A	50/100 kVAr	01/08/13	11:20	12:45		X

Task 3.3 – Integration of Feeder Automation System Technology

Integration of Feeder Automation System Technology (FAST) for the Microgrid project was accomplished by the implementation of Fault Location, Isolation and Service Restoration (FLISR) functionality as part of the installed Outage Management System and Distribution Management System. The implementation and demonstration of the OMS/DMS FLISR system included leveraging the existing OMS/DMS integration with the distribution network SCADA system. The Microgrid Circuit was one of the initial circuits used to test and validate the operation of the system.

There is a significant investment in infrastructure, tools, and training that support a Distribution System Operator's rapid response to unplanned events. The recent implementation of a new Outage Management and Distribution Management System by the Utility are the foundation for improved systems environment.

Among the DMS functions are the capabilities of using SCADA telemetry and status values to recognize a fault location ("FL") in the distribution network, apply power flow capabilities to determine suggested switching alternatives and recommend a plan to isolate ("I") the fault and execute the steps necessary for service restoration ("SR"); FLISR.

A metric used to measure outages is Momentary Average Interruption Frequency Index (MAIFI); momentary outages are defined as customers affected less than or equal to five minutes. A circuit with SCADA devices that a DSO may use to isolate and restore service to the non-faulted area resulting in a momentary interruption of service for these customers is where FLISR plays a role. DSO’s look at the available SCADA data and maps to determine the faulted area in order to isolate and restore the non-faulted area. Their actions at times may take longer than five minutes as they are processing the available data. FLISR tool is looking at the same SCADA data and map for that outage providing a switch plan that can be auto executed reducing an outage for the non-faulted area to a momentary.

It can be a complex task to determine the optimal switch plan balancing all the objectives. The operator must determine what configurations are available, analyze the customer impact of each configuration, consider the circuit capacity available to carry additional loads, and balance the power requirements to device limitations to deliver power for partial restoration. In these situations, there are multiple variables, engineering and human, that can challenge the best operators.

The introduction of Microgrid resources further complicates an already complex activity. Microgrid resources introduce new devices having operational profiles and constraints. Among these added considerations are dynamic factors such as fuel levels in generators and state of charge of energy storage systems as well as environmental considerations such as optimal operating conditions and capacity.

The FLISR system provides a valuable tool to support DSOs in responding to and managing these unplanned outages with a range of alternatives for partial and full restoration. A properly implemented FLISR solution within a Microgrid has the potential to increase the reliability of service of customers within the Microgrid. The potential improvement in reliability will likely be associated with an overall reduction in outage duration but not the number of outages experienced. However, with FLISR, some outages that would typically be classified as “sustained” outages could be reclassified as “momentary” outages for the customers who can be restored within five minutes.

The functionality of the FLISR system resides in the Utility’s integrated OMS/DMS. The FLISR system responds to protection trips of SCADA monitored and controlled switches (i.e., circuit breakers (CB) and downstream reclosers). FLISR automatically identifies the faulted section using the telemetered Protection Trip and Fault Indication flags. When FLISR is operating in Auto Mode, it automatically schedules and carries out the isolation and restoration actions to restore the non-faulted areas that are de-energized by isolating the fault. In Manual Mode, FLISR presents the isolation and restoration plans as suggested switching plans that Distribution Operators may execute.

The Microgrid Circuit presented in Figure 12 is the initial demonstration case for the FLISR system for the entire utility distribution network. This diagram provides an overview of the FLISR design for the Microgrid Circuit.

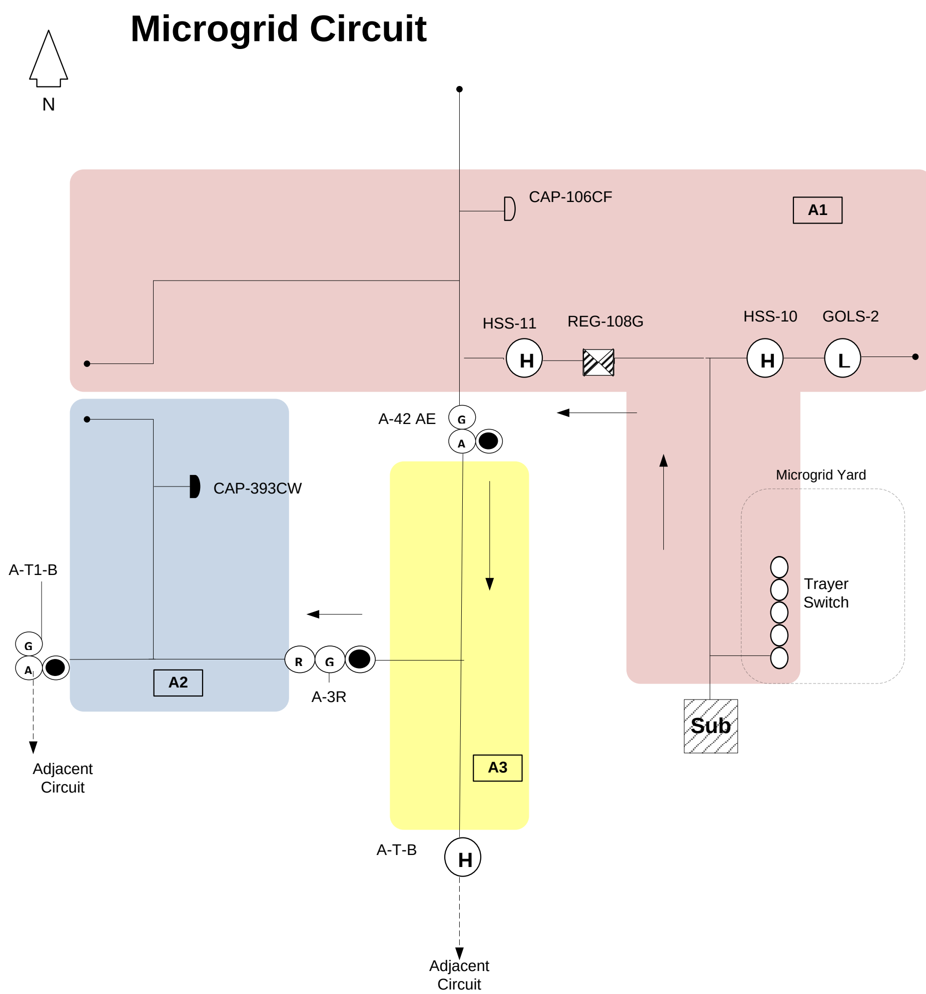


Figure 12: Microgrid Circuit FLISR Implementation

The Microgrid Circuit is divided into three sections: A1, A2 and A3 as identified in Figure 12. The circuit is powered through segment-A1's Microgrid Main Breaker at the substation. Alternatively, the circuit may be back-fed through tie-switches to adjacent circuits through segments A2 or A3. Segment A2 is connected to segment A3 via a SCADA automated switch and is available for FLISR operation. Segment A3's tie switch is not SCADA enabled (manual switch) and is not relevant to FLISR operations.

Once a fault area is determined, the FLISR system can isolate that area and restore customers in the non-faulted areas. If the fault is in section A2, then that section can be isolated by opening the device labeled "A-3R". Once isolated, customers in section A1 and A3 can have power restored. If the fault is in section A3 it is possible to isolate that section by opening switches "A-42 AE" and "A-3R". At that point, the customers in section A1 can be restored from the circuit substation. Customers in A3 can be restored by providing power from the circuit adjacent to A2. Similarly, if the fault is identified in A1 then that section can be isolated from A2 and A3 by opening "A-42 AE". Once isolated, sections A2 and A3 can be powered from the circuit adjacent to A2.

FLISR has additional factors to consider in the case of restoring power from the adjacent circuit. Because the restoration process will add load to the adjacent circuit, FLISR must use information and algorithms available from the DMS system to estimate the load of the restored section, determine if circuit capacity is available and if the planned switching scenario would cause any power flow violations such as conductor overload or voltages out of tolerance. This evaluation must be based on the immediate load on the adjacent circuit and the load to be added from sections A2 and A3. Additionally, the forecasted load could result in violation as the load changes over time. FLISR must consider all these factors before proceeding with a recommended switch plan.

There are three possible outcomes when restoring power from the adjacent circuit:

- The first is that the circuit cannot support any additional load and FLISR solution is presented with overload. In this case FLISR will not execute an automated solution.
- The second possible condition is that only the load on section A2, the immediately adjacent section, can be supported. In this case, section A3 would be isolated from the restoration and only customers in A2 would be restored.
- The final and best outcome is that the adjacent circuit can support the full load from customers in sections A2 and A3. In this case, all the customers in these segments would have power restored by the FLISR solution.

Task 3.4 – Stage 2 Distributed Systems Integration Testing

Since the Microgrid serves actual SDG&E customers, testing of FLISR had to be conducted in a simulation environment. The simulation includes specific scenarios for each of the different sections of the circuit. The objective was to demonstrate the ability of FLISR to identify correct switch plans that achieve the desired results without violating power flow rules. When the fault is initially detected by the OMS/DMS system the device shows in “Pending State” as shown in Figure 6.

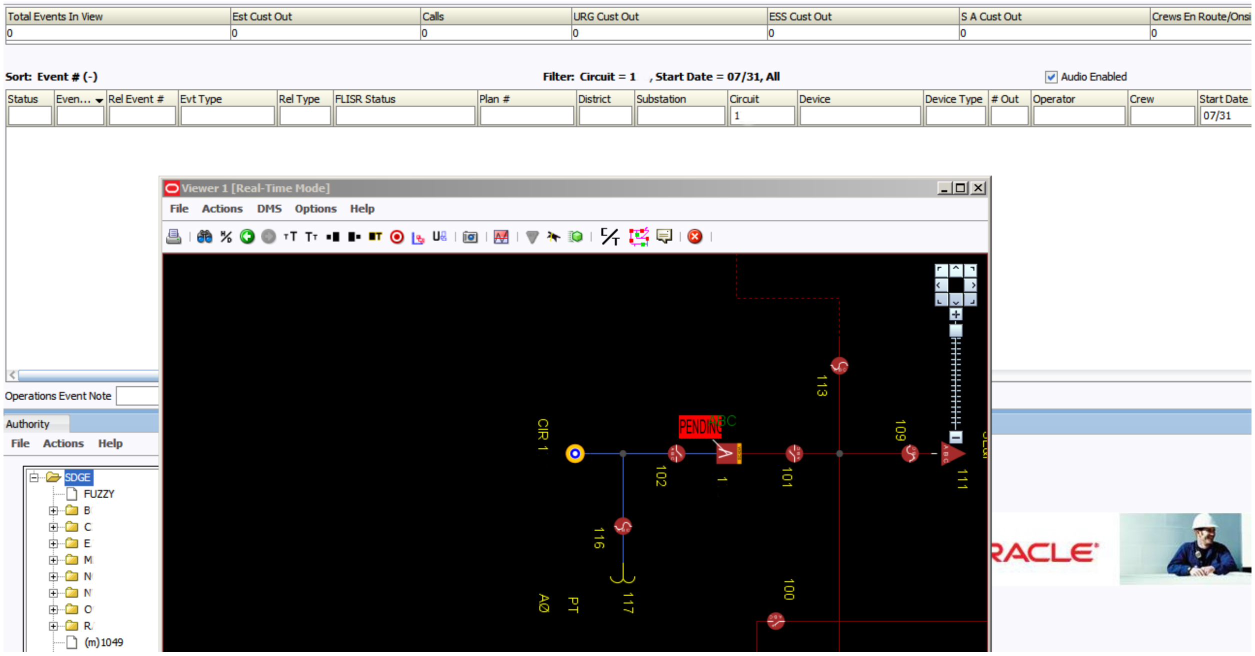


Figure 6: New Outage in Pending State

Once the OMS/DMS system confirms the outage through the SCADA interface, the status of the device displayed in the viewer changes from “Pending” to “RDO” or “Real Device Outage” as shown in the Viewer window in the foreground of Figure 7. At this point, the SCADA switch at the Microgrid Grid Circuit Breaker is open in response to a fault in the Microgrid Circuit.

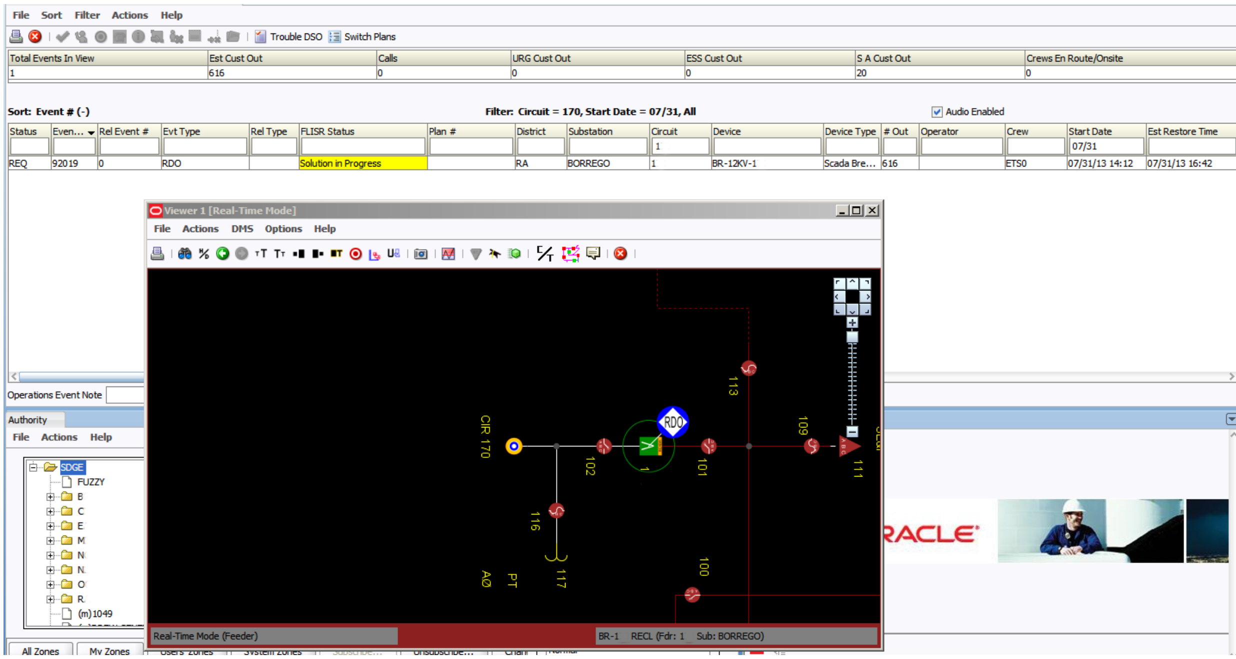


Figure 7: Real Device Outage Detected

In response to the recognition of a real device outage, the FLISR system begins the process of identifying a way to switch around the fault and restore power to customers outside of the faulted segment. FLISR actively works to identify the solution as indicated by the “Solution in Progress” for the newly created outage event in Figure 7.

For the demonstrations, it took 10 seconds for the OMS system to identify the RDO and for the DMS FLISR system to begin working on a solution.

Incidental to the DMS FLISR processing, the OMS system sends an automated request for assignment of a troubleshooting crew. This is indicated by the “Req” in the “Status” column in the work agenda. Additionally, the DMS executes a Fault Location Analysis (FLA) to identify specific locations within the faulted segment where the actual fault could be. By the time the crew calls in to distribution operations for instructions, the operator will have the information to direct the crew to a specific location.

In the event that FLISR is not able to develop a solution, the system will display “Solution Failed” on the work agenda. This exceptional condition is shown in Figure 8. This condition was created by placing the circuit SCADA devices in errant states. This was demonstrated to confirm that FLISR could recognize a failed solution.

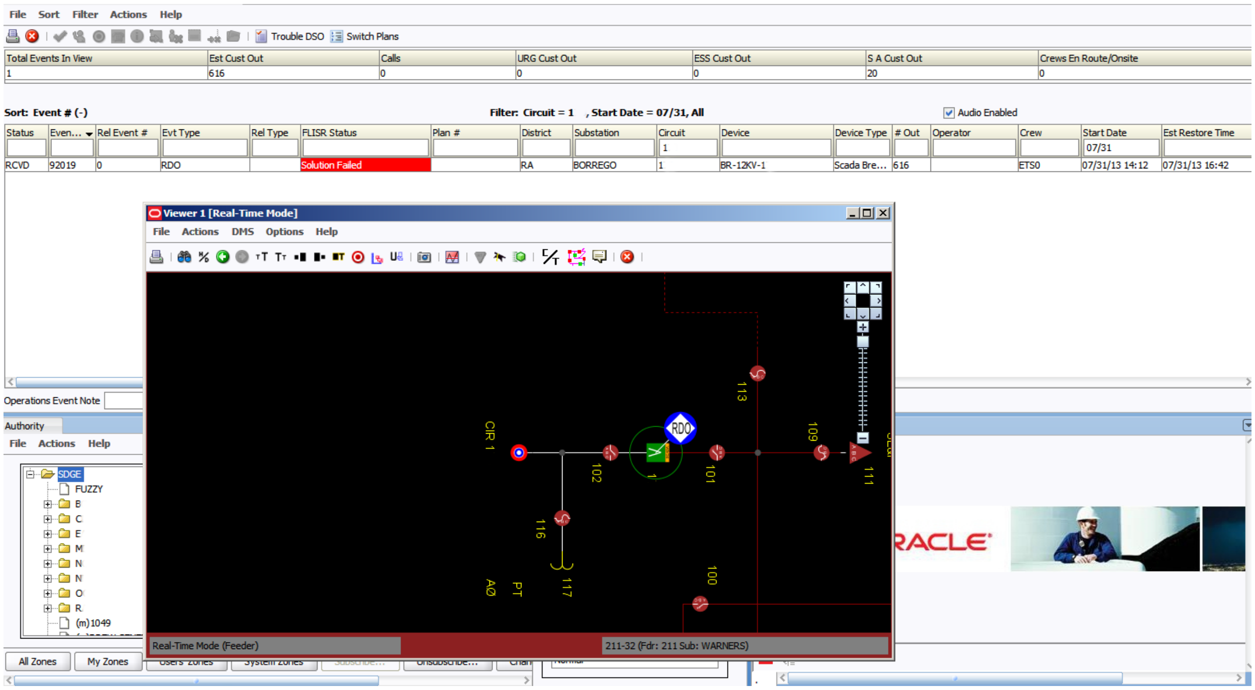


Figure 8: FLISR Solution Failed Exception

Task 3.5 – Integration of Advanced Energy Storage (AES)

This task addressed the integration of an Advanced Energy Storage (AES) system into the Microgrid. Since the AES system was deployed in the Microgrid substation, it is also referred to as the Substation Energy Storage (SES). The SES is comprised of a 500 kW /1,500 kWh lithium ion battery system. The SES was procured through a competitive solicitation based on a set of specifications included in a RFP. Approximately 12 qualified vendors were invited to submit a bid. Ten vendors submitted proposals which the project team evaluated based on the required specifications and the evaluation criteria.

Figure 9: Advanced Energy Storage

The SES is capable of serving multiple purposes, each represented by a control mode. These modes are user selectable from a remote operator interface provided by the SES vendor and function as directed by the AES internal controller using external inputs as required to define particular grid control conditions, such as grid element currents and voltages. The SES manages all functionality within equipment ratings capabilities and self-protection requirements. The SES operates in the following modes:

- Constant Power Charge and Discharge Mode
- Peak Load Management Mode
- PV Intermittency Smoothing Mode
- Self-Maintenance Mode
- Standby Mode
- Shutdown Mode

Unique specifications for the SES are as follows:

- The SES controls are configured to require a target State of Charge (SOC) prior to initiating operations in the programmed mode of operation
- The PCS is configured to interface and accept commands from a remote third party control system using a Modbus protocol
- The SES needed to have air conditioning units for each container to address the high outdoor temperatures of the desert climate
- The SES containers had to be installed three feet off the ground due flood plain issues
- The SES inverters are required to be capable of four quadrant operation

Task 3.6 – Stage 3 Distributed Systems Integration Testing

This task addresses the demonstration of the SES unit on the Microgrid Circuit. The objective of these demonstrations was to quantify the contributions of the SES operating in stand-alone operations on the Microgrid Circuit. The demonstrations are anticipated to show incremental improvement in circuit reliability, load reduction at the substation breaker, and improved VAr management. The data collected from the demonstrations is anticipated to validate the operational characteristics of the SES units including peak shaving ability, system efficiency, usable storage capacity, and operational reliability.

Following are the standalone SES demonstrations that were conducted:

- Constant Output – This demonstration’s objective is to charge or discharge the SES at a specified rate(s) of charge or discharge. The constant output mode operation represents the most basic operation of the SES and is thus used to allow the operators to become acquainted with the steps required to operate the equipment as well as learn how the SES responds to the given commands.

- Peak Shave – In this mode of operation, the SES supports an overall project goal to meet a 15% or greater peak load reduction. SES is not designed to meet this goal by itself but to contribute to meeting it in conjunction with other Microgrid Resources. In the Peak Shave Mode, the SES monitors and follows the load at the Microgrid Circuit Breaker and supplies an appropriate amount of electricity to meet a load that exceeds the input set point.
- VAr Control - The primary objective of the VAr Mode demonstration was to evaluate the ability of the SES to provide VAr support to the Microgrid Circuit. In this mode of operation the SES operates in constant output (kW), while varying it's VAr output to affect the reactive power at the Microgrid Circuit Breaker.
- Arbitrage – The objective of the Arbitrage Mode demonstrations was to test the ability to dispatch the SES charge and discharge operations in response to the CAISO nodal cost of electricity. For these demonstrations the SES units were charged during lower CAISO wholesale prices and discharged during higher CAISO wholesale prices
- Four Quadrant Operation - The objective of this demonstration was to observe the performance of the SES unit in the four quadrants of the power circle by operating the SES at multiple real power (kW) and reactive power (kVAr) settings. During this set of operations, the SES unit was set to various real power and reactive power settings consistent with the manufacturer's kVA (apparent power) rating of the unit.
- Efficiency Demonstration - These demonstration's evaluated the efficiency and total storage capacity of the SES system. Efficiency is evaluated based on the AC-AC round trip operation that is based on energy discharged from the system versus the electricity that goes into the battery to during the charging process.

Table 4 presents a comprehensive summary of all the AES stand-alone demonstrations conducted. The data identifies the description of the demonstration, the set points of the SES unit, the date, the start time, end time, and control method (local controls or remotely controlled). Remotely controlled operations were conducted through the Microgrid Visualizer. The table also shows that demonstrations were conducted several times and the specific iteration is identified. A total of 55 SES standalone demonstrations were conducted between October 2012 and March 2013.

Table 4: Standalone SES Demonstrations

Demo Description	Iteration	Settings	Demo Date	Start Time	End Time	Local/Remote
SES Constant Charge	1 of 1	125 kW	2/1/2013	13:00	18:45	Remote
SES Constant Charge	1 of 3	150 kW	11/28/2012	1:05	8:30	Remote
SES Constant Charge	2 of 3	150 kW	11/22/2012	1:05	8:30	Remote
SES Constant Charge	3 of 3	150 kW	1/9/2013	13:15	20:40	Remote
SES Constant Charge	1 of 2	185 kW	11/20/2012	1:10	7:00	Remote
SES Constant Charge	2 of 2	185 kW	12/11/2012	11:35	17:30	Remote
SES Constant Charge	1 of 3	250 kW	10/30/2012	8:30	10:30	Remote
SES Constant Charge	2 of 3	250 kW	11/19/2012	12:50	17:25	Remote
SES Constant Charge	3 of 3	250 kW	12/18/2012	4:10	8:30	Remote
SES Constant Charge	1 of 4	375 kW	12/4/2012	19:35	22:30	Remote
SES Constant Charge	2 of 4	375 kW	11/20/2012	10:05	13:00	Remote
SES Constant Charge	3 of 4	375 kW	12/10/2012	11:50	14:45	Remote
SES Constant Charge	4 of 4	375 kW	12/3/2012	14:05	15:15	Remote
SES Constant Charge	1 of 6	500 kW	11/19/2012	9:35	10:25	Remote
SES Constant Charge	2 of 6	500 kW	12/4/2012	9:35	10:45	Remote
SES Constant Charge	3 of 6	500 kW	12/4/2012	13:40	15:35	Remote
SES Constant Charge	4 of 6	500 kW	10/7/2012	9:40	11:20	Remote
SES Constant Charge	5 of 6	500 kW	10/8/2012	9:35	11:25	Remote
SES Constant Charge	6 of 6	500 kW	11/28/2012	13:35	15:40	Remote
SES Constant Charge	1 of 1	225/350/500 kW	12/18/2012	14:00	16:30	Remote
SES Constant Discharge	1 of 1	100 kW	12/4/2012	11:05	13:30	Remote
SES Constant Discharge	1 of 4	250 kW	2/1/2013	9:45	12:30	Remote
SES Constant Discharge	2 of 4	250 kW	12/3/2012	8:35	13:00	Remote
SES Constant Discharge	3 of 4	250 kW	11/22/2012	8:35	13:00	Remote
SES Constant Discharge	4 of 4	250 kW	1/9/2013	8:30	12:55	Remote
SES Constant Discharge	1 of 1	325 kW	12/4/2012	17:40	19:20	Remote
SES Constant Discharge	1 of 1	350 kW	11/28/2012	8:35	12:00	Remote
SES Constant Discharge	1 of 3	375 kW	11/20/2012	7:05	10:00	Remote
SES Constant Discharge	2 of 3	375 kW	12/11/2012	17:35	20:15	Remote
SES Constant Discharge	3 of 3	375 kW	12/3/2012	15:20	16:15	Remote
SES Constant Discharge	1 of 2	475 kW	10/30/2012	11:45	14:00	Remote
SES Constant Discharge	2 of 2	475 kW	12/7/2012	11:45	12:45	Remote
SES Constant Discharge	1 of 7	500 kW	11/19/2012	10:40	12:40	Remote
SES Constant Discharge	2 of 7	500 kW	11/19/2012	17:30	19:30	Remote
SES Constant Discharge	3 of 7	500 kW	12/18/2012	9:05	11:05	Remote
SES Constant Discharge	4 of 7	500 kW	12/18/2012	17:15	19:00	Remote
SES Constant Discharge	5 of 7	500 kW	12/4/2012	22:40	1:35	Remote
SES Constant Discharge	6 of 7	500 kW	11/20/2012	13:05	15:15	Remote
SES Constant Discharge	7 of 7	500 kW	12/10/2012	9:50	11:45	Remote
SES Constant Discharge	1 of 1	150/350/475 kW	12/10/2012	16:05	19:00	Remote
SES Constant Discharge	1 of 2	475/300/150 kW	12/7/2012	14:05	14:45	Remote
SES Constant Discharge	2 of 2	475/300/150 kW	10/8/2012	11:30	13:05	Remote
SES LF Peak Shave	1 of 1	800 kW	12/4/2012	15:45	17:00	Remote
SES LF Peak Shave	1 of 2	1000 kW	11/30/2012	11:00	13:00	Remote
SES LF Peak Shave	2 of 2	1000 kW	12/21/2012	13:55	15:05	Remote
SES LF Peak Shave	1 of 1	1250 kW	12/20/2012	8:15	13:00	Remote
SES LF Peak Shave	1 of 1	1500 kW	12/17/2012	13:55	14:35	Remote
SES VAr Control	1 of 4	- 240 kVAr	12/17/2012	14:45	15:50	Remote Control w/Manual Operation
SES VAr Control	2 of 4	+ 100 kVAr	1/4/2013	11:25	13:15	Remote Control w/Manual Operation
SES VAr Control	3 of 4	+ 200 kVAr	3/6/2013	13:40	14:55	Remote Control w/Manual Operation
SES VAr Control	4 of 4	+ 460 kVAr	3/11/2013	11:35	13:20	Remote Control w/Manual Operation
SES Arbitrage	1 of 2	333 kW Charge	12/1/2012	1:00	4:00	Remote
SES Arbitrage	1 of 2	450 kW Discharge	12/1/2012	17:00	19:00	Remote
SES Arbitrage	2 of 2	250 kW Charge	12/6/2012	1:00	4:00	Remote
SES Arbitrage	2 of 2	375 kW Discharge	12/6/2012	17:00	19:00	Remote

Task 3.7 – Integration of Outage Management System/Distribution Management System for Microgrid Operations

The Microgrid Operator is the point of contact to oversee and manage the control and monitoring functions for the Microgrid. To support the operation, the Microgrid Operator needs to tools to support the scheduling and operations of the Microgrid Resources. The major activities of the Microgrid operator include:

- Develop a daily load forecast
- Collect the appropriate day ahead CAISO Wholesale Price and input into the Microgrid pricing model
- Schedule Microgrid Resources to optimize Microgrid operations
- Create DR Event Trigger within the PDLM System as needed
- Schedule DR Resources within the PDLM System

The tools and system integrations that are required to facilitate these activities are a consolidated control interface, a load forecast model, and a resource pricing model.

Consolidated Control Interface

During the Microgrid design stage, it was envisioned that an external vendor would be added to the Project Team to develop the Microgrid Controller. The team worked with a third party vendor to develop system functional requirements and an integration plan for a Microgrid Controller until it became clear that the planned approach was not able to be executed in the required time frame. The Project Team decided to use in-house tools to develop a system (Microgrid Visualizer) that could support the Microgrid operations required to execute the Project Demonstration Plans. This tool was used as the integration point that provides the interface between the Microgrid resources and various SDG&E systems of the DMS, SCADA and Microgrid Operational Database.

The Microgrid Visualizer is a custom developed solution deployed on an OSI PI Asset Framework. Figure 10 presents a high level architecture for the Visualizer identifying infrastructure required at the Microgrid Site, a utility data center and the Microgrid Operator's office. The system communicates with the Microgrid Resources via a pair of gateways; one located in the data center and the other located in the Microgrid Yard with all resources within the Utility's secure network.

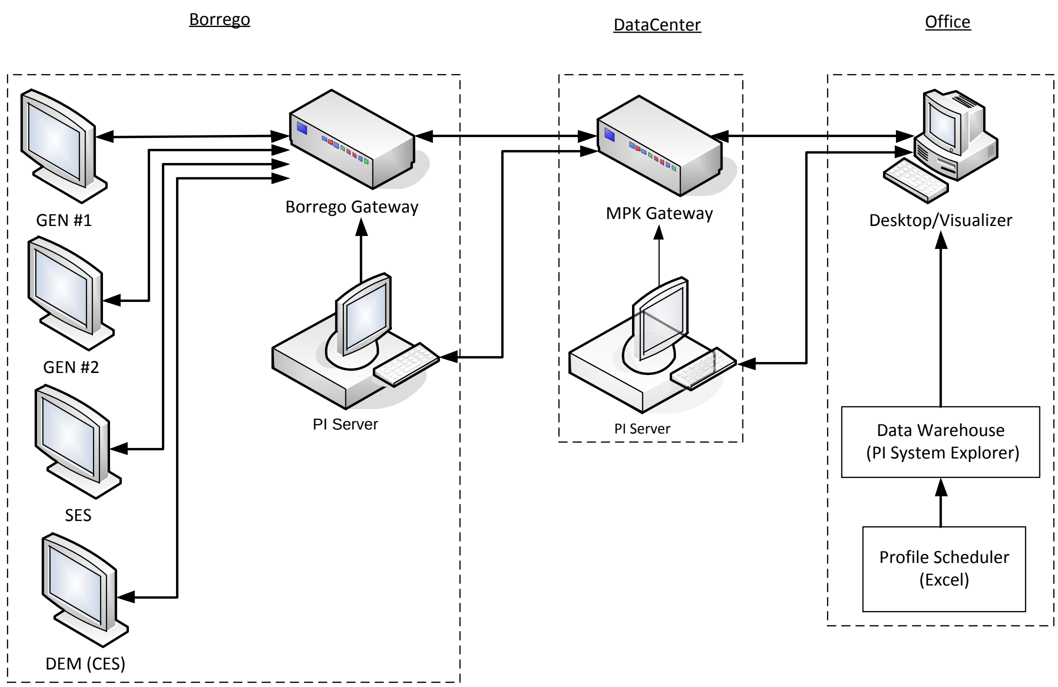


Figure 10: High Level Visualizer Architecture

The Microgrid Visualizer was created using PI Process Book to act as the user interface. The Microgrid Operator can access the Visualizer from the Control Van located within the Microgrid Yard or remotely from SDG&E's offices in San Diego. The Visualizer user interface is presented in Figure 11 with key monitoring and control components for the critical SCADA switches, circuit load, each of the DG units, SES system, and system alarms.

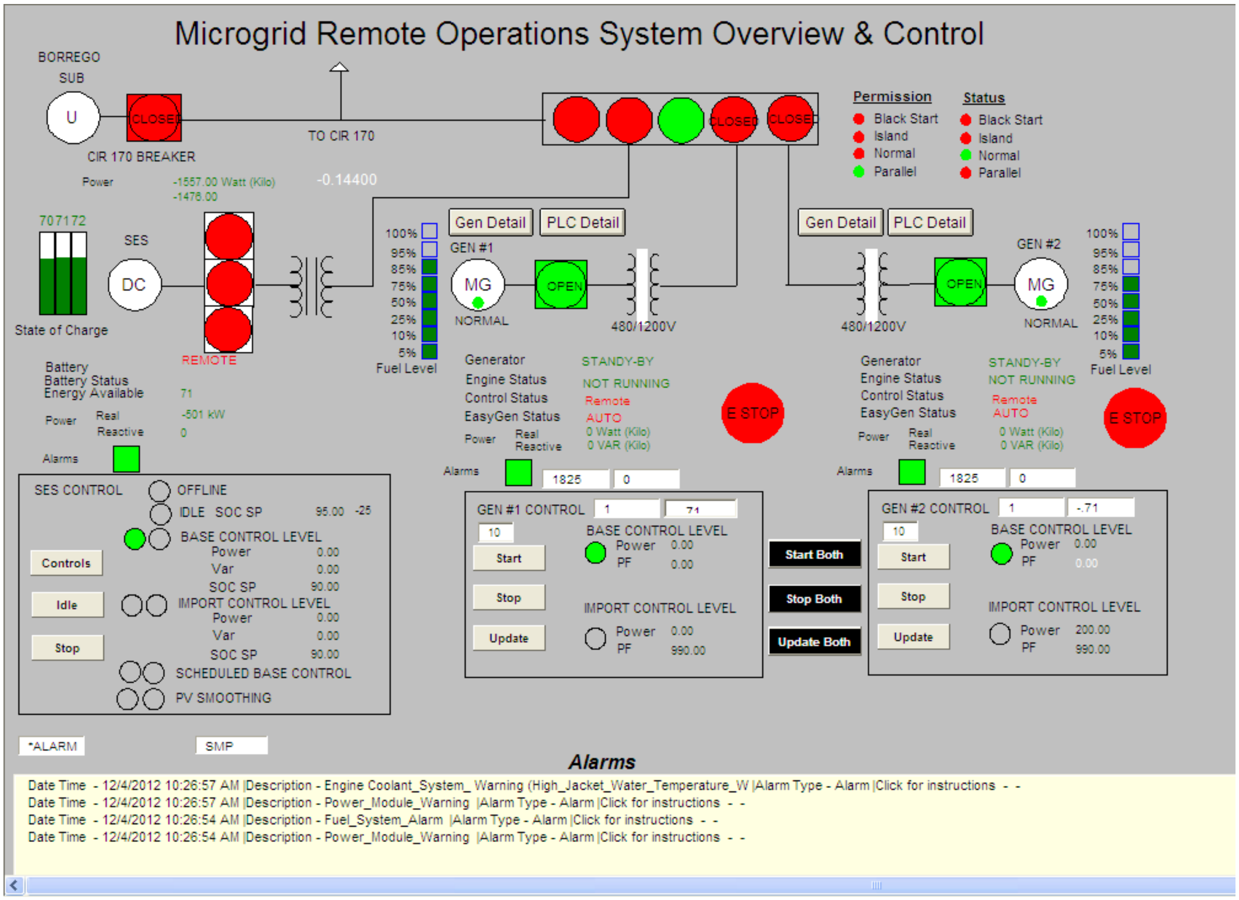


Figure 11: PI Process Book HMI Screen Design – Manual Mode Screen

The Visualizer provides the Microgrid Operator the option of operating the equipment in a manual mode or in a scheduled mode. The system is configured to continuously collect system data and store it in a PI database. Data can be easily extracted for analysis and reporting using a PI add-in for Excel.

Load Forecast Model

Several regression models were tested as the forecast model. Variations models showed that the air temperature is the most significant driver of the load during the daytime but not at night. The dew point and relative humidity did not add significantly to the accuracy of any of the tested models. The unique shape of the Microgrid Circuit load profile is attributed to high night-time loads from pumping operation by the water district and agricultural customers on the circuit. This phenomenon led to the inclusion of a "Pump Schedule Flag" in the model to account for the load shift resulting from time-of-use pricing incentives and highly elastic temporal energy demands. The best fit model was based on the following variables:

- Time of Day (Military format with no colon)
- Air Temperature (^{o}F)
- Pump Schedule Flag (1's and 0's, set to 1 from 11:00 PM to 5:00 AM)

- Average of three previous weekday's load at the same time day (MW)
- Average of three previous weekday's temperatures at the same time (^{o}F)

Forecast Load (MW) =

(Time x .000028) + (Pump Flag x .6719) + (Temp Forecast x .0339) + (3day Avg. Temp x -.0317) + (3day Avg. Load x .6029) + .460

Pricing Model

The Pricing Module was used to calculate the wholesale price of electricity ($/MWh) for electricity delivered to customers within the Microgrid. The wholesale price is dependent on the operation of Microgrid Resources along with the transmission grid. If the Microgrid resources are non-operational, the wholesale price is equal to the Locational Marginal Price (LMP) at the Borrego node. This LMP nodal price is obtained through an interface with CAISO's Nodal LMP system (referred to as OASIS). If the Microgrid resources are operational, the wholesale price is calculated by calculating an average weighted price of energy obtained from the grid at the LMP nodal price and the price of energy produced by the operating Microgrid Resources.

The wholesale price consists of the following components:

- DG# 1 Price – Price associated with the operation of Distributed Generator # 1
- DG# 2 Price – Price associated with the operation of Distributed Generator # 2
- Grid Price - The Grid Price is equal to the CAISO DAM LMP price for the Borrego Node
- SES Price – Price associated with the charge/discharge operation of the Substation Energy Storage unit

CAISO wholesale prices were downloaded from the CAISO OASIS website on a daily basis. The data was available in a comma separated values file and was transferred to the Microgrid Visualizer. An internal script running on the Microgrid Visualizer picked up the CAISO price and transferred the values to the Pricing Module once every 24-hours.

The base formula to calculate the Total Weighted Average Price ($Microgrid\ Price_{\$/MWh}$) is:

$$\frac{\left(MW_{DG1} * \frac{\$}{MWH_{DG1}}\right) + \left(MW_{DG2} * \frac{\$}{MWH_{DG2}}\right) + \left(MW_{SES} * \frac{\$}{MWH_{SES}}\right) + \left(MW_{GRID} * \frac{\$}{MWH_{GRID}}\right)}{MW_{DG1} + MW_{DG2} + MW_{SES} + MW_{GRID}}$$

An exception to this calculation occurs when the SES is in the charging mode. The Total Weighted Average Price ($Microgrid\ Price_{\$/MWh}$) during the charging interval is calculated by excluding the SES Aggregate Price component. The value of electricity in the SES unit is accounted for by using the LMP price at the time of the charging and the quantity of electricity added to the SES while charging. Prior to discharging the SES unit, the average cost of electricity for all the energy stored in the unit is calculated. This is used as the basis of the price of energy from the SES unit during the entire discharge cycle

Task 3.8 – Stage 4 Distributed Systems Integration Testing

The Microgrid Visualizer developed as part of this project was utilized as a core tool for remote operation of the Microgrid Resources during a majority of the demonstrations. The Visualizer was an important integration point to various utility systems like the OMS/DMS, SCADA system and the PDLM system. This tool was effectively used by Microgrid Operators to monitor and schedule the resources for operation in various modes to support Microgrid operations. The Visualizer required several external inputs to be loaded into the system manually. The Visualizer met the needs of the project to support planned demonstrations but is not sufficient to act as a standalone Microgrid Controller.

Figure 12 presents the Visualizer user interface when a scheduled operation is being executed. This interface provides the Microgrid Operator with the status and operating parameters of each of the Microgrid Resources as well as the scheduled operation. This provides feedback to the Operator whether or not the Microgrid is operating as anticipated.

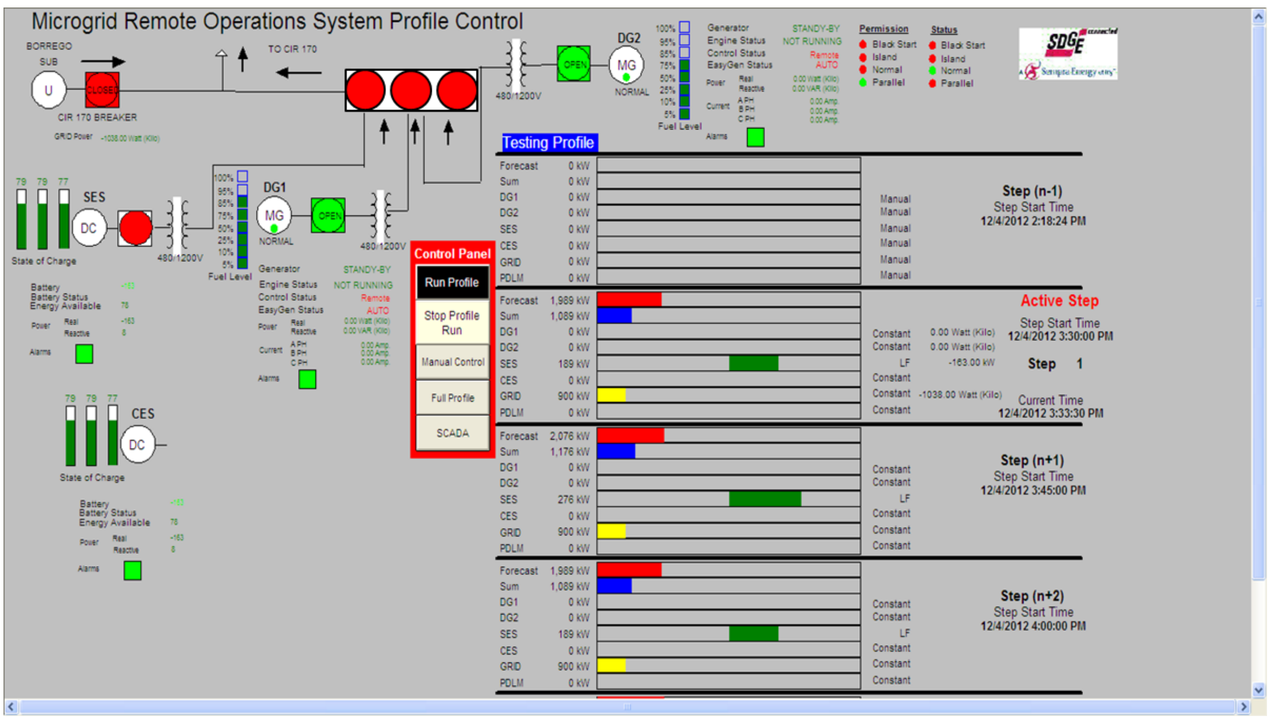


Figure 12: Microgrid Visualizer User Interface

The Load Forecast integrates with the Microgrid Visualizer to provide detail insight into the expected load over a 24-hour period and provides the ability to schedule resources on day-ahead schedule. The load forecast model was not as accurate or precise as hoped but was an effective tool to provide an estimate of timing and magnitude of peaks and well as validating the ability for Microgrid Resources to meet the anticipated Microgrid Circuit load during planned demonstration operations.

The Pricing Module was used effectively to translate the cost of operating Microgrid Resources as a wholesale price that could be passed on to the PDLM system to trigger pricing events. The Pricing Model was also used to try to operate a combination of Microgrid Resources in a cost-effective manner. This included influencing the timing and rates to charge and discharge the SES unit as well as selecting operating set points for the DG units.

Task 3.9 – Integration of Price-Driven Load Management

This task addresses the development and integration of a Price-Driven Load Management (PDLM) system for managing customer load on the Microgrid. The PDLM system dispatches the customer-side of the meter resources. The PDLM system interfaces with SDG&E's existing AMI system, project supplied Home Area Network (HAN) systems, and the Residential Energy Storage systems through the PDLM controller. Customer-side technologies that integrate into the PDLM system are:

- Programmable Communicating Thermostat (PCT)
- Load Control Switch (LCS)
- Plug Load Controller (PLC)
- In-Home Display (IHD)
- Residential Energy Storage
- Customer Web Portal

The PDLM controller is the system of record to forecast Demand Response (DR) capacity and schedule DR events to meet the load reduction objectives within the Microgrid. Figure 13 on the following page describes the PDLM architecture deployed in the Microgrid demonstration project.

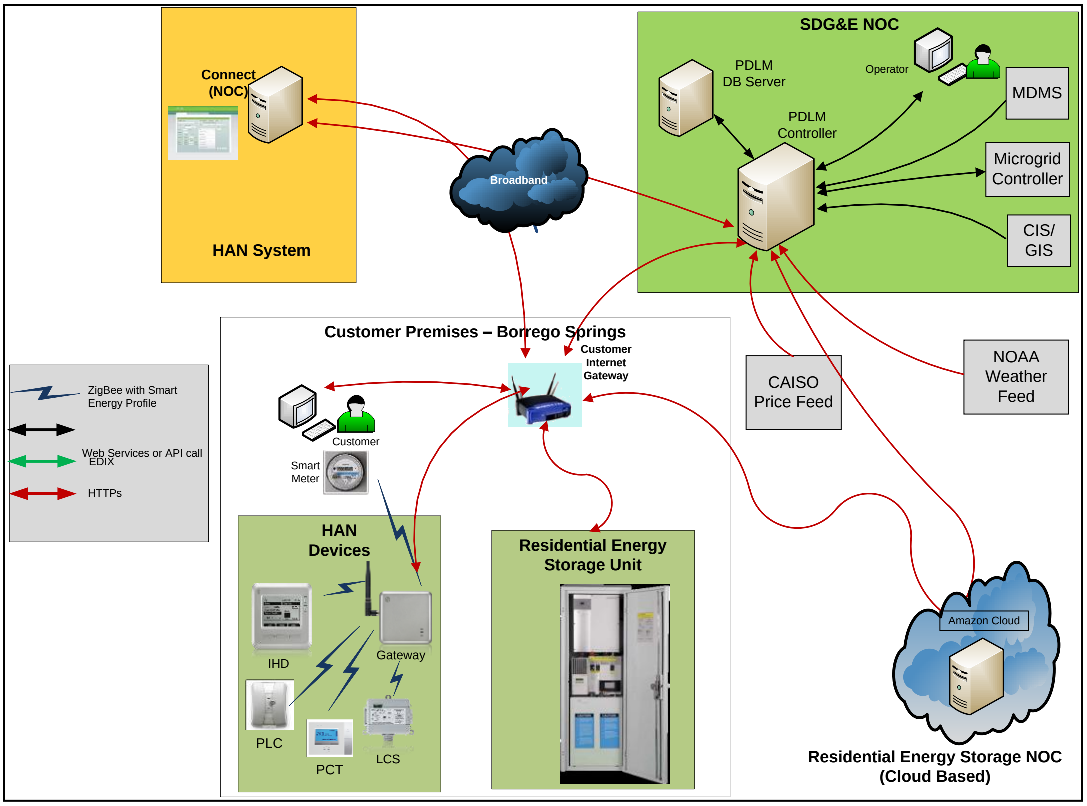


Figure 13: High Level PDLM Architecture

PDLM Controller - The PDLM controller functionality includes:

- Demand Response through Direct Load Control and Dynamic Pricing signals.
- Forecast Demand Response on a rolling 48-hour basis
- Monitor and execute Demand Response events
- Post-event measurement & verification (M&V)
- Analyze historical Demand Response data

The PDLM system enables operators to:

- Create and manage various types of Demand Response programs (i.e. Direct Load Control programs, Dynamic Pricing Program, etc.)
- Facilitate customer enrolment and notification of DR events, through its interface with the HAN System
- Initiate DR signals to be sent to the HAN devices through the HAN NOC
- Capture post event information for billing and inventive purposes
- Monitor and control the Residential Energy Storage system.

Figure 14 on the following page provides a snapshot of the utility portal that enables operators to perform the required Demand Response functions.

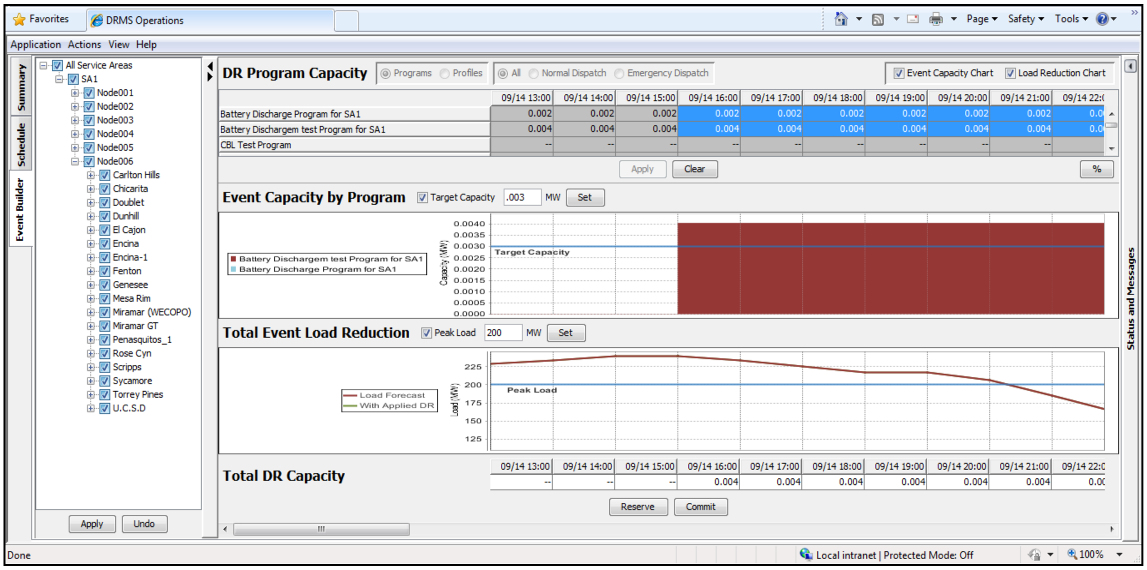


Figure 14: PDLM System Utility Portal

HAN System - The HAN Network Operations Center (NOC) manages HAN devices installed in customer premises. The devices are configured to control loads based on event-based activities demand response and price-based activities. The HAN system consists of a gateway that communicates with the in home devices (through wireless control signals) such as the in-home display, programmable communicating thermostats, load control switches, and plug load controllers. The end devices are configured to control loads based on event-based activities (i.e. demand response events) or price-based activities. Figure 15 shows a typical system configuration with the HAN devices installed in customer homes.

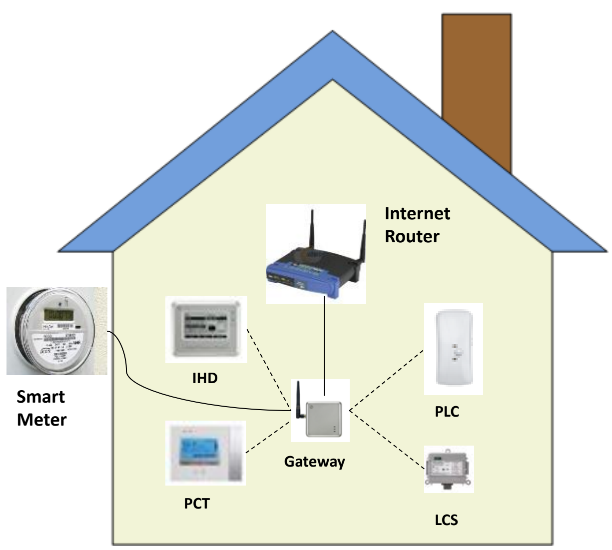


Figure 15: Typical Customer HAN Device Configuration

Task 3.10 – Stage 5 Distributed Systems Integration Testing

This task documents the PDLM demonstrations performed as part of the Microgrid demonstration. These operations were planned as Standalone PDLM demonstrations that were carried out to support the overall objectives in support of Microgrid operations. The PDLM demonstrations were conducted in two phases.

Phase 1 – Standard DR Demonstrations- The first phase of PDLM demonstration involved standard demand reduction programs. In standard DR events, the customer was enrolled in one or more demand reduction programs that would be planned a day in advance. During this phase, customers had the choice to participate or to opt out of any specific event. The following types of direct load control programs were developed (within the PDLM Controller) to meet the objectives of demonstrating Traditional Demand Response.

- PCT Program - The PDLM system sends a command to the program enrollee's PCT to modify the temperature set point. It supports multiple levels of temperature offset, as per customer preference.
- PLC Program - The PDLM system sends a command to the PLC which is connected to consumer devices like fans, lamps, televisions and other in-home devices. The PLC disconnects power to the consumer device during an event providing the anticipated reduction in load.

Table 5 presents information on the post event analysis provided by the PDLM controller for the Standard DR tests conducted between December 2012 and February 2013. The PDLM Controller's Analysis module provides the post-event analysis. It utilizes the configured DR Programs to execute DR events based on program constraints and restrictions. The DR Capacity Forecast is a learning algorithm that converges on the measured results each time a DR event is executed and accounts in the post event analysis. The results of the DR event are fed back into the DR Capacity Forecast.

Table 5: DR Events Demonstration Summary

Date	Start Time	End Time	Duration	Type of DR Program	Predicted Load Reduction (kW)	Actual Load Reduction (kW)	Scheduled Participants	Scheduled Devices	Devices Opted Out	Percent Device Participation	Percent Device Opt Out
12/13/12	14:00	15:00	1:00	PLC	418.50	(3.39)	50	91	8	91.2%	8.8%
12/14/12	14:00	15:00	1:00	PLC	38.50	(3.48)	50	91	8	91.2%	8.8%
12/18/12	14:00	15:00	1:00	PLC	38.40	(1.59)	50	91	8	91.2%	8.8%
12/20/12	15:00	16:00	1:00	PLC	42.60	(6.64)	35	45	7	84.4%	15.6%
1/8/13	14:00	15:00	1:00	4 ^{0}F Offset	12.70	7.67	47	58	0	100.0%	0.0%
1/8/13	14:00	15:00	1:00	PLC	37.90	9.82	50	91	7	92.3%	7.7%
1/8/13	15:00	16:00	1:00	4 ^{0}F Offset	19.10	12.70	47	58	0	100.0%	0.0%
1/8/13	15:00	16:00	1:00	PLC	42.20	13.24	50	91	7	92.3%	7.7%
1/17/13	14:00	15:00	1:00	PLC	4.10	1.02	50	91	6	93.4%	6.6%
1/17/13	15:00	16:00	1:00	PLC	19.10	3.68	50	91	6	93.4%	6.6%
1/22/13	14:00	15:00	1:00	PLC, 4 ^{0}F Offset	20.80	11.77	51	149	6	96.0%	4.0%
1/22/13	15:00	16:00	1:00	PLC, 4 ^{0}F Offset	35.90	7.83	51	149	6	96.0%	4.0%
1/24/13	15:00	16:00	1:00	PLC, 4 ^{0}F Offset	31.80	1.11	51	149	6	96.0%	4.0%
1/29/13	14:00	15:00	1:00	PLC	4.10	1.77	36	45	5	88.9%	11.1%
1/29/13	14:00	15:00	1:00	PLC	1.50	8.91	36	46	4	91.3%	8.7%
1/29/13	15:00	16:00	1:00	PLC	19.20	0.67	36	45	5	88.9%	11.1%
1/29/13	15:00	16:00	1:00	PLC	11.00	5.90	36	46	4	91.3%	8.7%
1/29/13	16:00	17:00	1:00	PLC	0.00	4.47	36	45	5	88.9%	11.1%
1/31/13	14:00	15:00	1:00	4 ^{0}F Offset	16.80	9.35	47	58	0	100.0%	0.0%
1/31/13	14:00	15:00	1:00	PLC	1.50	8.09	36	46	0	100.0%	0.0%
1/31/13	14:00	15:00	1:00	PLC	4.10	5.11	36	45	5	88.9%	11.1%
1/31/13	15:00	16:00	1:00	4 ^{0}F Offset	12.60	12.06	47	58	0	100.0%	0.0%
1/31/13	15:00	16:00	1:00	PLC	11.00	8.43	36	46	0	100.0%	0.0%
1/31/13	15:00	16:00	1:00	PLC	19.20	7.05	36	45	5	88.9%	11.1%
2/5/13	15:00	16:00	1:00	PLC	36.10	4.46	51	149	5	96.6%	3.4%
2/13/13	14:00	15:00	1:00	PLC	4.10	8.92	50	91	4	95.6%	4.4%
2/13/13	15:00	16:00	1:00	PLC	19.30	12.30	50	91	4	95.6%	4.4%
2/14/13	14:00	15:00	1:00	PLC	4.10	0.79	50	91	0	100.0%	0.0%
2/14/13	14:00	15:00	1:00	4 ^{0}F Offset	16.90	(2.08)	47	58	0	100.0%	0.0%
2/14/13	15:00	16:00	1:00	PLC	19.30	9.85	50	91	0	100.0%	0.0%
2/14/13	15:00	16:00	1:00	4 ^{0}F Offset	12.70	6.87	47	58	0	100.0%	0.0%
2/14/13	16:00	17:00	1:00	PLC	0.00	5.23	50	91	0	100.0%	0.0%
2/14/13	16:00	17:00	1:00	4 ^{0}F Offset	0.00	4.46	47	58	0	100.0%	0.0%
2/19/13	14:00	15:00	1:00	PLC	4.10	11.98	50	91	5	94.5%	5.5%
2/19/13	15:00	16:00	1:00	PLC	19.40	8.05	50	91	5	94.5%	5.5%
2/21/13	14:00	15:00	1:00	PLC	4.10	6.40	50	91	5	94.5%	5.5%
2/21/13	15:00	16:00	1:00	PLC	19.40	(4.47)	50	91	5	94.5%	5.5%
2/21/13	16:00	17:00	1:00	PLC	0.00	(3.82)	50	91	5	94.5%	5.5%
2/26/13	14:00	15:00	1:00	PLC	4.10	2.46	50	91	4	95.6%	4.4%
2/26/13	14:00	15:00	1:00	4 ^{0}F Offset	4.20	(6.31)	47	58	0	100.0%	0.0%
2/26/13	15:00	16:00	1:00	PLC	19.50	(0.81)	50	91	4	95.6%	4.4%
2/26/13	15:00	16:00	1:00	4 ^{0}F Offset	0.00	(3.24)	47	58	0	100.0%	0.0%

Data from Table 5 was analyzed to understand the effect of Demand Response on customer load reduction. Between December 2012 and February 2013, a total of 42 Demand Response events were implemented. Each DR event was scheduled for 1 hour, while some days had multiple DR events. Out of the 42 DR events, 32 DR events registered a net reduction in customer load, while 10 DR events registered a net increase in customer load. This analysis shows that 76% of the time a net reduction in customer load was observed, while 24% of the time a net increase in customer load was observed. During the 32 DR events in which a load reduction was observed, the average total load reduction was 7.0 kW. During the 10 DR events in which a load increase was observed, the average total load increase was 3.6 kW. The average total change in load across all 42 DR events was a total load reduction of 4.4 kW. A summary of the event analysis for the DR events conducted between December 2012 and February 2012 is presented in Table 6.

Table 6: DR Events Load Reduction Summary

Number of DR Event Days	16 Days
Number of DR event hours	42 Hours
DR events with Load Reduction	76%
DR events with Load Increase	24%
Average Load Reduction (when load reduced during DR events)	7.0 kW / event
Average Load Increase (when load increase during DR events)	3.6 kW / event
Average Load Reduction During all DR events	4.4 kW

During the initial DR events the predicted load reduction was observed to be higher than the actual available DR on the Microgrid Circuit. A correction factor was applied to the DR Forecast algorithm that provided more accuracy to the forecast. Since many of the events have a measured net increase in load, secondary analysis was conducted to identify specific instances of customers who reduced their load during the events. Data was collected and analyzed from the HAN NOC. This data is not typically available to the end user and was requested by the project team. The process of acquiring the data was not straight forward as the HAN vendor does not typically store this data. The Vendor had to develop a special case to capture and archive this data for the team to analyze. As a result of the problems for the vendor to obtain the data and unique nature of the request, the HAN data was not available for all of the events that were executed.

Since the post event data represents the load impact of the aggregated customer base, further analysis was performed to understand the effect of DR events on individual customer load reduction. Hourly customer interval data was obtained from the AMI system for customers that participated in the DR demonstrations. The data was analyzed to see the trend of customer load on the days of the event and an average of the customer load over 3-days or 7-days prior to the event. This analysis identified several instances of actual load reduction in customer homes during the DR demonstrations. In absence of the DR events, the customer load would have remained higher. Figure 16 presents AMI data for a sample customer who participated in the DR events and had significant load reduction of during the DR events. The chart below presents two load curves for comparison:

- Event Day Load Curve (red line), and
- Average Load for Days Prior to Event (black line)

As presented in Figure 16, a two hour DR event was executed between 14:00 and 16:00. The load of the customer was significantly higher than the average load at the beginning of the event and was reduced to a level lower than the average during the second hour of the event (to less than 1.0 kW). The data shows that the customer had an overall load reduction of 4.6 kW during the event.

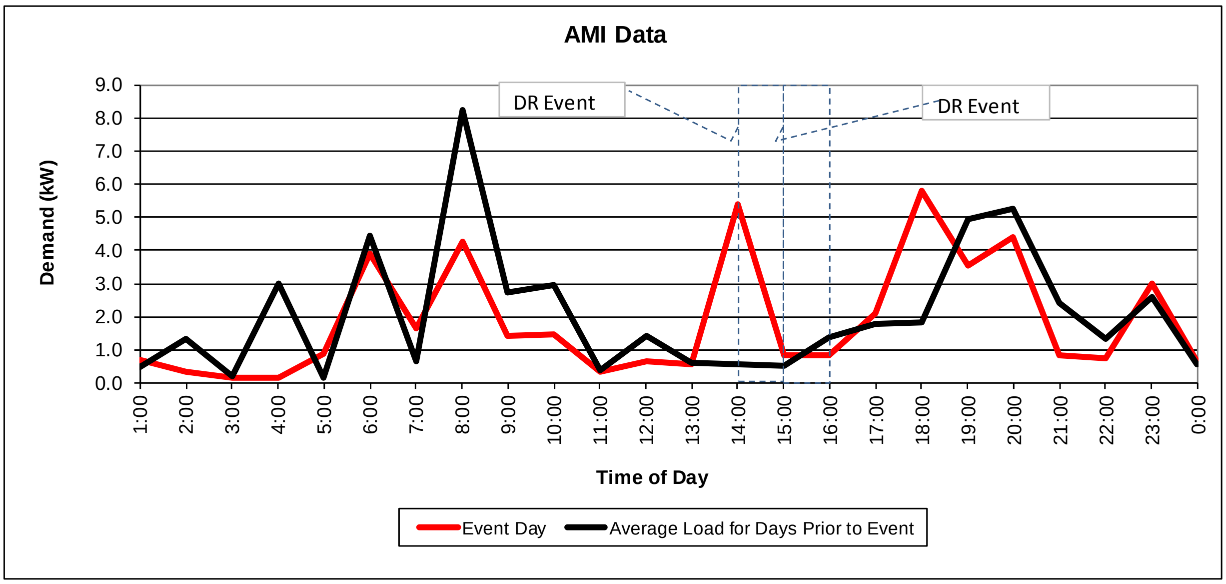


Figure 16: Example 1- Customer Load Reduction During DR Events

Phase 2 – Simulating Pricing Demonstrations - The second phase of the PDLM demonstration was based on triggering demand reduction based on pricing signals that were communicated to the HAN systems. In these programs, the customer does not have a simple opt out option but can alter the impact of the event by changing their pricing threshold through the customer portal. This allows a customer with two Programmable Communicating Thermostats (PCTs), for example, to have one accept the temperature offset at one price point while the other PCT participates at a higher price point. The PDLM system transmits simulated wholesale prices which are translated into retail pricing after taking into consideration the CAISO nodal pricing in Borrego Springs and the cost of operating Microgrid resources. The customers have the ability to configure individual in-home devices to respond to a retail price. Thus, the equipment operation varies as the price of electricity fluctuates. These dynamic retail prices are visible to the customer on the In-Home Display.

Table 7 presents the M&V results as reported by the PDLM system for the pricing events that were conducted.

Table 7: Pricing Events Demonstration Summary

Date	Start Time	End Time	Duration	Type of RTP Program	Predicted Load Reduction (kW)	Actual Load Reduction (kW)	Scheduled Participants	Scheduled Devices	Devices Opted Out
3/4/20	14:00	15:00	1:00	Level 4 (PCT 2°F Offset)	1.50	(0.952)	6	7	0
3/4/20	15:00	16:00	1:00	Level 5 (PCT 4°F Offset)	3.00	0.020	6	7	0
3/5/20	18:00	19:00	1:00	Level 4 (PCT 2°F Offset)	0.00	(7.828)	47	58	0
3/7/20	18:00	19:00	1:00	Level 4 (PCT 2°F Offset)	0.00	(9.792)	47	58	0
3/8/20	15:00	16:00	1:00	Level 5 (PCT 4°F Offset)	0.00	(3.192)	53	64	0
3/13/20	12:00	13:00	1:00	Level 4 (PCT 2°F Offset)	13.80	0.096	53	64	0
3/13/20	13:00	14:00	1:00	Level 5 (PCT 4°F Offset)	27.60	5.295	53	64	0
3/14/20	13:00	14:00	1:00	Level 4 (PCT 2°F Offset)	13.80	(3.980)	53	64	0
3/15/20	14:00	15:00	1:00	Level 4 (PCT 2°F Offset)	13.80	(13.877)	53	64	0
3/21/20	14:00	15:00	1:00	Level 4 (PCT 2°F Offset)	13.80	4.433	53	64	0
3/21/20	15:00	16:00	1:00	Level 5 (PCT 4°F Offset)	27.60	(4.270)	53	64	0
3/26/20	14:00	15:00	1:00	Level 4 (PCT 2°F Offset)	8.20	1.420	33	38	0
3/28/20	15:00	16:00	1:00	Level 5 (PCT 4°F Offset)	15.40	(1.920)	31	36	0
4/2/20	19:00	20:00	1:00	Level 4 (PCT 2°F Offset)	7.70	(4.374)	31	36	0
4/2/20	20:00	21:00	1:00	Level 5 (PCT 4°F Offset)	7.70	(8.030)	31	36	0
4/3/20	14:00	15:00	1:00	Level 5 (PCT 4°F Offset)	15.50	(5.874)	31	36	0
4/11/20	15:00	16:00	1:00	Level 5 (PCT 4°F Offset)	13.30	(7.650)	28	31	0
4/11/20	16:00	17:00	1:00	Level 4 (PCT 2°F Offset)	6.60	(8.805)	28	31	0
4/12/20	15:00	16:00	1:00	Level 5 (PCT 4°F Offset)	13.30	(8.925)	28	31	0
4/12/20	16:00	17:00	1:00	Level 4 (PCT 2°F Offset)	6.60	(17.945)	28	31	0

Data from Table 7 was analyzed to understand the effect of Price Driven Demand Response on customer load reduction. Between March 2012 and April 2013, a total of 20 Pricing Events were implemented. Each Pricing event was scheduled for 1 hour, with some days having multiple pricing events. Out of the 20 Pricing Events, 5 events registered a net reduction in customer load, while 15 events registered a net increase in customer load. From these numbers it can be inferred that 25% of the time a net reduction in customer load was observed, while 75% of the time a net increase in customer load was observed. During the 5 Pricing Events in which a load reduction was observed, the average total load reduction was 2.25 kW. The average total change in load across all 20 Pricing Events was a total load increase of 4.8 kW. A summary of the event analysis for the Pricing Events conducted in March 2013 and April 2013 is presented in Table 8.

Table 8: Pricing Events Load Reduction Summary

Number of RTP event days	14 Days
Number of RTP event hours	20 Hours
RTP events with Load Reduction	25%
RTP events with Load Increase	75%
Average Load Reduction (when load reduced during RTP events)	2.25 kW / event
Average Load Increase (when load increase during RTP events)	7.16 kW / event
Average Load Increase During all RTP events	4.8 kW

Since many of the events have a measured net increase in load, secondary analysis was conducted to identify specific instances of customers who reduced their load during the events. Data was collected and analyzed from the HAN NOC. This data is not typically available to the end user and was requested by the project team. The process of acquiring the data was not straight forward as the HAN vendor does not typically store this data. The Vendor had to develop a special case to capture the data as requested by the project team. Due to the unique nature of the request, the HAN data was not available for all of the events that were executed. The analysis included understanding the effect of Pricing Events on actual customer load reduction. Hourly customer interval data (kW) was downloaded from the Meter Data Management System for customers that participated in the Pricing demonstrations. The data was analyzed to see the trend of customer load on the days of the event and an average of the customer load over 3-days or 7-days prior to the event.

This analysis helps present instances of actual load reduction in customer homes during the Pricing Event demonstrations. Figures 16-19 present the load profiles for certain customers who participated in the Pricing events, and had significant load reduction of during these events. The charts below present two load curves for comparison:

- Event Day Load Curve (red line)
- Average Load for Days Prior to Event (black line)

Figure 17 presents an example of a customer load during two consecutive Pricing Events [Level 4 (PCT 2 ºF Offset) and Level 5 (PCT 4 ºF Offset)] that were executed between 14:00 and 16:00. The data shows a reduction in load during the first hour and then a further decline during the second hour when the PCT set point was adjusted an additional 2°F. This customer demonstrated a load reduction of 2.4 kW during the event.

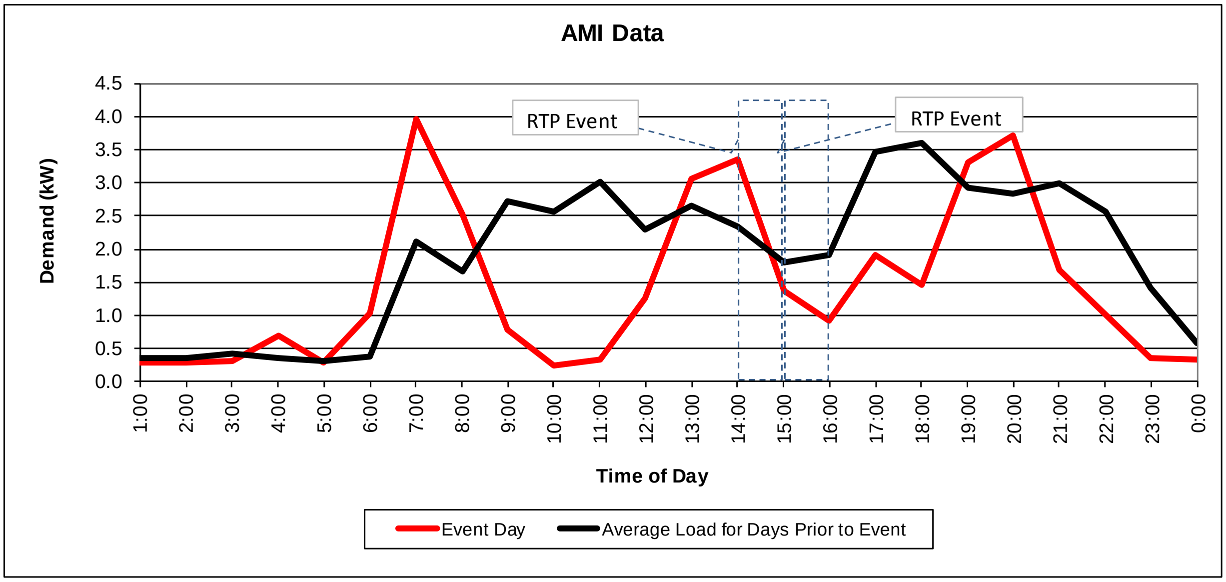


Figure 17: Example 1- Customer Load Reduction During Pricing Event

A major objective of the demonstration project was to discover how the PDLM resources could be managed in the Microgrid environment and if PDLM could be managed like the other DER resources. Ideally, PDLM could be managed in the Microgrid the way that generators or storage systems are managed.

The PDLM is limited and constrained by the capacity of PDLM to deliver load reduction depends on weather, time of day, and customer behavior. With PDLM, operations must address the needs of customers as well and devices and systems. Agreements with customers limit the frequency and duration of PDLM events. Customers have the option to opt-out of events. The dependability of PDLM resources can vary with customer fatigue and other uncontrollable customer behavior.

Finally, the methodology for forecasting demand reduction is largely based on trial and error with incremental refinement of estimates based on experience. This means that early forecasts are unlikely to be reliable. It takes considerable refinement over multiple events to develop reliable estimates. All the issues that impact the PDLM forecasts would be improved by removing the customers' freedom of choice. However, for these demonstrations, that was not an option.

Taken together, PDLM is very different from the other DER resources being managed by the Microgrid Controller. While it can be dispatched as part of the overall Microgrid Optimized plan, benefiting from PDLM requires a wider variety of operational considerations and is far less reliable and predictable than other resources.

Task 3.11 – Feeder Optimization Testing

Task 3.11 builds on Distributed Systems Testing undertaken in Tasks 3.2, 3.4 and 3.6 to integrate various Microgrid resources and operate them to achieve optimization operation of the Microgrid Circuit and the Microgrid Resources. The objective of this task is to operate the Microgrid utilizing the combination of resources in a manner that achieves a 15% or greater peak load reduction, increases reliability and operates in a cost-effective manner. This will be achieved through the use of the load forecast tool, CAISO pricing signals, the Microgrid Visualizer and the sequence of operation of the Microgrid Resources. The key optimization activities address the following operating scenarios:

- Distributed Energy Resource and Substation Energy Storage sequence of operation
- Peak Shave operation (Reducing night time peak load)
- VAr Operation with DG and SES
- Microgrid Island Operation

These demonstrations validated the objective of achieving 15% peak load reduction on the Microgrid Circuit by simultaneous operation of the Microgrid resources. The sequence of operations required to operate the Microgrid resources under these scenarios provides valuable operational information that can be used for future Microgrid operations. The Microgrid resources can be planned for combined operation based on the load forecast, and are able to react to changes in load on the circuit by operating at modified set points. The findings from the various demonstrations can be summarized below:

- The constant output demonstrations show that while the resources were able to operate in individual constant output modes, they were also able to operate simultaneously. The operation DG and SES was able to meet a higher percentage of the load on the circuit, thereby reducing the power imported from the grid. The demonstrations identified that the SES could operate in both charge and discharge modes and rates of energy transfer without adversely affecting the DG operation.
- The peak shave demonstrations show that the Microgrid resources (DG and SES) could be effectively used to reduce the peak load on the circuit. An important objective of the overall Microgrid project was demonstrated effectively, when the DG and SES were able to reduce the peak load on the Microgrid Circuit (which occurs at night time) by more than 15%.
- During peak shave mode the resources can be programmed to operate in multiple modes, i.e. load following or constant output, to reduce the peak load on the circuit. The demonstrations resulted in the identification specific sequences of operation required to maintain stability when both DG and SES are operating.
- The zero flow at the breaker demonstrations show that the Microgrid resources can be effectively used for planned island operation of the Microgrid Circuit. The Microgrid resources (DG and SES) were able to keep the grid power to near zero, and could transition seamlessly from parallel operation to carrying the entire load on the circuit.

- The VAr demonstrations showed that the combined resources of DG and SES are able to be controlled to desired levels with a combination of the two resources
- The Island Demonstrations demonstrated the capability of the Microgrid to island itself from the grid, carry the load on the circuit, maintain power quality that is acceptable within the utility operational range, and seamlessly transition from island operation back to grid parallel operation.
- Finally, these demonstrations show that the Microgrid can be optimized to operate under various desired scenarios.

4.3 Phase 3 – Data Collection and Analysis

Task 5.1 – Cost/Benefit Analysis for Large-Scale Deployment

The Microgrid team conducted a cost benefit analysis to determine:

- Applicable locations in the service territory where Microgrid solutions would generate maximum benefits
- What issues, if resolved, would generate the benefits
- What technologies grouped into an analyzed and identified solution would provide the most benefit for cost (capital and O&M)
- Which subset of locations should the solutions be applied to keep the investment reasonable and benefits maximized

Figure 18 summarizes how the model was constructed to link benefits to solutions to the territorial fit.

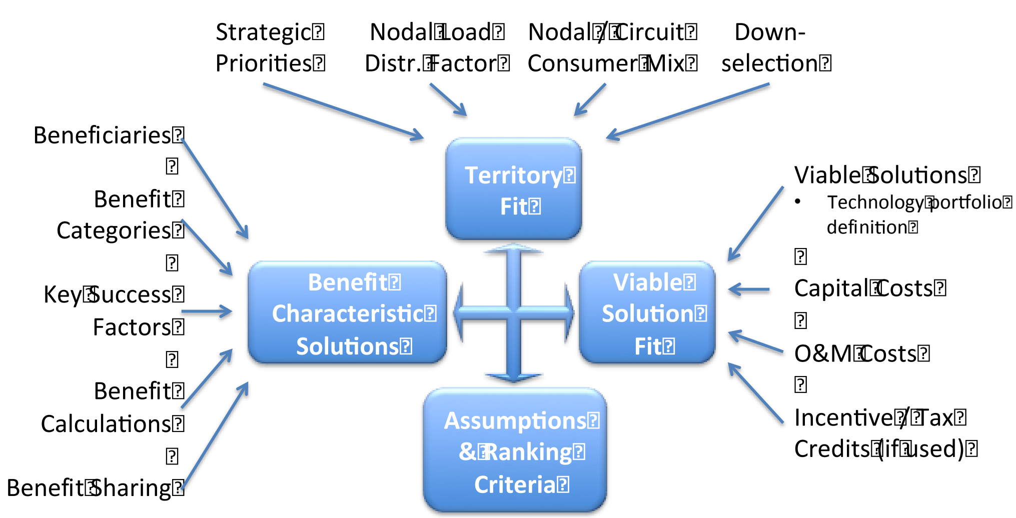


Figure 18: SDG&E CBA Model Overview

In the CBA, costs are based on findings from the Borrego Springs Microgrid Project made in the baseline phase of the project. In the CBA, benefits are treated as differences between the project baseline and benefits enabled via the technologies and solutions implemented and tested during the integration and testing of various technologies. Benefits are accrued to three beneficiaries:

- Consumer – benefits that directly accrue to consumers served by the identified solutions (costs) implemented for their benefit
- System – benefits that directly accrue to the utility's electric network served by the identified solutions (costs) implemented to benefit the electric network's reliability, economics, and/or sustainability
- Society – benefits that broadly accrue to many consumers and society served by the identified solutions (costs) implemented to benefit society with improved reliability, better economics and improved sustainability

The CBA used the following references as the main support for the methodology:

- SDG&E Smart Grid Deployment Plan (filed with the California Public Utility Commission June 2011)
- Electric Power Research Institute Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects (rev 1, 2012)
- San Diego Smart Grid Study (2006)
- West Virginia Smart Grid Implementation Plan (2009)

Task 5.2 – Implementation Plan for Large Scale Deployment

A deployment plan was developed for the optimized Microgrid solutions that were consistent with the CBA of Task 5.1 report. The approach used was to extrapolate a large-scale deployment of selected advanced distribution control (Microgrid) / DER strategies that meet the requirements of the CBA of Task 5.1.

The Task 5.1 report presents five identified solutions structured to enable maximum benefits at specific load nodes on the SDG&E distribution network. The identified solutions are:

A. Large Microgrid (10 MW)
B. Medium Microgrid (4 MW)
C. Small Microgrid (1 MW)
D. Distributed Energy Resource (DER) solution (0.3 MW)
E. Residential solution (0.004 MW)

The benefits are derived from addressing issues specific to commercial and industrial (C&I) consumer needs, communities challenged by high penetration of solar PV (HPV), weak points (WP) in the network, end of circuit (EOC) challenges, and other (O) special needs (e.g. sports venues, data centers, and hospitals). The benefits from addressing these challenges accrue to certain beneficiaries:

- Consumer (direct benefit to single consumers)
- System (direct improvement in operations, system efficiency, and capital efficiency)
- Societal (broadly applied benefits to many consumers)

The CBA resulted in 28 identified solutions in two phases. The 28 identified solutions include:

- 10 MW Microgrid: Quantity = 2
- 1 MW Microgrid: Quantity = 8
- DER Solutions (300kW): Quantity = 18

The proposed deployment plan covers eight years in two Phases:

- Phase 1: years 0 through 2; 10 identified solutions, all DER solutions
- Phase 2: years 3 through 7; 18 identified solutions; 2 large Microgrids, 8 small Microgrids, and 8 DER solutions

5 Project Outcomes

The Borrego Springs Microgrid demonstration involved operation of the Microgrid Resources under various scenarios. These demonstrations were planned to test the fundamental operation of the resources in standalone mode, as well as to operate the resources simultaneously to achieve specific project objectives. The key observations of all the demonstrations conducted are presented in individual task reports outlined in the Approach Section. This section presents key findings and observations that illustrate the ability of the Microgrid to meet specific objectives outlined in Section 3 (Objectives).

Objective 1: Demonstrate the ability to achieve 15% or greater reduction in feeder peak load

Results: The Borrego Springs Microgrid was designed to meet the operational objective of achieving 15% or greater reduction in feeder peak load. Through multiple demonstrations the Microgrid was able to meet this objective. This section highlights two scenarios where the Microgrid resources operated at settings that reduced the load on the circuit by 15%.

Figure 19 on the following page presents the demonstration of the 15% peak load reduction during the night-time peak of the circuit. The demonstration plan was to shave the night-time peak load by reducing the load at the Microgrid Circuit Breaker by the 15% requirement of 695 kW. The load forecast predicted that the load would increase significantly at 11:00 PM due to the operation of the water district's water pumps and the commercial customer irrigation pumps. The generators were started, warmed up, and synchronized to the circuit starting at 10:30 PM. As the load increased at around 10:55 PM, the generator peak shave set point limit was set to 1,600 kW. The demonstration ended at 1:00 AM due to the noise and environmental permit requirements.

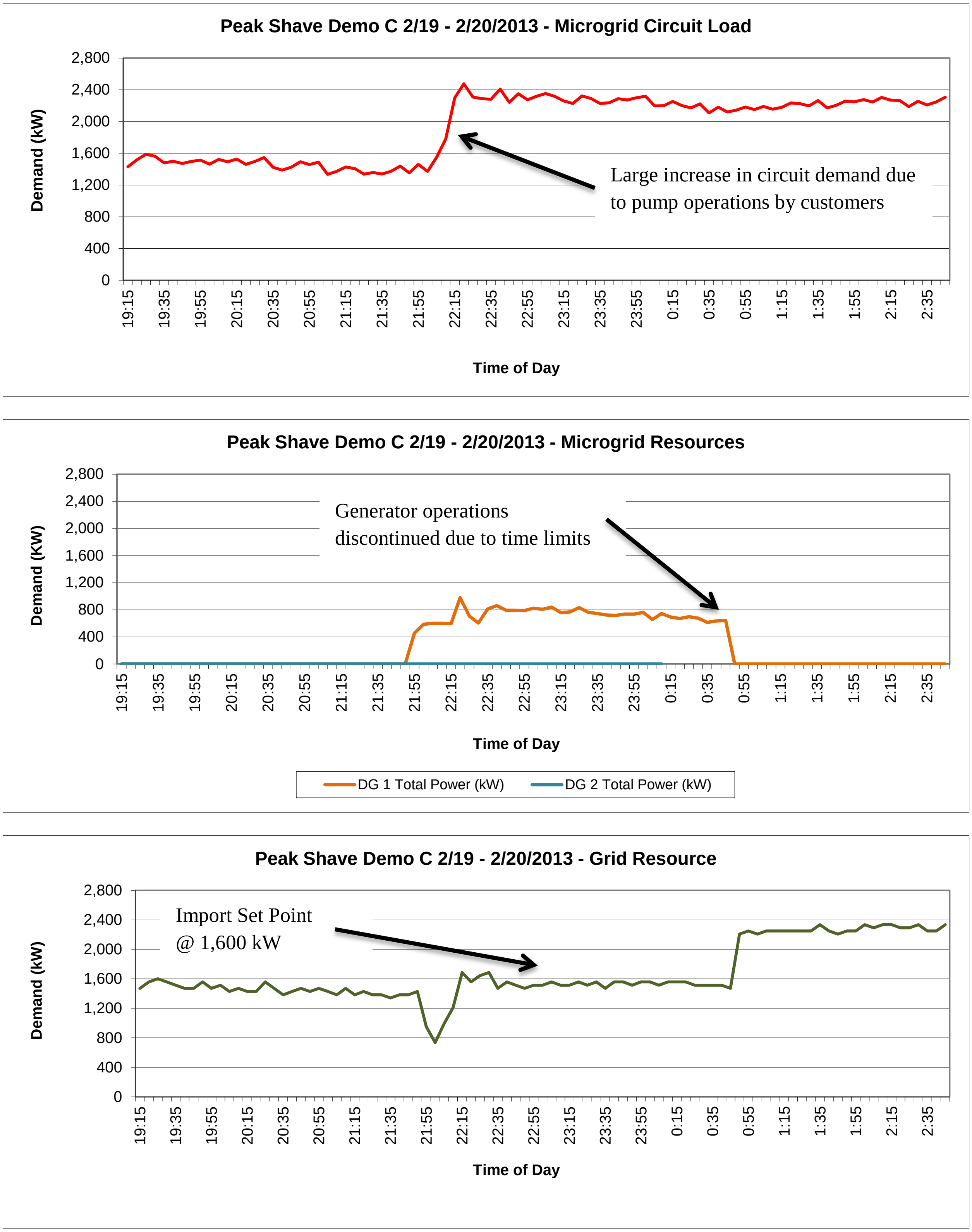
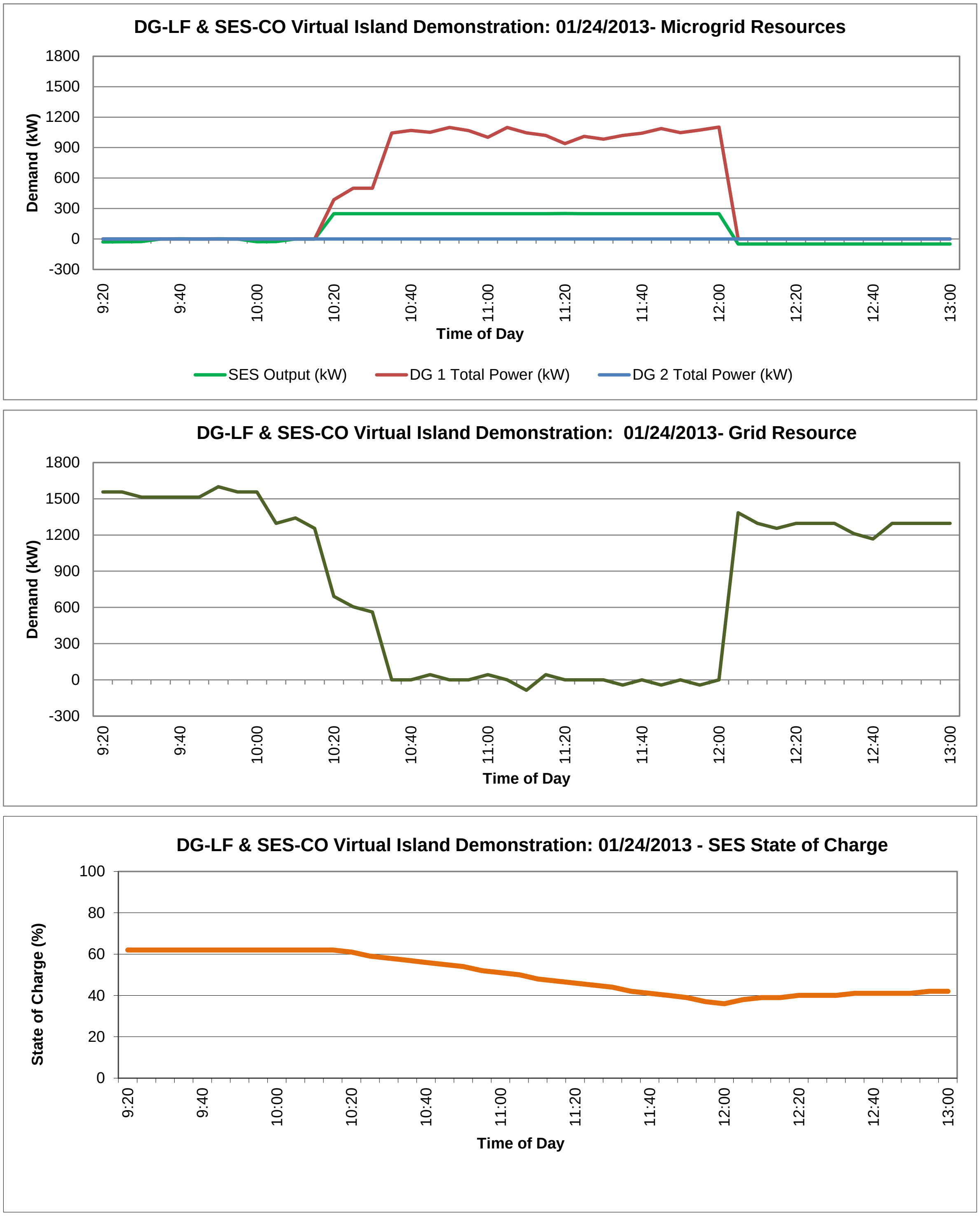


Figure 19: 15% Peak Reduction Demonstration

Additionally, Zero Flow at the breaker demonstrations proved that the Microgrid resources were able to carry the entire load on the circuit (approximately 1,500 kW in this example). The ability to meet the 1,500 kW load on circuit using Microgrid resources represents a 100% reduction in the actual load. Figure 20 on the following page shows the operation of one DG unit and the SES carrying the entire load of the Microgrid Circuit. Prior to the demonstration, the circuit load was a little more than 1,500 kW. The SES unit was operating in constant output at a rate of 250 kW. The DG was operating in load following mode to a set point of 0 kW at Microgrid Circuit Breaker. The combined operation of the DG and SES was able to carry the load on the circuit, thereby managing the power at the Microgrid Circuit breaker to near zero.

The middle graph shows that the range of load fluctuation at the Microgrid Circuit Breaker was -86 kW to + 43 kW. It is not clear if this fluctuation is due to the generator controls or the accuracy of the transducer being used as the control point. The transducer is bi-directional with a range of +/-8,000 kW. The variance of 129 kW represents an accuracy of 0.8%. This demonstration showed the ability to control the load to near zero at the breaker in a manner that the Microgrid should be able to transition to island mode while keeping the DG units operating in a stable manner.



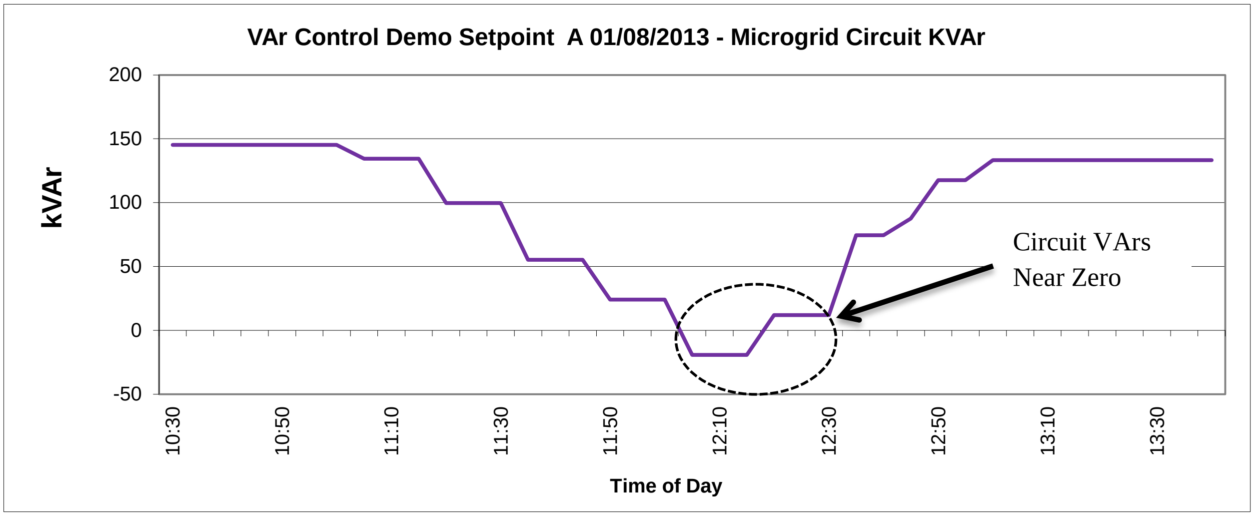
Note: LF=Load Following; CO=Constant Output

Figure 20: Zero Flow at the Breaker Demonstration (Virtual Island)

Objective 2: Demonstrate capability of Reactive power management

Results: Utilities use capacitors to compensate for reactive power caused by inductive loads. Inductive loads involve equipment such as motors whose operation causes reactive power to flow through the circuit. Capacitors provide reactive power compensation resulting in flatter voltage profile along the circuit, and less energy wasted from electrical losses in the circuit. The Borrego Springs Microgrid was designed with optimal reactive power management controls, provided by the operation of Microgrid resources (DG and SES). Multiple demonstrations were conducted using individual resources and a combination of resources to monitor the reactive power on the circuit, and operate the resources to manage the reactive power flow at the Microgrid Circuit Breaker. This section highlights two scenarios where the Microgrid resources were operated to manage the reactive power flow on the circuit.

Figure 21 on the following page provides a summary of the demonstration which was conducted on January 8, 2013. The Figure shows that during the first half of the operations the power factor was adjusted to appropriate set points that lowered the reactive power on the Circuit. Generator #2 was brought on line and operated in parallel with Generator #1 in order to have enough VAr capacity to cancel the kVArs at the Microgrid Circuit Breaker.



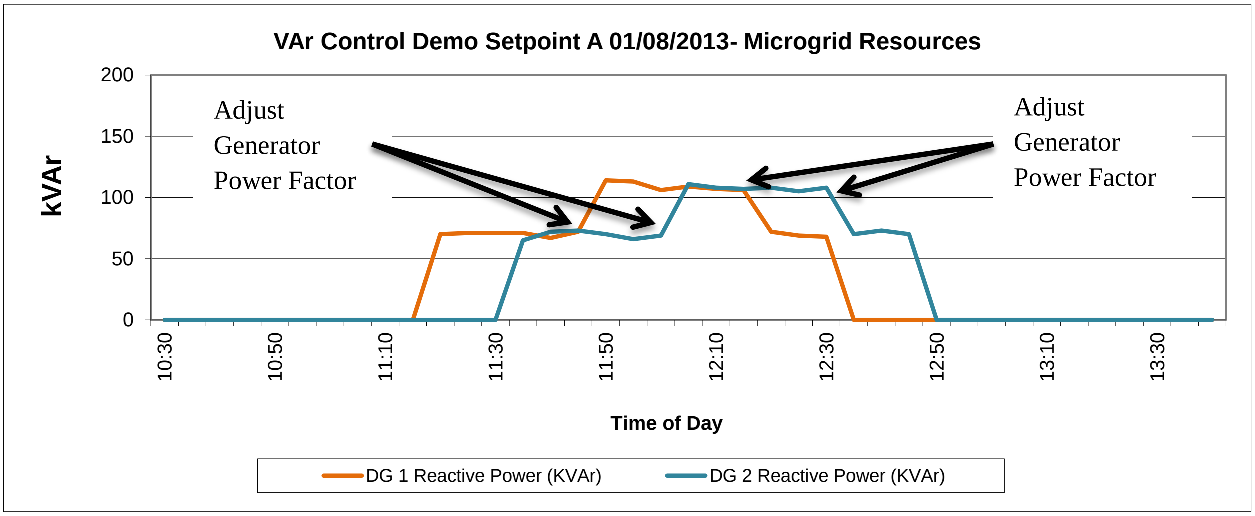


Figure 21: VAr Control Demonstration – Generators 1 and 2

Figure 22 on the following page provides a summary of the demonstration conducted on November 26, 2012. The demonstration includes the operation of DG #1and DG #2 separately and the SES unit operating during the entire demonstration. The DG units operated at a constant output of 1,000 kW and power factor of .98 which contributed 180 kVAr. The kVAr setting on the SES unit was set at various negative outputs (0, -200, and -400) for 15 minutes at each level and then set at positive outputs (200, 400, and 0) during the operation of each generator. The resultant reactive power as measured by the SCADA system was observed to move when the changes in the Microgrid resource were adjusted in 200 kVAr increments. Thus, the demonstrations showed that the reactive power as measured at the Microgrid Circuit Breaker by the SCADA device could be controlled to specific levels with the DG units in combination with the SES unit.

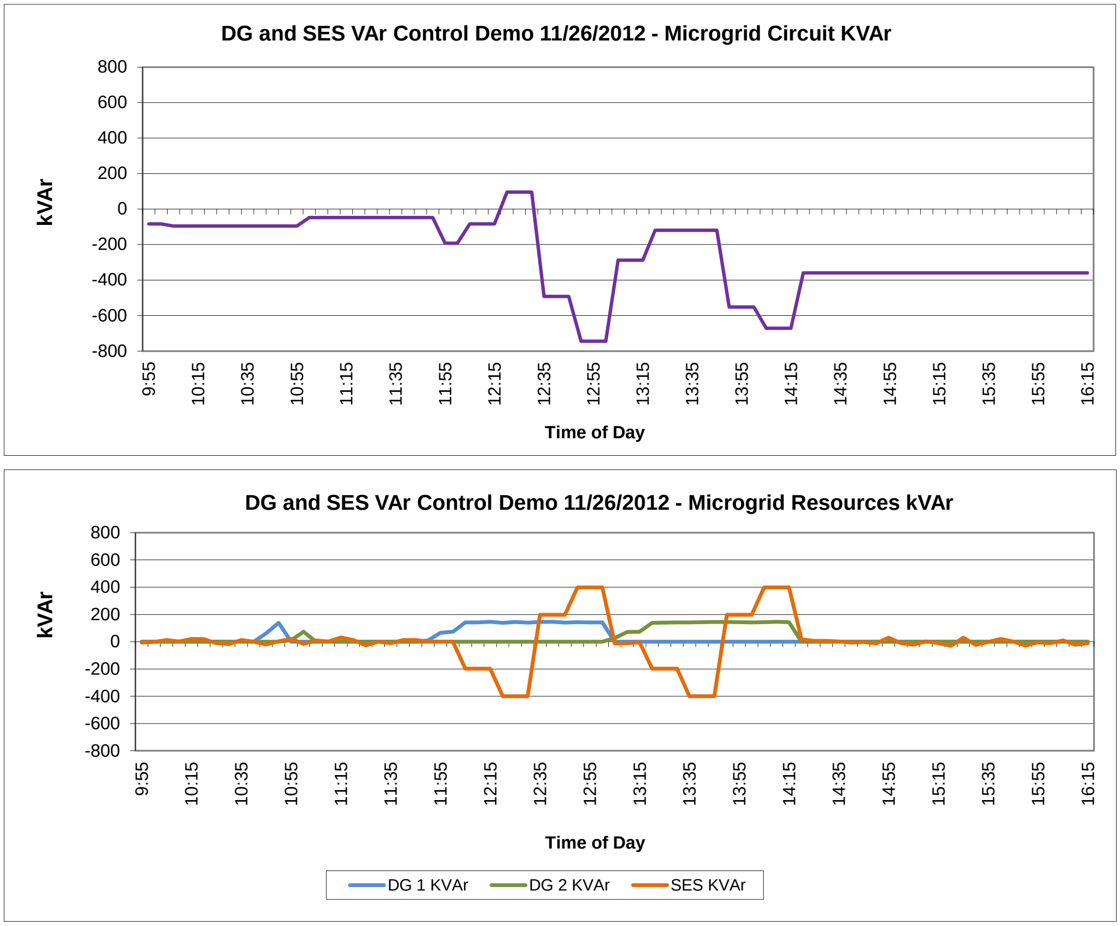


Figure 22: DG and SES VAR Mode Demonstration

Objective 3: Develop a strategy and demonstration of information integration

Results: The Borrego Springs Microgrid demonstration involved integration of various resources with various SDG&E system. The Microgrid Visualizer was designed as the primary vehicle for information integration between the Microgrid resources, and with other systems internal and external to SDG&E.

Figure 23 on the following page is a high-level overview of the Microgrid information technology architecture. This architecture leverages existing utility systems such as DMS, SCADA, and data warehouses and supports a scalable solution that is capable of integrating multiple Microgrids within the utility.

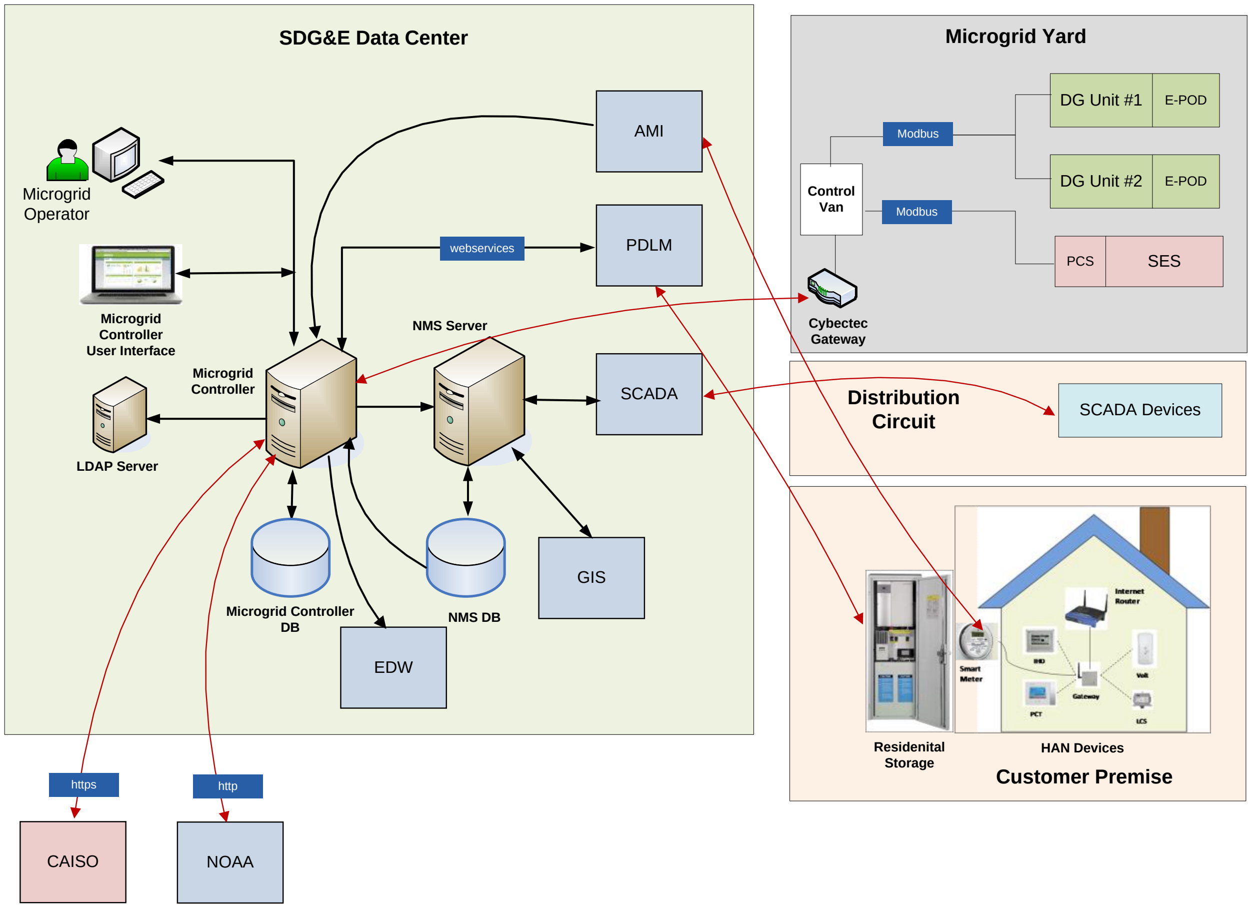


Figure 23: Microgrid Architecture

The Microgrid Visualizer provides centralized control in parallel and island modes of Microgrid operation. It operates over a longer time horizon and dispatches Microgrid resources by adjusting their operating set points to achieve operating and optimization objectives. The Microgrid Visualizer developed as part of this project was utilized as a core tool for remote operation of the Microgrid Resources during a majority of the demonstrations. The Visualizer is an important integration point to various utility systems like the OMS/DMS, SCADA system and the PDLM system. This tool was effectively used by Microgrid Operators to monitor and schedule the resources for operation in various modes to support Microgrid operations. The Visualizer required several external inputs to be loaded into the system manually. The Visualizer met the needs of the project to support planned demonstrations but is not sufficient to act as a standalone Microgrid Controller.

The IT infrastructure supporting the Microgrid is presented in Figure 24 on the following page. All components of the Microgrid IT infrastructure are secured behind multiple firewalls and include extensive intrusion protection controls and software. Each application was reviewed for compliance with extensive security requirements and company standards. Vendor hosted environments were reviewed to the extent that they expose utility assets to exploitation or intrusion.

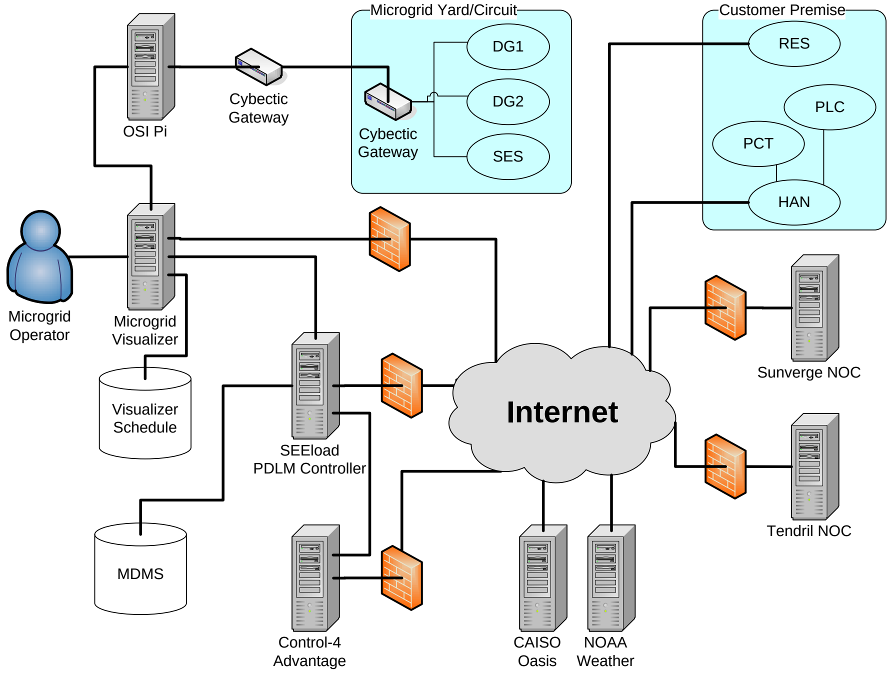


Figure 24: Microgrid IT Infrastructure

The Microgrid Infrastructure includes the following systems:

- Microgrid Controller (Visualizer) – The Visualizer is a custom developed solution deployed on OSI Pi Asset Framework. It includes the Scheduling Engine, Pricing Engine, Load Forecast Engine, and User Interface for monitoring and controlling the Microgrid devices. The Microgrid Controller includes integrations to internal and external systems. It communicates with the Microgrid devices via a pair of Gateways; one located in the data center and the other located in the Microgrid Yard. The Pricing Engine extracts Day-Ahead process from the CAISO Oasis application. Integration with the NOAA Web Site provides access to local weather forecast. The PDLM integration is used for communicating the wholesale Microgrid Price.
- PDLM Controller (SEELoad) – The PDLM Controller is the SEELoad COTS application from Lockheed Martin Smart Grid Solutions. This application includes integration with the CAISO Oasis system to retrieve Day-Ahead and Hour-Ahead Locational Marginal Price for the Microgrid pricing node. It also has an interface to the NOAA Weather site for local forecasts. Commands to customers' in-home devices are communicated through the Sunverge NOC (residential energy storage), the Tendril NOC (HAN devices), and the Control-4 Advantage application for that vendors Customer HAN devices. Finally, there is an interface from the Meter Data Management System to SEELoad to provide meter level consumption data for demand response event analysis.

- Network Operation Center (Tendril) – The PDLM Controller communicates all device commands to the HAN vendors NOC. The HAN vendors are responsible for the infrastructure, management and communication to the individual customer's HAN controller and devices. The NOC also provides customer device status information back to the PDLM controller.
- Network Operations Center (Sunverge) – The PDLM controller communicates commands for the residential energy storage through the vendor's (Sunverge) network operation center. As with the Tendril NOC, the Sunverge NOC manages all communication to the installed customer RES. Sunverge also provides PDLM with device status.

Objective 4: Develop a strategy and demonstrate the integration of Advanced Meter Infrastructure (AMI) into Microgrid operations

Results: The Borrego Springs Microgrid integrated with the Advanced Metering Infrastructure to provide interval meter data from the Smart Meter for Demand Response forecasting. The meter data was also used for Measurement and Verification of event data after Demand Response events were executed. This information helped analyze the actual load reduction versus predicted load reduction. This section describes the demand response forecast and post event analysis processes that utilized the meter data from the AMI system.

Demand Response Forecast - The primary objective of these demonstrations was to gather sufficient data to develop Demand Response forecasts with the required confidence levels within the PDLM Controller. The PDLM Controller develops a DR capacity forecast on a rolling 48-hour basis. The forecast is a learning algorithm that improves and converges over time. The baseline data initially utilized by the PDLM Controller vendor to develop the load forecast was based on typical Customer Baseline Load (CBL). The CBL data was developed by analyzing historical meter interval data, extracted from the AMI system. The forecast algorithm utilized the CBL to forecast DR Capacity on the Microgrid Circuit. The initial DR forecast did not converge for the expected Demand Response on the Microgrid Circuit. The PDLM Controller allowed for applying a correction factor that would reduce the CBL ratio, thereby reducing the DR Capacity Forecast. This resulted in the initial DR Capacity forecast that did not represent the true nature of DR on the Microgrid Circuit. The Microgrid team applied correction factors that provided a reasonable DR Capacity Forecast for the Microgrid Circuit. Figure 25 on the following page presents the initial DR Capacity forecast.

Figure 25: Initial DR Capacity Forecast

Figure 26 presents the DR Capacity Forecast provided by the PDLM Controller after application of correction factors to CBL.

Figure 26: DR Capacity Forecast – After Correction Applied to CBL

Post Event Analysis- Once a Demand Response event was completed successfully, the PDLM system conducts a post event Measurement and Verification analysis and results. This provides a feedback loop to refine the DR capacity estimates for future events. It also allows the operator to develop a confidence level for specific programs so that more accurate DR capacity estimates are possible.

The M&V process uses meter data from the AMI system to assess the actual load reduction from the DR event. This is necessary because not all HAN devices are aware of the load they carry. In some cases, the devices can record the actual load. For example, the plug load controller where the current flows through the device is able to capture the load data. This is reported to the device vendor NOC through the HAN Gateway. In the case of the PCT, however, the load measurable at the thermostat is not the same as the load of the compressor. Therefore, these devices cannot report any actual load. Most of the load reduction in a typical DR event comes from PCTs. The load of a central air conditioning system is significantly greater than that of a plug load controller for a lamp. Therefore, the actual load reduction can only be measured indirectly. One can only infer that the reduction was a result of the DR event.

The PDLM system calculates the actual load reduction by comparing the forecasted load to the actual load. Any difference is attributed to the devices participating in the DR event. The difference is considered the “actual load reduction.” The actual load reduction is then compared to the forecasted load reduction. Any difference in these values is used to adjust the expected load reduction for each device in future DR capacity estimates. The operator has the choice to accept and apply or reject the adjustments for future DR capacity estimates

The PDLM’s Analysis Module displays a table of completed events with the following summary data for each event:

- Event Date
- Event Start Time
- Event End Time
- Duration
- Predicted load reduction
- Actual load reduction
- Percent Participation
- Percent Opt Out

The predicted load reduction is forecast based specific programs. Each program has an “Estimated DR Capacity” based on:

- Starting assumptions for the device type (Customer Baseline Load)
- Historical actual results from DR events and analysis
- Temperature forecast (in the case of PCT)

The actual load reduction uses hourly interval Meter Data from which the PDLM records the consumption for the entire customer premises which is the difference between the CBL and the Actual Load on the customer premises. Customers were provided with incentives to participate in all DR and RTP demonstrations. However they had the option to opt out of events, if necessary. Percent Participation captures the percentage of customers that participated in the demonstration, while Percent Opt Out captures the percentage of customers that opted out of the demonstration.

Since the post event data represents the load impact of the aggregated customer base, further analysis was performed to understand the effect of DR events on individual customer load reduction. Hourly customer interval data was obtained from the AMI system for customers that participated in the DR demonstrations. The data was analyzed to see the trend of customer load on the days of the event and an average of the customer load over 3-days or 7-days prior to the event. This analysis identified several instances of actual load reduction in customer homes during the DR demonstrations. In absence of the DR events, the customer load would have remained higher. Figure 27 presents the load profile for certain customers who participated in the DR events who had significant load reduction of during the DR events. The charts below present two load curves for comparison:

- Event Day Load Curve (red line)
- Average Load for Days Prior to Event (black line)
- Figure 27 presents the results of a three hour DR event that was executed between 14:00 and 17:00. The customer had a slight reduction in load during the first and second hours of the event and then a more substantial reduction in the third hour of the event. Overall, the customer load was higher than their average load when the event began and was lower than their average load at the end of the event. The load reduction from the beginning of the event to the end of the event was 6.6 kW

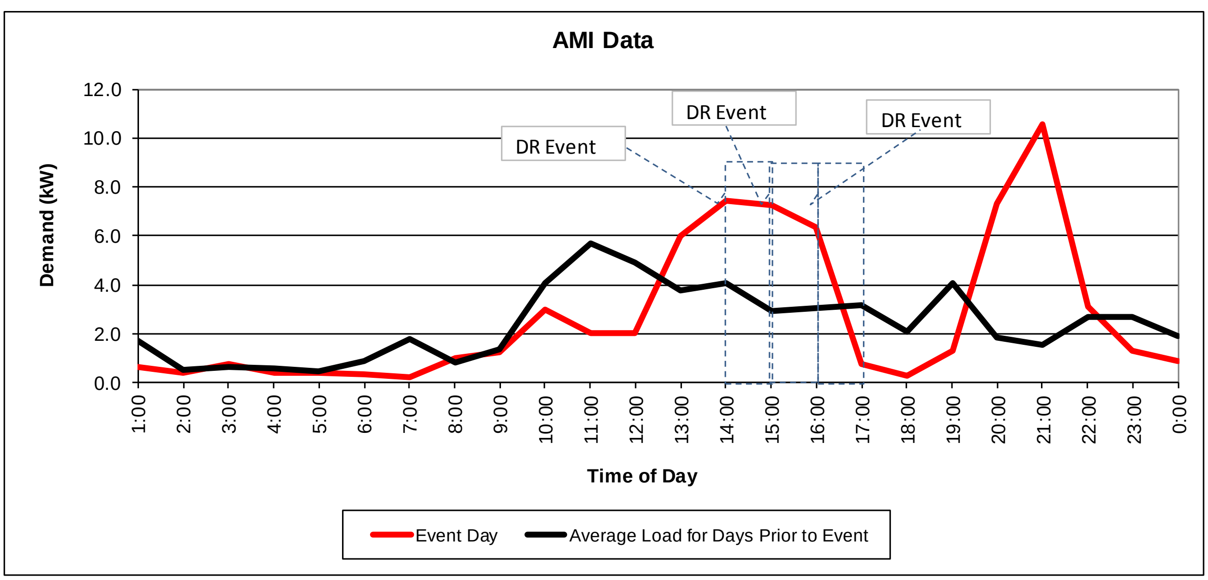


Figure 27: Example - Customer Load Reduction During DR Events

Objective 5: Develop a strategy and demonstrate 'self-healing' networks

Results: The FLISR was first modeled for the Microgrid Circuit and was tested in a development platform and then moved into production. For a detailed assessment of the improvement in response to unplanned outage, the switch plans were analyzed for all outages on the Microgrid Circuit. The outages were analyzed to identify those that were representative of events that could be impacted by FLISR. This eliminated outages that could not be switched using available SCADA devices. Nine representative outages were identified and analyzed, to assess the expected benefit on the results of simulation compared to actual historic outage operations results.

1. Momentary Outage of Less than 1 Minute Caused by Weather
2. Sustain Outage Caused by Motor Vehicle Collision
3. Sustained Outage Caused by Damaged Pole
4. Sustained Outage Caused by Tree Overhead Wire Down
5. Sustained Outage Caused by Equipment Failure and Overhead Wire Down
6. Sustained Outage Caused by Overhead Wire Down
7. Sustained Outage Caused by Overhead Equipment Failure
8. Sustained Outage Resolved by Auto-Sectionalizer
9. Sustained Outage Caused by Earthquake

Based on demonstrations and performance metrics observed in the Microgrid Circuit, FLISR has the opportunity to improve Customer experience and circuit reliability through:

- Reduced customer duration minutes
- Reduced number of customers included in sustained outages
- Improve distribution operators efficiency

The FLISR system impact on historic outages described above includes:

- Three events that would not have changed
- One momentary event that would have been completed two minutes faster
- Four sustained events that would have had a subset of customers converted from a sustained to a momentary outage and reduced duration significantly
- One sustained outage that would have been converted to a 2 minute momentary outage provided that earthquake policy could accommodate FLISR operation

Improving the efficiency of distributions operators is one of the significant contributions of FLISR. It is difficult to quantify these efficiency benefits. Operators are responsible for multiple tasks. They schedule time throughout the day to manage the distribution network for planned work by the construction crews. Distribution operations must be staffed to support ongoing planned activity. They must also have the capacity to respond to unplanned events such as outages.

FLISR improved efficiency in several ways. The essence of the improvement is that the distribution operators are presented with a simpler contained outage. Rather than dealing with the entire circuit, the operators only deal with the isolated faulted segment of the circuit. Also, the operator does not have to deal with the switch planning and execution for isolation and restoration. This allows the operator to focus efforts on the high value efforts to direct and support the assigned troubleshooting and repair crews.

Benefits of reducing and simplifying the process extends to unrelated tasks assigned to the distribution operators. Interruptions to ongoing planning and workflows are fewer and shorter. This allows the operators to return to planned activities more quickly. Their productivity when returning to these tasks is higher when the interruptions are shorter and simpler.

Objective 6: Develop a strategy and demonstrate the integration of an OMS/DMS into Microgrid operations

Results: The Microgrid Visualizer developed as part of this project was utilized as a core tool for remote operation of the Microgrid Resources during a majority of the demonstrations. The Visualizer is an important integration point to various utility systems like the OMS/DMS, SCADA system and the PDLM system. This tool was effectively used by Microgrid Operators to monitor and schedule the resources for operation in various modes to support Microgrid operations. The Visualizer required several external inputs to be input into the system manually. The Visualizer met the needs of the project to support planned demonstrations but is not sufficient to act as a standalone Microgrid Controller.

Figure 28 presents a high level view of the various systems integrated together to integrate with the Microgrid Visualizer.

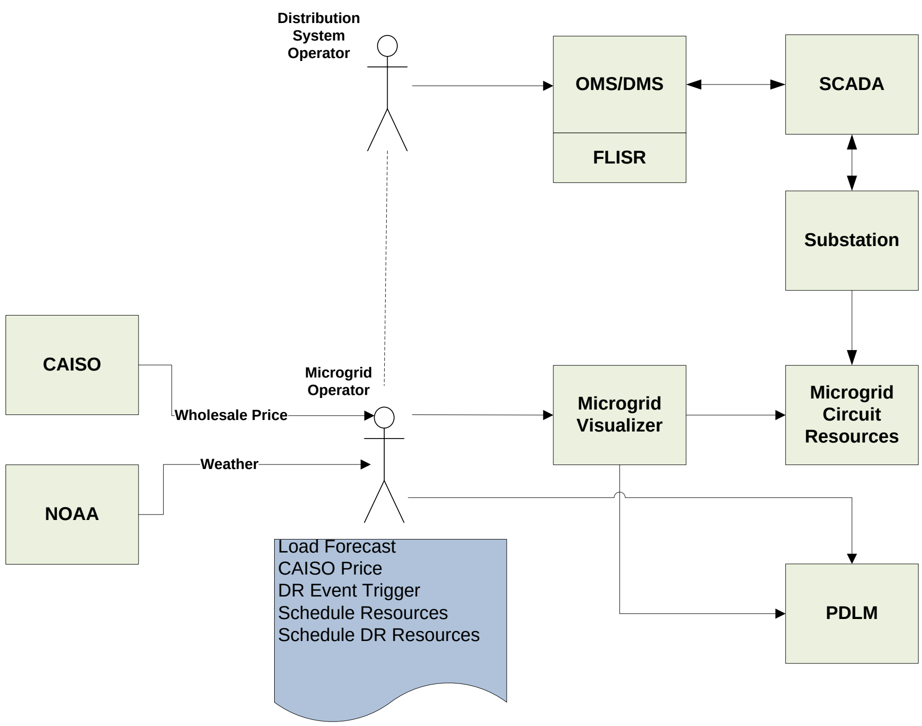


Figure 28: Interaction between Distribution System Operations and Microgrid Operations

The Distribution System Operator (DSO) oversees the operational functions of the entire distribution network through a newly implemented OMS/DMS system that is also is interfaced to SCADA system. The OMS/DMS system supports distribution system operations and also includes tools for Volt/VAr management, validation of switching plans as well as FLISR activities.

The Microgrid Visualizer was developed as the system of record to monitor and schedule operations of the Distributed Energy Resources within the Microgrid. The Microgrid Visualizer was created based on an iterative process that began by developing business and technical functional requirements for a Microgrid controller. As part of the Microgrid demonstration, the PDLM system was developed to manage customer-owned resources for DR. The Microgrid Visualizer interfaces with the PDLM system, and provides triggers to the PDLM system which can schedule and dispatch DR resources as needed.

The Microgrid Operator is the point of contact to oversee and manage the control and monitoring functions for the Microgrid. The Microgrid Operator manages the Visualizer and the PDLM system. The Microgrid Operator is also responsible for translating the data from CAISO (Wholesale Price to retail price conversion) and NOAA (weather data) to actions that affect Microgrid system operations. The major activities of the Microgrid operator include:

- Develop a daily load forecast and input into Microgrid Visualizer
- Collect the appropriate day ahead CAISO Wholesale Price and input into the Microgrid pricing model
- Schedule Microgrid Resources to optimize Microgrid operations
- Create DR Event Trigger within the PDLM System as needed
- Schedule DR Resources within the PDLM System

Objective 7: Demonstrate the capability to use automated distribution control to intentionally island customers in response to system problems.

Results: The Borrego Springs Microgrid was designed to operate the Microgrid in island mode. Multiple demonstrations were performed that proved the Microgrid can seamlessly transition into island operation and seamlessly transition back to parallel mode of operation. This section provides information on the demonstrations that were conducted island the Microgrid with real customers.

The key objectives of the island demonstrations are as follows:

- Operate the Microgrid Resources to a condition of zero power flow at the breaker and open the Microgrid Circuit Breaker while maintaining stability of the Microgrid Circuit
- Validate the isochronous operation of the DG units
- Validate stable operation of the islanded Microgrid Circuit while operating the DG and SES units together

- Quantify the level of reactive power support that the SES can provide to the DG units while in island operations
- Validate the seamless transition of the Microgrid from island mode back to the grid

Overall there were seven Island demonstrations that were conducted as presented in Table 9. For the first two Island demonstrations, three separate sub-demonstrations were conducted that included:

- Island with Distributed Generators Only
- Island with Distributed Generators and Substation Energy Storage together
- Island with Distributed Generators and Substation Energy Storage for VAr Control

Table 9: Island Operation Demonstrations

Mode of Operation	Microgrid Resources			Demo Description	Control Settings	Demo Date	Start Time	End Time	Control Interface
	Gen1	Gen 2	SES						
Island Test	X	X		Island Demonstration w/DG Only	Gen 1 and Gen 2	2/13/2013	9:20	10:35	Local
	X	X	X	Island Demonstration w/DG and SES	Gen 1, Gen 2 and SES (Real Power)	2/13/2013	10:45	11:40	Local
	X	X	X	Island Demonstration w/DG and SES VAr	Gen 1, Gen 2 and SES (Real Power and Reactive Power)	2/13/2013	11:50	12:40	Local
	X	X		Island Demonstration w/DG Only	Gen 1 and Gen 2	2/27/2013	9:00	10:15	Local
	X	X	X	Island Demonstration w/DG and SES	Gen 1, Gen 2 and SES (Real Power)	2/27/2013	9:00	10:10	Local
	X	X	X	Island Demonstration w/DG and SES VAr	Gen 1, Gen 2 and SES (Real Power and Reactive Power)	2/27/2013	10:15	11:45	Local
	X	X	X	Remote Island Demonstration	Gen 1, Gen 2 and SES (Real Power and Reactive Power)	3/13/2013	10:00	14:20	Remote

Island with Distributed Generators Only - Island Operation with DG only was conducted as the first Island demonstration because the generators had been modified with controls to specifically operate in an isochronous mode of operation. Also, the demonstrations were conducted at a time when the load on the Microgrid Circuit could be carried by the two 1.8 MW generator units. The specific objectives of this demonstration included:

- Demonstrate Generator operation in Isochronous mode for
  - Load Control
  - Voltage Control
  - VAr Control
  - Frequency Control
- Demonstrate Stability of Operation of the Microgrid Circuit while in Island
- Demonstrate Seamless Transitions of the Microgrid Circuit for the following:
  - Generator synchronization to the grid
  - Separation of Microgrid from the grid
  - Return of Microgrid back to the grid

The Sequence of Operation to operate Microgrid Circuit in Island mode with DG only included:

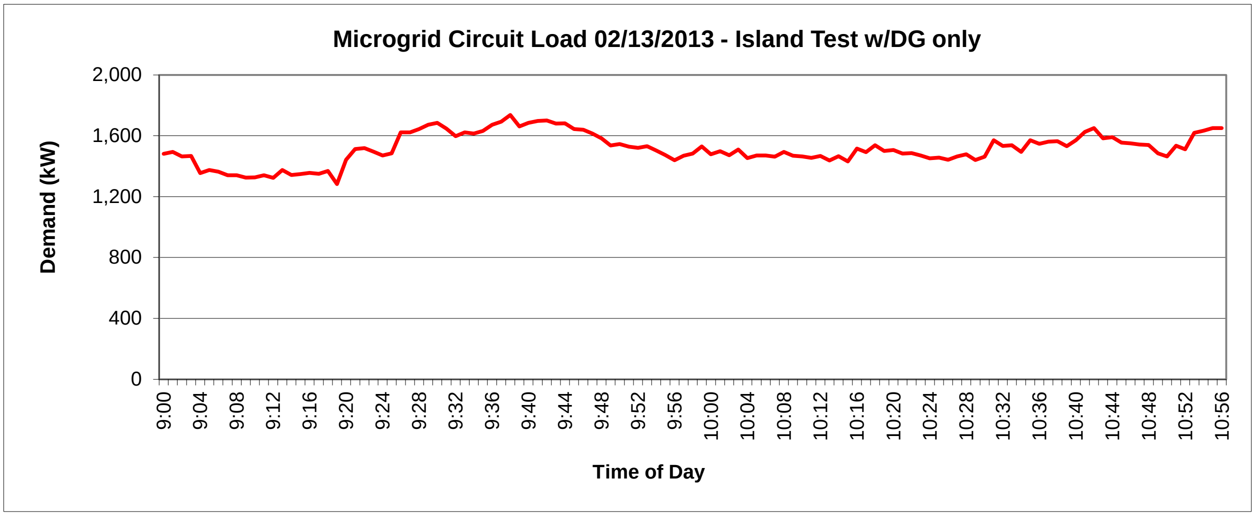
- Switch off the line capacitor on the Microgrid Circuit
- Synchronize generators to match grid voltage and frequency

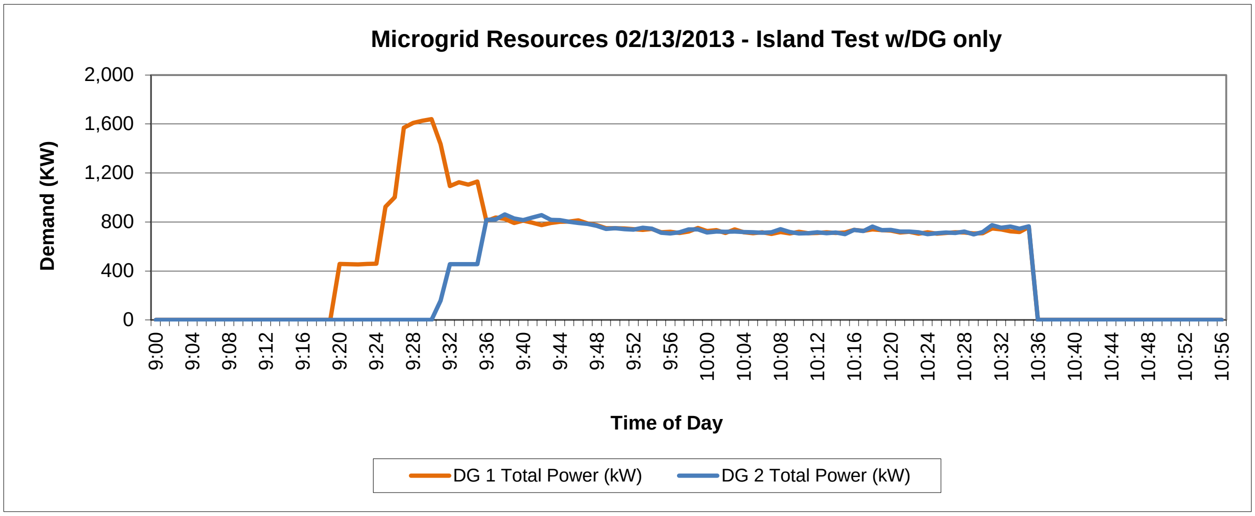
- Set the generators in load following mode with set point of zero (zero power flow across the Microgrid Circuit Breaker)
- Once the power flow across the Microgrid Circuit Breaker is zero, request island permissive bit.
- Microgrid Circuit Breaker opens
- Observe the generator controls to automatically transition to the isochronous mode
- Operate in Island Mode for approximately one hour
- Once the Island operation is successfully operational for one hour, synchronize back to Grid (upstream of Microgrid Circuit Breaker)
- Microgrid Circuit Breaker closes
- Leave Generators running in parallel for next demonstration

The above sequence of operations was a result of close cooperation between the Microgrid Operator and the Distribution System Operators.

The Island Operations using only the generators was demonstrated successfully by locally controlling the generators using the Microgrid Visualizer. The first two times that the island mode was demonstrated, the Microgrid Operator controlled the equipment from the Control Van in the Microgrid Yard. The operations were coordinated with a line crew to manually turn off the fixed line capacitor at the beginning of the demonstration and to be available for other support if needed.

Figure 29 on the following page presents a summary of the island demonstration on February 13, 2013. For this demonstration, DG #1 was initially synchronized with the Microgrid Circuit with a load of approximately 1,600 kW. Then DG #2 was synchronized with the Microgrid Circuit and the load was shared equally by both generators. The two units operated in load following with a set point of 0 kW at the Microgrid Circuit Breaker from 9:27 AM to 9:40 AM when the Distribution Operator sent a permissive bit to island the Microgrid Circuit. The Microgrid operated as an island for 90 minutes. The Distribution System Operator set the permission in the relay for the generators to synchronize back to the grid. The synchronization took approximately 45 seconds, (the controls are configured for 2-minute time-out). Once the Microgrid Circuit Breaker was closed, the two generators operated again in load following with a set point of 0 kW and remained in this mode until 10:37 AM.





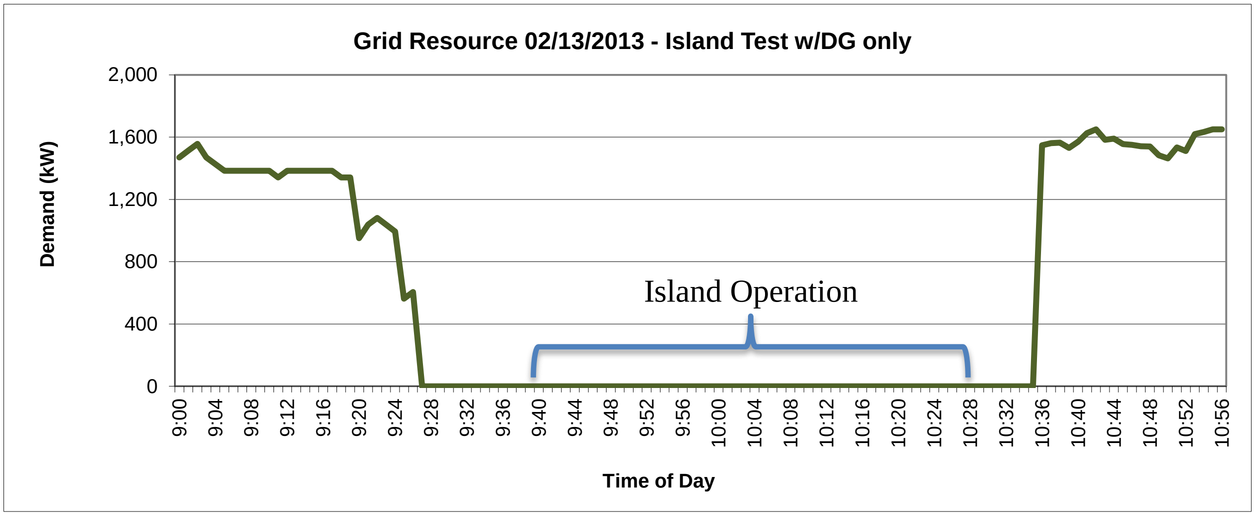


Figure 29: Island Demonstration with DG Only

Figure 30 shows the DG #1 controls while operating in an island demonstration. The unit is operating at 970 kW, 479 volts, a power factor of 0.98 lagging, and a frequency of 60.02 Hz.

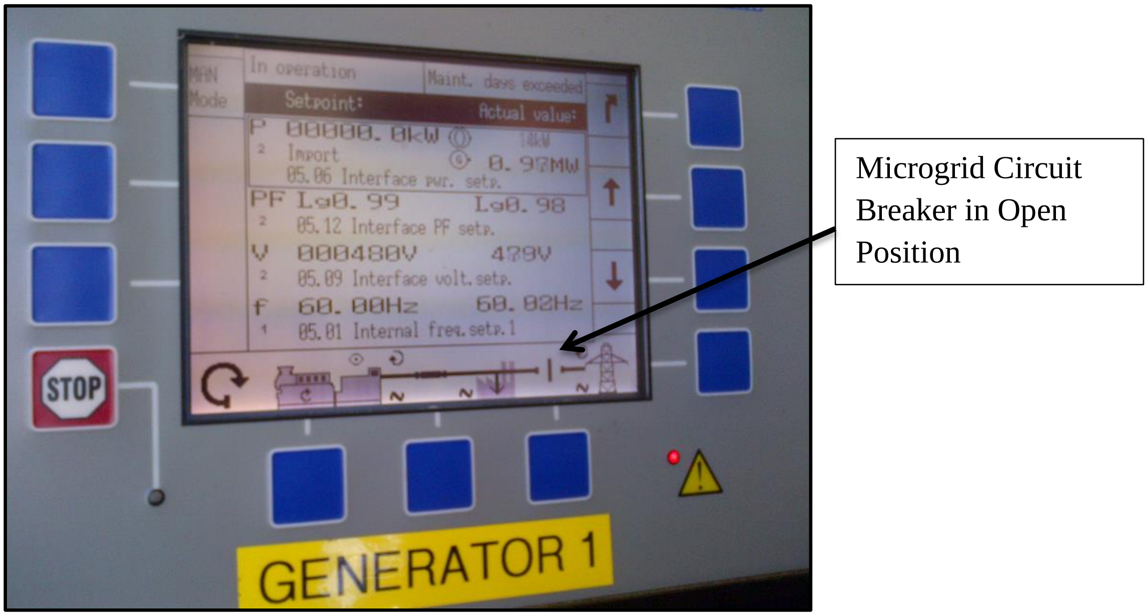


Figure 30: Generator Control Display in Island Operations

Figure 31 presents the generator synchroscope during the transition from island to grid connected. The synchronization process took less than 45 seconds to complete. The breaker closes when the synchronization indicator is stable at the 12 o'clock position on the circle.

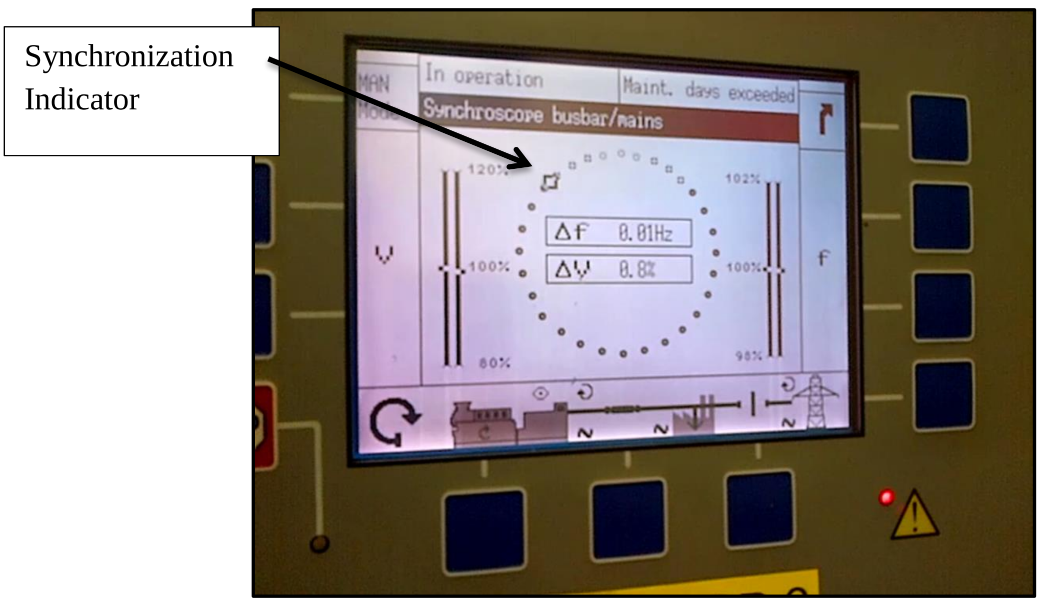


Figure 31: Generator Synchroscope during Transition from Island

Additional monitoring was conducted during the island demonstrations to evaluate the voltage on the 12 kV Microgrid Circuit during the various transition points. Figure 32 on the following page shows the voltages on the three circuit phases as the DG units synchronize to the grid and when the Microgrid Circuit Breaker opens. The data shows that there is a perturbation of voltages at each transition with the largest occurring when the circuit breaker opens. The fluctuation of voltage when the circuit breaker opens is about 70 volts with represents a 0.6% voltage fluctuation.

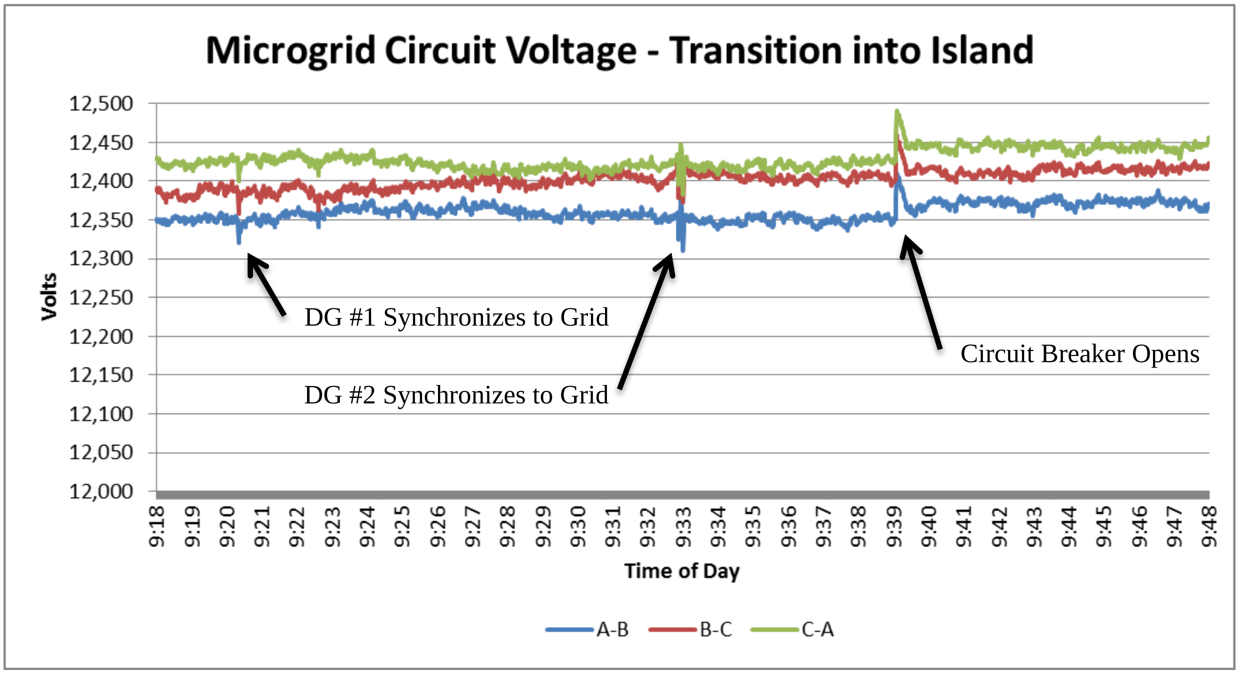


Figure 32: Microgrid Circuit Voltage when Transitioning into Island

Figure 33 on the following page shows the voltages on the three phases of the circuit when the Microgrid Circuit Breaker closes. The data shows that there is a perturbation of voltages at the transition. Both figures show that the voltages are slightly higher when the generators are operating in the island. At all times, the voltages are within the standards of delivery to the customers.

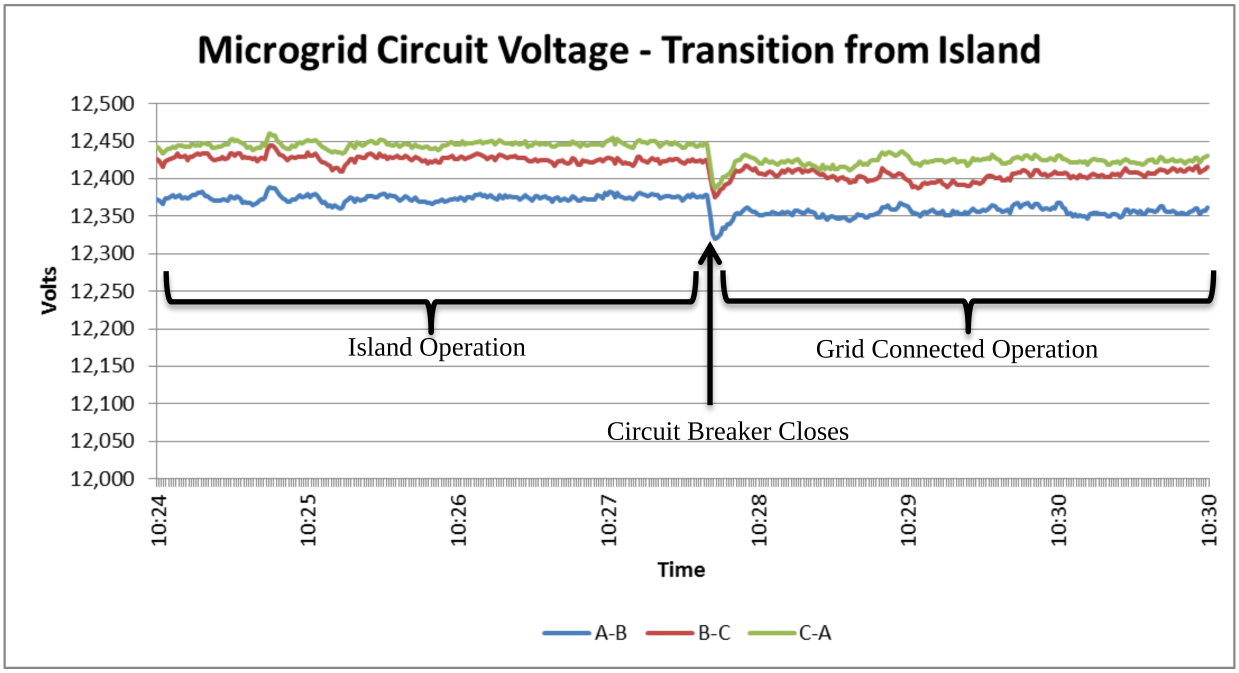


Figure 33: Microgrid Circuit Voltage when Transitioning from Island

Island with Distributed Generation and SES - With the successful Island Demonstration of the Microgrid Circuit with DG only, the next objective was to demonstrate Island Operation with simultaneous operation of the DG and SES units. Additional objectives of this demonstration include:

- Demonstrate Stability of Operation of the Microgrid Circuit while in Island
- Demonstrate ability to vary SES discharge rates in Island mode
- Demonstrate ability to transition the SES to charge mode in Island operation
- Demonstrate ability to vary charge rates in Island mode
- Demonstrate Seamless Transitions of the Microgrid Circuit for the following:
    - Generator synchronization to the grid
    - Separation of microgrid from the grid
    - Return of Microgrid back to the grid

Methodology – The Sequence of Operation to operate Microgrid Circuit in Island mode with DG and SES included:

- Parallel SES with the Microgrid Circuit in discharge mode
- Parallel DG units with the Microgrid Circuit in load follow with set point of zero (zero power flow across the Microgrid Circuit Breaker)
- Once the power flow across the Microgrid Circuit Breaker is zero, request island permissive bit.
- Microgrid Circuit Breaker opens
- Operate in Island Mode with DG and SES for approximately one hour

- SES Operation while in Island Mode:
    - Discharge SES at 100 kW for 15 minutes
    - Ramp SES down to 0 kW in 10 kW steps over a one minute period
    - Operate SES at 0 kW for 15 minutes
    - Ramp SES down to -100 kW (charge mode) in 10 kW steps over a one minute period
    - Charge SES at 100 kW for 15 minutes
    - Ramp SES up to 100 kW in 10 kW steps over a two minute period
    - Discharge SES at 100 kW for 15 minutes
- Once the Island operation is successfully operational for one hour, synchronize back to Grid (upstream of Microgrid Circuit Breaker)
- Microgrid Circuit Breaker closes
- Leave Generators running in parallel for next demonstration

The Island Operations with DG and SES only was demonstrated successfully by controlling the generator and SES locally using the Microgrid Visualizer from the Control Van in the Microgrid yard. The control approach demonstrated that the DG and SES can be operated simultaneously to meet a forecasted load. The DG was operated in load following and while the SES was programmed to operate within specified set points. Figure 35 on the following page shows that the generators and SES were able to share and meet the load over the range of operation.

The SES was operated in both charge and discharge modes of operation and the set points were also altered during the demonstration. The point of adjusting the SES set points was to cause small rapid changes in the load seen by the DG units and observe if the stability of the island mode operation was affected by these changes. Figure 34 presents a screen shot of the Microgrid Visualizer during island operation with both DG units and the SES operating.

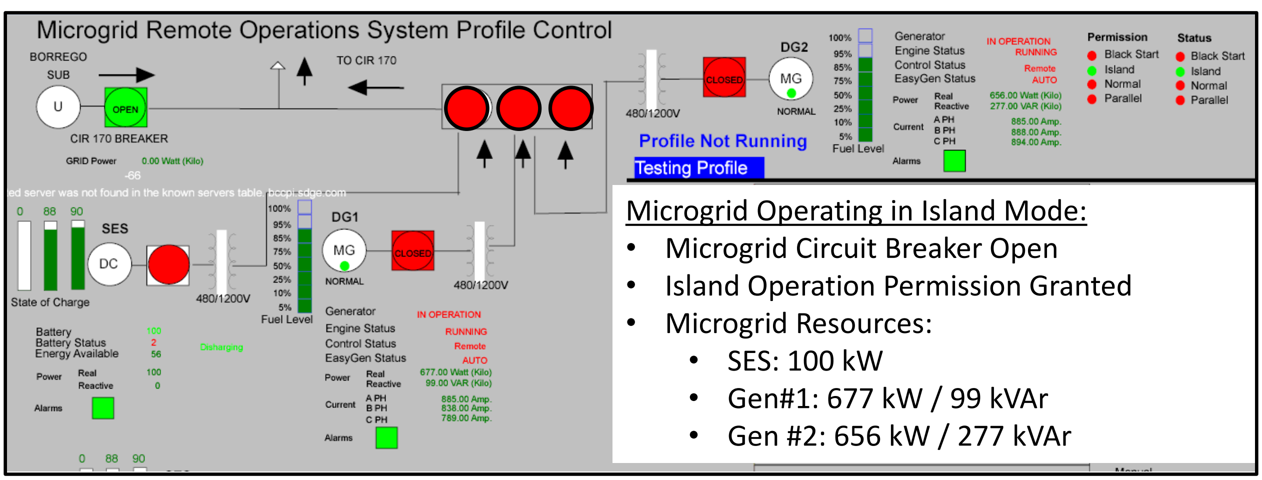


Figure 34: Microgrid Visualizer during Island Operations

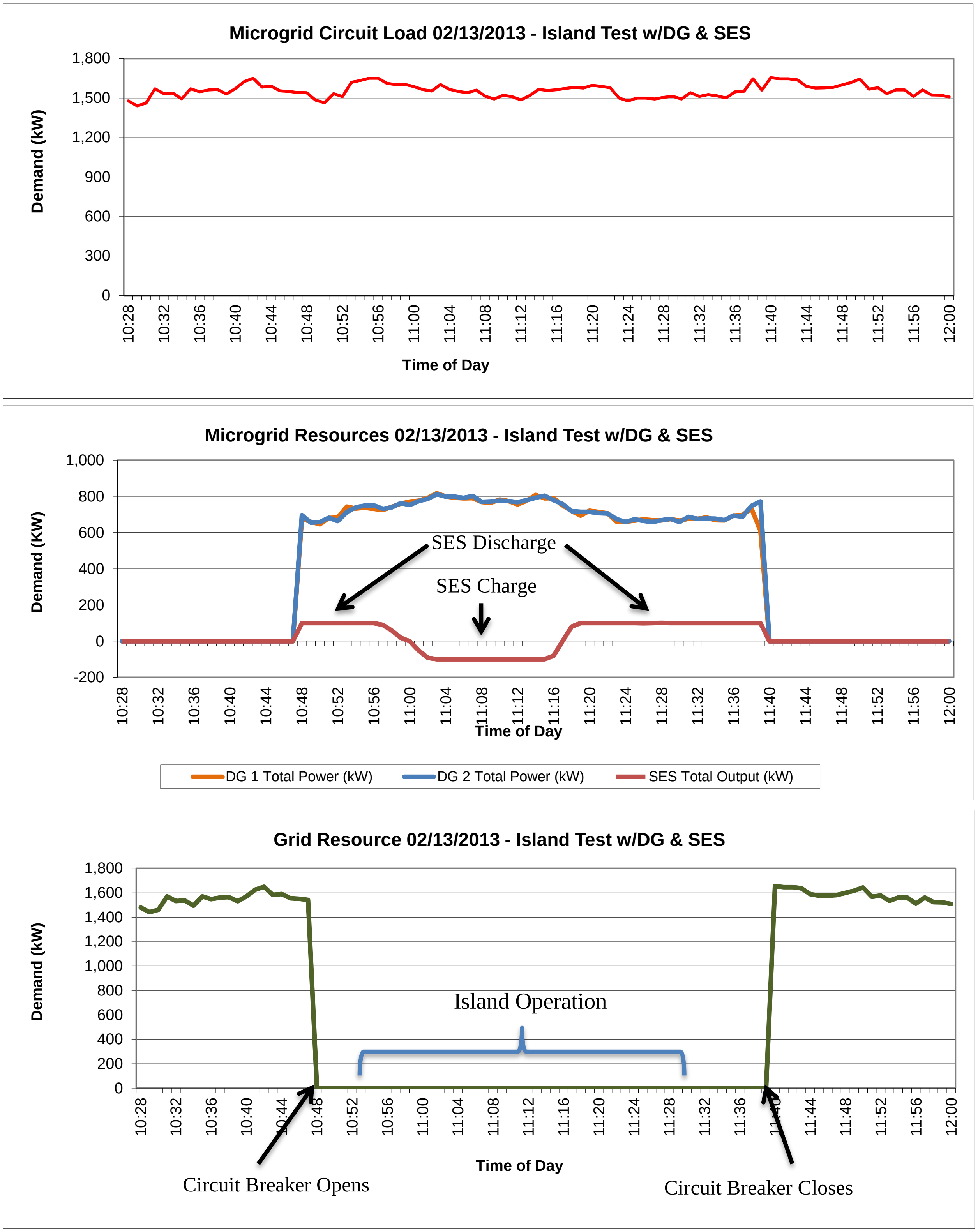


Figure 35: Island Demonstration with DG and SES

Island with Distributed Generation and SES (VAr Control) - The primary objective of this particular islanding demonstration is to evaluate how the Microgrid resources can effectively manage reactive power in island operation. This demonstration builds on the simultaneous operation of DG and SES in Island mode to evaluate options for VAr control during Island operation. In isochronous operation, the DG units supply the reactive power required by the circuit loads which can be high when the large pumps are operating. The goal of this scenario is to evaluate the ability to have the DG units provide a majority of the real power to the Microgrid and to have the SES unit provide a majority of the reactive power. This method of operation is expected to result in a lower cost of operation and provide the ability to potentially operate the generators longer since they will be consuming less fuel by operating more efficiently. Additional objectives of this demonstration include:

- Demonstrate Stability of Operation of the Microgrid Circuit while in Island
- Demonstrate ability to conduct SES operations (on/off) in Island mode
- Demonstrate ability to control VArs in Island mode

The Sequence of Operation to operate Microgrid Circuit in Island mode with DG and SES managing the VAr on the circuit included:

- Parallel SES with the Microgrid Circuit in idle mode
- Parallel DG units with the Microgrid Circuit in load follow with set point of zero (zero power flow across the substation breaker)
- Once the power flow across the substation breaker is zero, request island permissive bit
- Microgrid Circuit Breaker opens
- Operate in Island Mode with DG and SES for approximately 45 minutes
- Set SES in Base Mode
- Ramp SES to 100 kW
- Place the SES in VAr control mode and adjust VAr output to minimize VArs on the circuit
- Once the Island operation is successfully operational for 45 minutes, operate the SES in idle mode
- Synchronize back to Grid with generator controls at the Microgrid Circuit Breaker
- Microgrid Circuit Breaker closes

The Island Operation with DG and SES controlling VArs was demonstrated successfully by locally controlling the generator and SES from the Control Van in the Microgrid yard using the Microgrid Visualizer. The two DGs operated in isochronous mode and the SES operated in VAr mode to provide the required VArs on the circuit. The SES was not able to carry the full VAr load on the circuit; however, the use of SES for VAr control meant that the generators could be operated at a higher power factor of 0.95, thereby carrying more load on the circuit. The SES was initially operated in idle mode, then ramped up to discharge at 100 kW and was finally placed back in idle mode. This demonstrated the capability to operate the SES in Island mode without affecting the stability of the Microgrid Circuit. Finally, the Microgrid Circuit seamlessly transitioned from Island operation to grid parallel operation within 45 seconds.

Figure 36 shows that the generators are operating by themselves at a power factor approximately 0.90. At 12:00 PM the SES reactive power output was set to 100 kVAr, which allowed the generators to operate at a power factor of approximately 0.92. At 12:10 PM the SES reactive power output was increased to 275 kVAr, which improved the generator power factor to 0.95. This demonstrated that the SES could manage VAr to the point where the generators could operate at improved power factors. The duration of the demonstration was from 11:40 AM to 12:45 AM. The Microgrid Circuit load ranged between 1,650 kW and 1,400 kW during the demonstration.

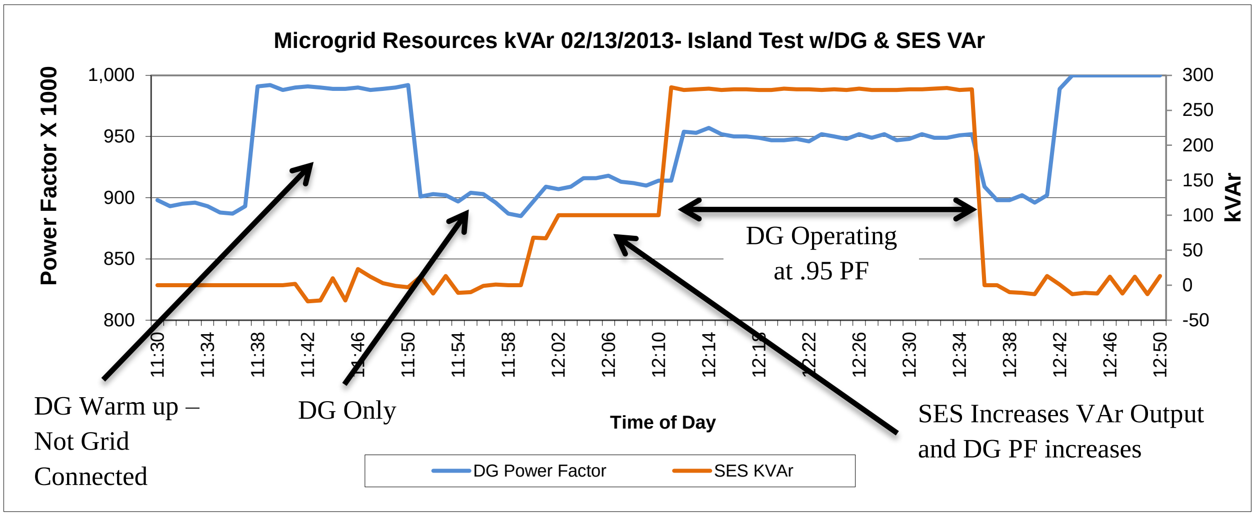


Figure 36: Island Demonstration with DG using SES for VAr Control

Objective 8: Develop information/tools addressing the impact of multiple DER technologies.

Results: The Microgrid was designed to operate multiple DER technologies that integrated with the Microgrid Visualizer. Various information tools and processes were developed that assisted in Microgrid operations.

Microgrid Visualizer –The Microgrid Visualizer interfaces with the various resources on the Microgrid Circuit, as well as various systems at SDG&E. Each individual resource in the Microgrid Circuit is equipped with its internal control system. Various systems at SDG&E like SCADA, OMS/DMS, and PDLM system have their own user interfaces that provide into the control functions that are available to the operator. With so many user interfaces to monitor, it would have been difficult for the Microgrid Operator to get an overall picture of the information flow across these systems.

The Microgrid Visualizer provides a consolidated user interface for the Microgrid Operator to dispatch resources and monitor equipment operation. When a desired set of operations are needed for the Microgrid, the Microgrid Operator selects, loads, and activates the appropriate schedule or profile. Figure 37 presents the Microgrid Visualizer user interface when a scheduled operation is being executed. This interface provides the Microgrid Operator with the status and operating parameters of each of the Microgrid Resources as well as the scheduled operation. This provides feedback to the Operator whether or not the Microgrid is operating as anticipated.

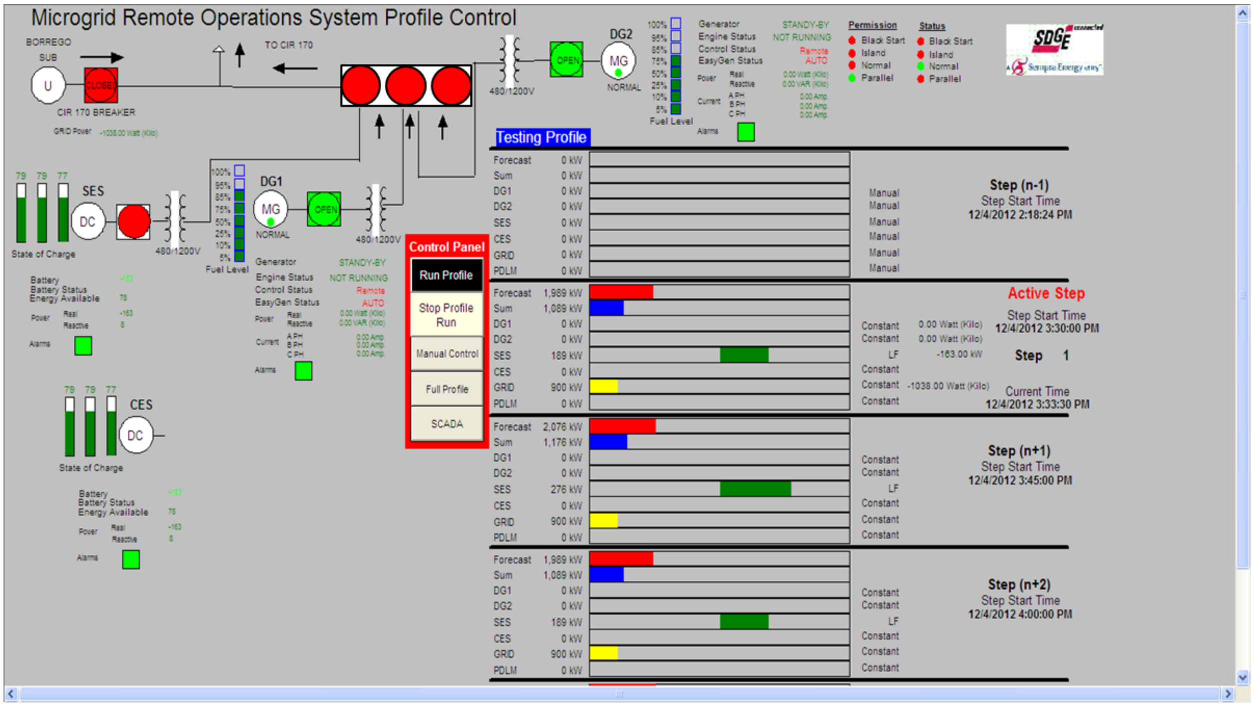


Figure 37: Microgrid Visualizer User Interface

Load Forecast - A load forecast model was developed using August 2012 data to help support Microgrid operations and demonstration planning. The load forecast is based on a multivariable linear regression using the following variables:

- Time of day (military format with no colon)
- Outside ambient dry bulb air temperature forecast (°F)
- Pump schedule flag (1's and 0's, set to 1 from 11:00 PM to 5:00 AM)
- Average of three previous weekday's load at the same time day (MW)
- Average of three previous weekday's ambient dry bulb Air temperatures at the same time (°F)

Figure 38 presents a sample load forecast versus actual load that was observed for 2/6/2013.

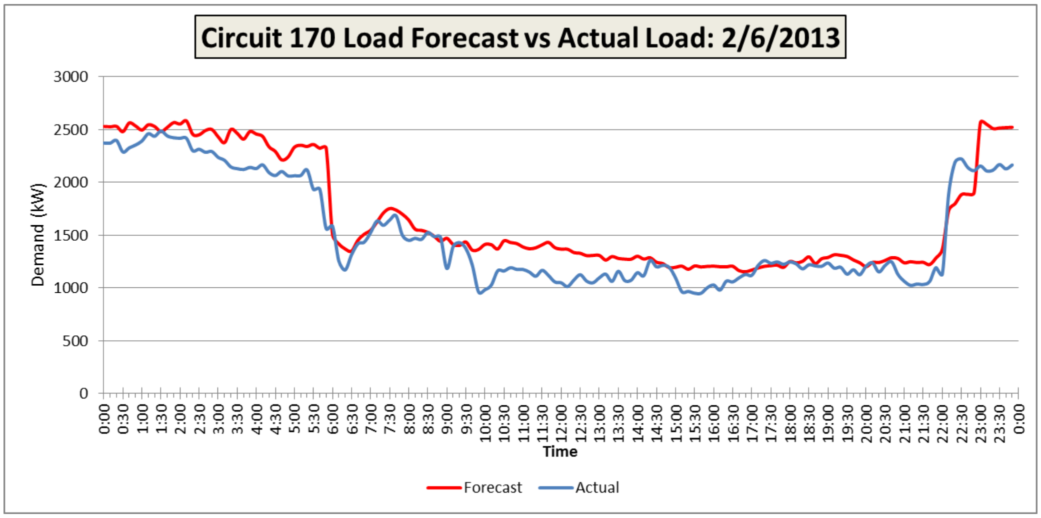


Figure 38: Example Load Forecast

Microgrid Pricing - The Pricing Module is used to calculate the wholesale price of electricity ($/MWh) for electricity delivered to customers within the Microgrid. The wholesale price is dependent on the operation of Microgrid Resources in along with the transmission grid. If the Microgrid resources are non-operational, the wholesale price is equal to the Locational Marginal Price at the Borrego node. This LMP nodal price is obtained through an interface with CAISO's Nodal LMP system (referred to OASIS). If the Microgrid resources are operational, the wholesale price is calculated by calculating an average weighted price of energy obtained from the grid at the LMP nodal price and the price of energy produced by the operating Microgrid Resources.

The wholesale price consists of the following components:

- DG #1 Price – Price associated with the operation of Distributed Generator #1
- DG #2 Price – Price associated with the operation of Distributed Generator #2
- Grid Price - The Grid Price is equal to the CAISO DAM LMP price for the Borrego Node
- SES Price – Price associated with the charge/discharge operation of the Substation Energy Storage unit

CAISO wholesale prices were downloaded from the CAISO OASIS website on a daily basis. The data was available in a comma separated values file and was transferred to the Microgrid Visualizer. An internal script running on the Microgrid Visualizer picked up the CAISO price and transferred the values to the Pricing Module once every 24-hours.

The base formula to calculate the Total Weighted Average Price ($Microgrid\ Price_{\$/MWh}$) is:

$$\frac{\left(MW_{DG1} * \frac{\$}{MWH_{DG1}}\right) + \left(MW_{DG2} * \frac{\$}{MWH_{DG2}}\right) + \left(MW_{SES} * \frac{\$}{MWH_{SES}}\right) + \left(MW_{GRID} * \frac{\$}{MWH_{GRID}}\right)}{MW_{DG1} + MW_{DG2} + MW_{SES} + MW_{GRID}}$$

An exception to this calculation occurs when the SES is in the charging mode. The Total Weighted Average Price ($Microgrid\ Price_{\$/MWh}$) during the charging interval is calculated by excluding the SES Aggregate Price component. The value of electricity in the SES unit is accounted for by using the LMP price at the time of the charging and the quantity of electricity added to the SES while charging. Prior to discharging the SES unit, the average cost of electricity for all the energy stored in the unit is calculated. This is used as the basis of the price of energy from the SES unit during the entire discharge cycle.

Table 10 presents the total weighted average price calculation for a simulation of Microgrid resources running on January 15, 2013. DG# 1 and DG# 2 were operating for two hours between 11:00 AM to 1:00 PM, while the SES was discharging between 10:00 AM to 12:00 noon. The CAISO wholesale price for that particular day is shown in the third column. The Table shows that at time periods when the DG unit or the SES is not operating, the Microgrid price is equal to the CAISO Price. During time periods when the DG units and SES were operated the Microgrid price is calculated and the associated Microgrid Price is calculated.

Table 10: Microgrid Price Calculation – 01/15/2013 Simulation

		CAISO Price	DG 1				DG 2				SES						Grid			Microgrid Price
Date	Time	LMP ($/MWh)	Fuel Flow (Gallons/Min)	Gallons/Hour	kW	Hourly Cost $/MWh	Fuel Flow (Gallons/Min)	Gallons /Hour	kW	Hourly Cost $/MWh	kW (ES Charge Rate)	Incremental Dollars	$ Balance	SOC	Available Capacity MWh	$ Balance $/MWh	kW	Hourly Cost $/MWh		Total Weighted Price $/MWh
											1									
1/14/2013	0:00	$ 37.63	0.10	6.0	0.0	0.00	0.2	12.00	0.0	0.00	-25	$ 0.94	$ 50.94	94%	1.410	36.13	3719	$ 37.63		$ 37.63
1/14/2013	1:00	$ 35.80	0.10	6.0	0.0	0.00	0.2	12.00	0.0	0.00	-7.8	$ 0.28	$ 51.22	94%	1.410	36.33	3546	$ 35.80		$ 35.80
1/14/2013	2:00	$ 36.23	0.10	6.0	0.0	0.00	0.2	12.00	0.0	0.00	-14.5	$ 0.53	$ 51.75	94%	1.410	36.70	3460	$ 36.23		$ 36.23
1/14/2013	3:00	$ 35.73	0.10	6.0	0.0	0.00	0.2	12.00	0.0	0.00	-3.7	$ 0.13	$ 51.88	94%	1.410	36.79	3460	$ 35.73		$ 35.73
1/14/2013	4:00	$ 36.93	0.10	6.0	0.0	0.00	0.2	12.00	0.0	0.00	-14.7	$ 0.54	$ 52.42	93%	1.395	37.58	3546	$ 36.93		$ 36.93
1/14/2013	5:00	$ 44.46	0.10	6.0	0.0	0.00	0.2	12.00	0.0	0.00	-7.8	$ 0.35	$ 52.77	94%	1.410	37.42	3287	$ 44.46		$ 44.46
1/14/2013	6:00	$ 69.73	0.10	6.0	0.0	0.00	0.2	12.00	0.0	0.00	-10.0	$ 0.70	$ 53.46	94%	1.410	37.92	3027	$ 69.73		$ 69.73
1/14/2013	7:00	$ 74.37	0.10	6.0	0.0	0.00	0.2	12.00	0.0	0.00	-7.3	$ 0.55	$ 54.01	94%	1.410	38.31	3373	$ 74.37		$ 74.37
1/14/2013	8:00	$ 76.82	0.10	6.0	0.0	0.00	0.2	12.00	0.0	0.00	-21.0	$ 1.61	$ 55.62	94%	1.410	39.45	3027	$ 76.82		$ 76.82
1/14/2013	9:00	$ 74.59	0.10	6.0	0.0	0.00	0.2	12.00	0.0	0.00	-15.2	$ 1.13	$ 56.75	94%	1.410	40.25	2681	$ 74.59		$ 74.59
1/14/2013	10:00	$ 72.62	0.10	6.0	0.0	0.00	0.2	12.00	0.0	0.00	104.3	$ (4.20)	$ 52.56	94%	1.410	40.25	2076	$ 72.62		$ 71.07
1/14/2013	11:00	$ 38.87	1.00	60.0	823.0	293.80	1.1	66.00	847.0	314.03	293.8	$ (11.83)	$ 40.73	83%	1.245	40.25	173	$ 38.87		$ 246.31
1/14/2013	12:00	$ 36.09	1.00	60.0	787.0	307.24	1.0	60.00	798.0	303.01	-13.0	$ 0.47	$ 41.20	65%	0.975	42.25	0	$ 36.09		$ 305.11
1/14/2013	13:00	$ 35.56	0.10	6.0	0.0	0.00	1.8	108.00	0.0	0.00	-75.0	$ 2.67	$ 43.86	73%	1.095	40.06	1643	$ 35.56		$ 35.56
1/14/2013	14:00	$ 35.90	0.10	6.0	0.0	0.00	1.8	108.00	0.0	0.00	-150.0	$ 5.38	$ 49.25	76%	1.140	43.20	1557	$ 35.90		$ 35.90
1/14/2013	15:00	$ 38.52	0.10	6.0	0.0	0.00	1.8	108.00	0.0	0.00	-50.0	$ 1.93	$ 51.17	73%	1.095	46.73	1297	$ 38.52		$ 38.52
1/14/2013	16:00	$ 40.97	0.10	6.0	0.0	0.00	1.8	108.00	0.0	0.00	-99.0	$ 4.06	$ 55.23	73%	1.095	50.44	1297	$ 40.97		$ 40.97
1/14/2013	17:00	$ 53.90	0.10	6.0	0.0	0.00	1.8	108.00	0.0	0.00	-75.0	$ 4.04	$ 59.27	77%	1.155	51.32	1730	$ 53.90		$ 53.90
1/14/2013	18:00	$ 59.83	0.10	6.0	0.0	0.00	1.8	108.00	0.0	0.00	-75.0	$ 4.49	$ 63.76	80%	1.200	53.13	2076	$ 59.83		$ 59.83
1/14/2013	19:00	$ 53.22	0.10	6.0	0.0	0.00	1.8	108.00	0.0	0.00	-75.0	$ 3.99	$ 67.75	83%	1.245	54.42	2335	$ 53.22		$ 53.22
1/14/2013	20:00	$ 51.13	0.10	6.0	0.0	0.00	1.8	108.00	0.0	0.00	-75.0	$ 3.83	$ 71.59	87%	1.305	54.86	2681	$ 51.13		$ 51.13
1/14/2013	21:00	$ 47.78	0.10	6.0	0.0	0.00	1.8	108.00	0.0	0.00	-74.0	$ 3.54	$ 75.12	90%	1.350	55.65	2854	$ 47.78		$ 47.78
1/14/2013	22:00	$ 44.36	0.10	6.0	0.0	0.00	1.8	108.00	0.0	0.00	-41.7	$ 1.85	$ 76.97	92%	1.380	55.78	2768	$ 44.36		$ 44.36
1/14/2013	23:00	$ 39.92	0.10	6.0	0.0	0.00	1.8	108.00	0.0	0.00	-17.3	$ 0.69	$ 77.66	62%	0.930	83.51	3806	$ 39.92		$ 39.92

An example wholesale price as posted on the CAISO website for 01/15/2013 is presented in Figure 39 on the following page.

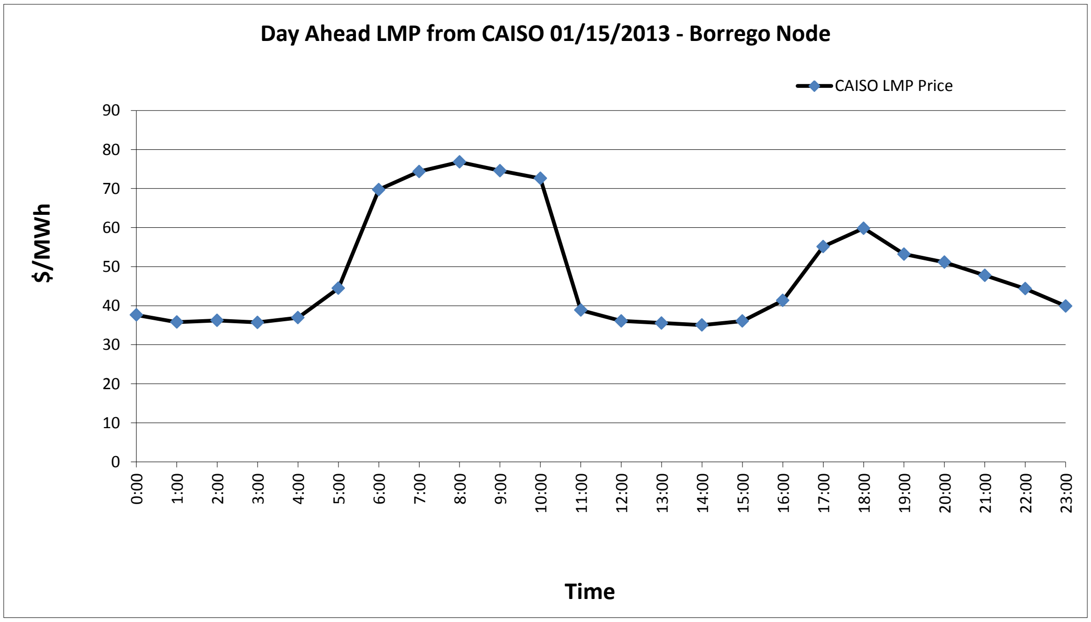


Figure 39: Day Ahead LMP Price from CAISO 01/15/2013 – Borrego Node

An example of the calculation is presented below for the system operations between 11:00 AM and 12:00 noon where DG #1 was running at 823 kW and DG #2 was running at 847 kW. The calculation used for DG1 and DG2 prices is as follows:

- $DG\ 1\ Price_{\$/MWh} = \left(DG\ 1 Fuel\ Flow_{\frac{Gallons}{Hour}} \times Fuel\ Cost_{\frac{\$}{Gallon}}\right) \div (MW_{DG1})$
- $DG\ 2\ Price_{\$/MWh} = \left(DG\ 2\ Fuel\ Flow_{\frac{Gallons}{Hour}} \times Fuel\ Cost_{\frac{\$}{Gallon}}\right) \div (MW_{DG2})$

Using the formula, the DG #1 Price is $293.80/MWh and the DG# 2 Price is $314.03/MWh.

The SES unit was discharging at a rate of 293.8 kW at a calculated value of $40.25/MWh. An intermediate value for the energy stored in the battery, $Balance to manage the calculation of the ongoing value of electricity in the SES unit. The state of charge is used to estimate the total quantity of energy (kWh) available in the battery. During a charge cycle, the incremental value is added to the $Balance. The value of the energy associated with removing energy from the SES is calculated by diving the $Balance with the capacity of the battery just prior to the discharge cycle.

The components of the Total Weighted Average price associated with the operation of the Microgrid resources between during the hour of 11:00 AM is:

- DG1 (823 kW x 293.80 $/MWh) = $241.79/Hour
- DG2 (847 kW x 314.03 $/MWh) = $265.98/Hour
- SES (293.8 kW x 40.25 $/MWh) = $11.82/Hour
- Grid (173 kW x 38.87 $/MWh) = $6.72/Hour
- Total Energy (kW) = 2,136.8

The Total Weighted Average Price = 246.31 $/MWh

The Microgrid Price (Total Weighted Average Price) is presented graphically in Figure 40.

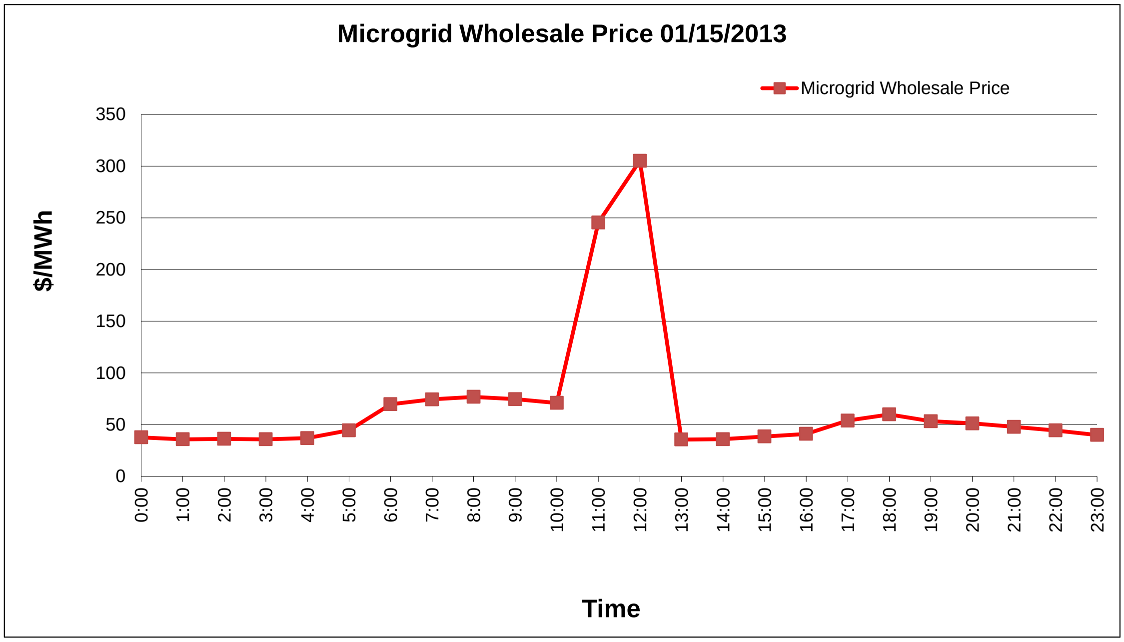


Figure 40: Microgrid Wholesale Price Simulation 01/15/2013

As seen in Figure 40, the Microgrid Wholesale price is different than the CAISO Wholesale price between 10:00 AM and 1:00 PM when the Microgrid Resources (DG #1, DG #2 and SES) were in operation.

This Total Weighted Average price was sent to the Price Driven Load Management system which translates the wholesale price to the retail price for present to the customers and their HAN systems. After a detailed quantitative analysis of historical CAISO wholesale prices, five pricing levels were developed to translate the Microgrid wholesale price to the customer retail price. The pricing model was developed to target a maximum of eight hours per week of prices that would trigger the HAN devices to alter operation of their connected equipment. The modeled distribution of pricing levels is 4 hours at Level 3, 2 hours at Level 4, and 2 hours at Level 5. Table 11 on the following page presents pricing level methodology used to translate the wholesale price to retail price.

Table 11: Pricing Levels

Pricing Level	Wholesale Price Range ($/MWh)	Retail Price ($/KWh)	Hours of Occurrence per Week	Frequency of Occurrence
Level 1	$00.00 to 29.00	$0.10	26	15.2%
Level 2	$29.01 to 59.49	$0.25	134	80.0%
Level 3	$59.50 to 66.99	$0.37	4	2.4%
Level 4	$67.00 to 74.99	$0.45	2	1.2%
Level 5	>$75.00	$0.60	2	1.2%

The translation methodology is based on the consolidation of thresholds where a pricing signal is a limit that if exceeded will trigger the Pricing Level. For example, a wholesale price of $70.00/MWh will trigger Levels 1 through 4.

These pricing levels are designed such that the HAN devices will respond to price fluctuations based on the thresholds set by the customer through the PDLM Customer Portal. Default settings were programmed into the HAN devices at the time of installation. These programs were developed to respond at Level 3 and above with the device settings as follows:

- Level 3: Plug Load Controllers (PLC) activated
- Level 4: Programmable Communicating Thermostats (PCT) operate with a 2 ^{o}F offset in cooling mode and PLCs are activated
- Level 5: PCT operates with a 4 ^{o}F offset in cooling mode and PLCs are activated

Figure 41 on the following page presents an example of the how the hourly prices based on the Microgrid wholesale price was used to trigger the defined event Levels in the PDLM system. Note that the pricing model was implemented as a simulation for the purposes of this demonstration and that the customer bills were not affected by prices being passed to the devices.

In this example, Level 5 events would be executed at 8:00 AM, 11:00 AM and 12:00 noon that would adjust the PCT temperature by 4 ^{o}F and switch off devices on the PLC. Level 4 events would be executed between 6:00 to 12:00 hours that adjusted the PCT temperature by 2 ^{o}F and switch off devices on the PLC. In addition, Level 3 events would be executed between 6:00 AM to 12:00 noon and at 6:00 PM, when the devices on the PLCs would be switched off.

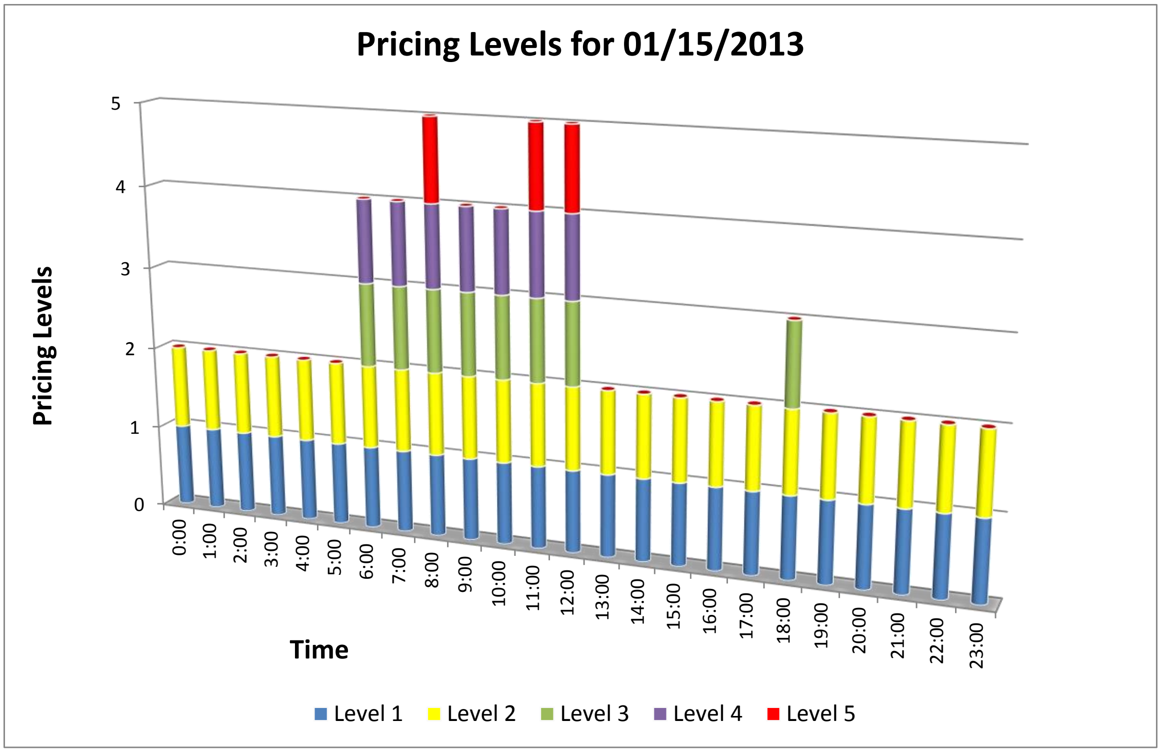


Figure 41: Pricing Levels Simulation 01/15/2013

Peak Shaving Optimization -This demonstration addressed one of the main objectives of the demonstration project of circuit peak load reduction of 15% or more. The ability to achieve this reduction has many challenges due to the timing and duration of the peak load. The issues addressed in order to achieve the circuit peak load reduction are as follows:

- Night Time Peak on Circuit: The peak load occurs on the circuit between 11:00 PM and 6:00 AM due to the operation of pumps operated by the water district and several agricultural customers on the circuit. These customers are on a time of use tariff that has significantly lower demand and energy charges during this weekday time period.
- Peak Shave Requirements: Figure 42 on the following page presents the target for the peak shave operation with an import limit of 2,200 kW at the Microgrid Circuit Breaker. This represents a peak load reduction of 550 kW and requires a total of 2,255 kWh over a period of 6 hours and 40 minutes.

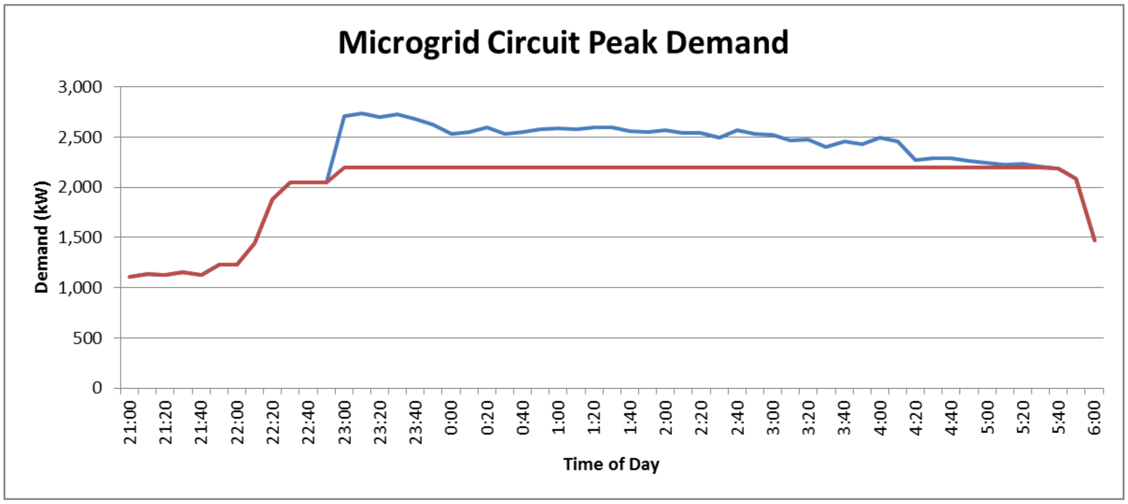


Figure 42: Target Peak Shave Requirements

- DG Operating Permits: The operating permits for the DG units stipulate limitations on the hours of operation permitted for each unit based on a maximum of 8 hours per day, a maximum of 40 hours per week, and a maximum of 200 hours per year. In addition, the generators can only be operated between the hours of 7:00 AM and 7:00 PM with a provision of operation between the hours of 7:00 PM and 1:00 AM twice a month.
- SES Capacity: The SES unit has a maximum operating charge and discharge rate of 500 kW and has a nominal energy storage capacity of 1,500 kWh.
- DG Minimum Operating Capacity: The DG units must operate at a minimum of 500 kW.

Based on the objectives and the stated constraints the only way to achieve the peak shave goals is to operate the DG units and the SES in a sequence where the SES will operate in load following in both discharge and charge modes and the DG unit is operated to its maximum potential until 1:00 AM. Figure 43 on the following page presents the conceptual plan for sequence of operation. The sequence consists of three major steps phases as follows:

- Step 1 (SES stand alone in load following): Prior to the peak shaving operation, the SES is at a mid-level state of charge. When the load initially reaches the target import threshold limit, the SES operates in load following mode until the capacity required by the SES unit approaches 500 kW. At the same time, the DG unit is started and warmed up in preparation for synchronization to the circuit.
- Step 2 (DG constant output and SES Charging in Load Following mode): As the load that is in excess of the import set point exceeds 500 kW, the DG unit is synchronized with the circuit and loaded to its constant output set point. The DG output is set so that it is greater than the required load forcing the SES unit to switch to charge mode while maintaining the import control limit. This step is maintained until the DG cut off time of 1:00 AM while the SES unit charged to a high state of charge.
- Step 3 (SES stand alone in load following): After 1:00 AM, the SES continues to load follow. If the load drops below the import set point, the SES unit will then switch back to

charging and stop when directed by the Microgrid Operator or it reaches the maximum SOC threshold. If the load remains above the import set point, the SES unit will then continue discharging and stop when directed by the Microgrid Operator or it reaches the minimum SOC threshold.

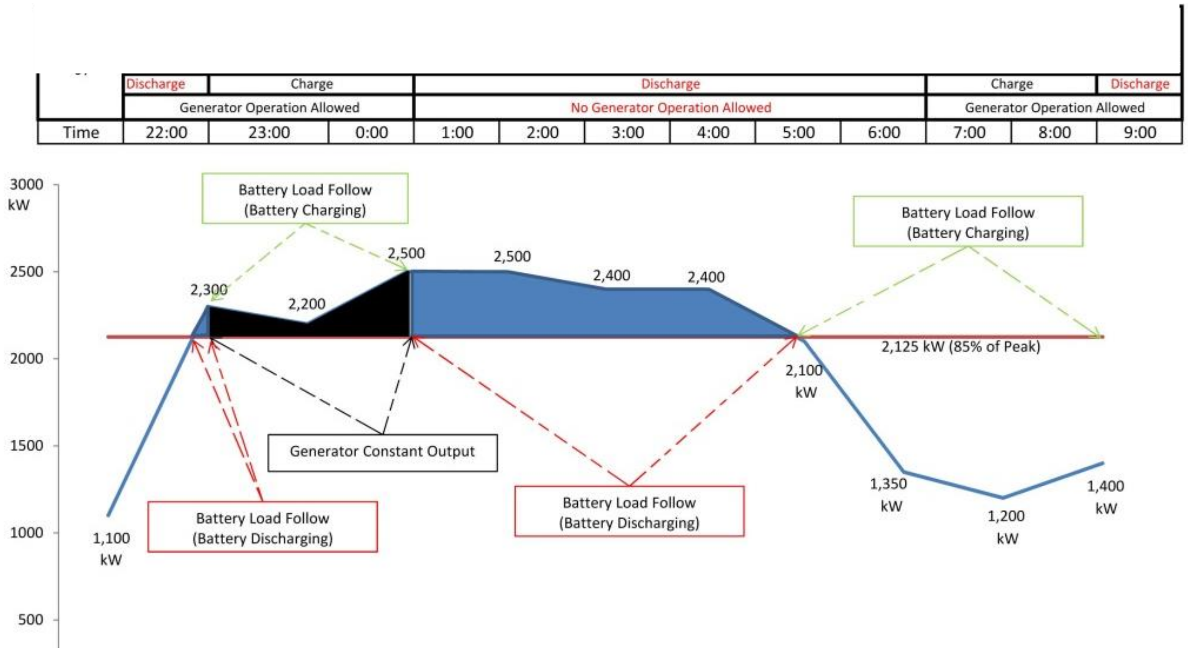


Figure 43: Conceptual Plan for Peak Shaving Optimization

Figure 44 on the following page presents the three graphs for the peak shave demonstration conducted on the night of January 24, 2013. The load forecast was used for calculating the operating set points of the DG and SES that would support night time peak shave of the combined resources. The actual load on the circuit was closely monitored to ensure that the resources were able to support the peak shave demonstration. Figure 44 shows the load forecast that was used as the basis for the plan and the actual load that was encountered during the demonstration.

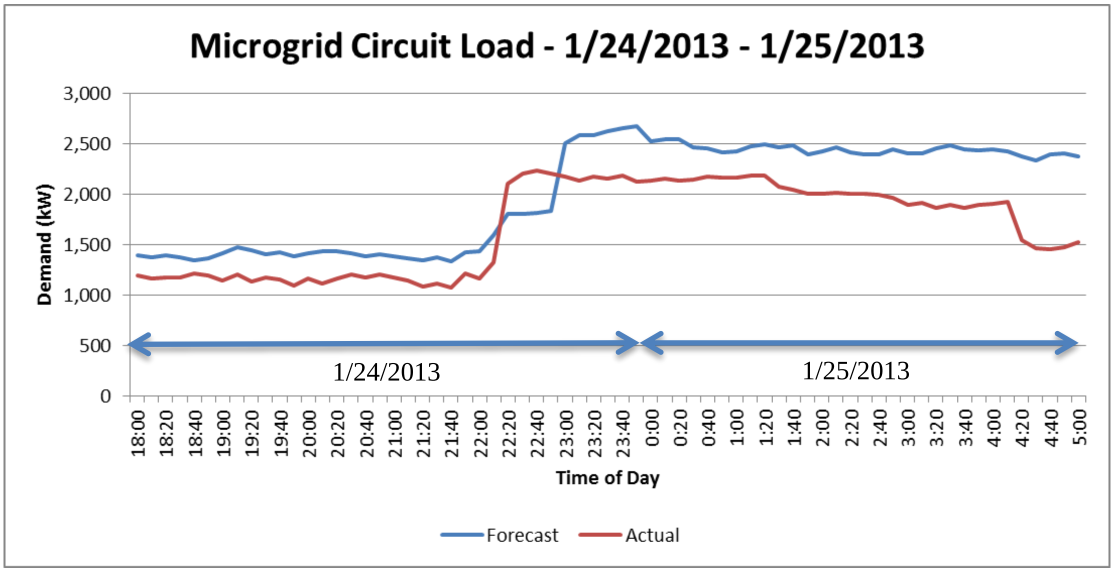
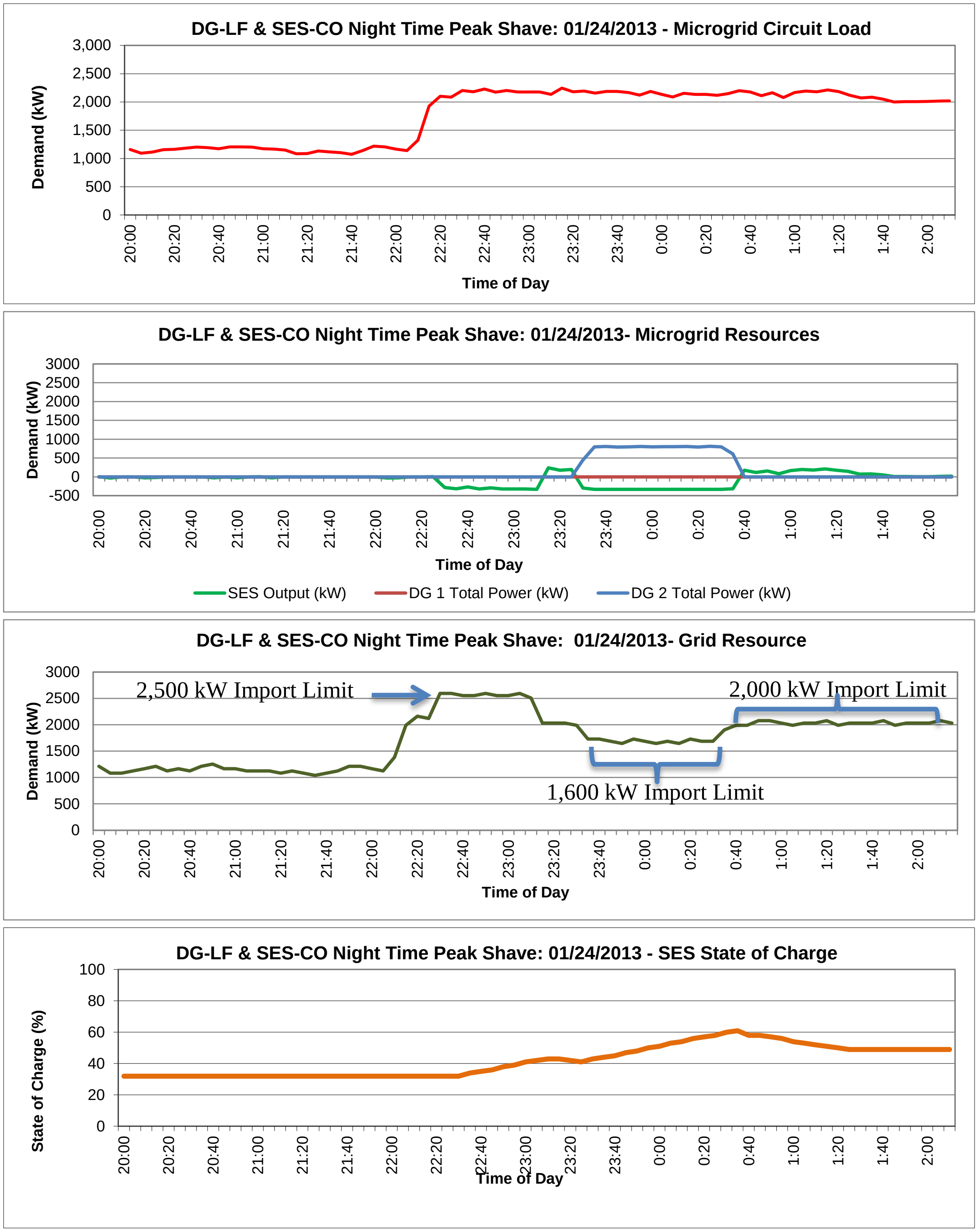


Figure 44: Microgrid Circuit Load for Peak Shave Demonstration

The plan was to initiate the peak shaving to a limit of 2,500 kW at approximately 11:00 PM. As the Microgrid Operator was monitoring the load, it started to increase rapidly at approximately 10:15 PM. The decision was made to initiate the peak shave operations at that time and the SES unit was placed in load following. Since the load on the circuit was less than 2,500 kW, the SES unit went into charge mode to increase the load to the 2,500 kW set point. Figure 44 shows that the actual load of the Microgrid Circuit did not reach 2,500 kW and peaked at only 2,200 kW. Since the ability to operate the DG units at night time was extremely limited, it was decided to continue the demonstration as planned but at a lower import threshold of 1,600 kW. At that point, DG #2 was set to operate in load following and the SES was set to charging at 250 kW. The Microgrid operated in this mode for approximately an hour and half. The DG units could only be operated until 1:00 AM due the regulatory restrictions. Hence, the generator was ramped down to zero at 12:45 AM so that engine could complete its entire shut down process prior to 1:00 AM. At that time, the SES was charged to a 60% state of charge and was placed in peak shave mode with a 2,000 kW set point until approximately 2:00 AM. This sequence is presented in Figure 45 on the following page.



Note: LF=Load Following; CO=Constant Output

Figure 45: DG and SES Night Time Peak Shave Operation

6 Deployment Scenarios

A deployment plan was developed for the optimized Microgrid solutions that were consistent with the cost/benefit analysis of Task 5.1 report. The approach used was to extrapolate a large-scale deployment of selected advanced distribution control (Microgrid) / DER strategies that meet the requirements of the CBA of Task 5.1.

As stated in the Task 5.1 report, there are five identified solutions structured to enable maximum benefits at specific load nodes on the SDG&E distribution network. The identified solutions are:

F. Large Microgrid (10 MW)
G. Medium Microgrid (4 MW)
H. Small Microgrid (1 MW)
I. Distributed Energy Resource (DER) solution (0.3 MW)
J. Residential solution (0.004 MW)

The benefits are derived from addressing issues specific to commercial and industrial (C&I) consumer needs, communities challenged by high penetration of solar PV (HPV), weak points (WP) in the network, end of circuit (EOC) challenges, and other (O) special needs (e.g. sports venues, data centers, and hospitals). The benefits from addressing these challenges accrue to certain beneficiaries:

- Consumer (direct benefit to single consumers)
- System (direct improvement in operations, system efficiency, and capital efficiency)
- Societal (broadly applied benefits to many consumers)

This CBA resulted in 28 identified solutions in two phases as presented in Table 12 and Table 13 respectively. The 28 identified solutions include:

- 10 MW Microgrid: Quantity = 2
- 1 MW Microgrid: Quantity = 8
- DER Solutions (300 kW): Quantity = 18

The deployment plan covers eight years in two Phases:

- Phase 1: years 0 through 2; 10 identified solutions, all DER solutions
- Phase 2: years 3 through 7; 18 identified solutions; 2 large Microgrids, 8 small Microgrids, and 8 DER solutions

Table 12: Phase 1 Identified Solutions at Key Load Nodes

Zip Code	Estimated Demand (MW)	Nodal Strategic Priority Score	Benefit Characteristic Solution	Viable Solution Fit	MW
91932	11.36	5.70	Weak Point	DER (D)	0.3
91933	11.36	5.70	Weak Point	DER (D)	0.3
91942	13.20	4.55	Weak Point	DER (D)	0.3
91942	13.18	4.55	Weak Point	DER (D)	0.3
92071	11.18	3.80	Weak Point	DER (D)	0.3
92121	14.00	4.55	End of Circuit	DER (D)	0.3
92122	11.78	6.45	Weak Point	DER (D)	0.3
92122	11.78	4.55	Weak Point	DER (D)	0.3
92130	14.50	4.55	Weak Point	DER (D)	0.3
92086	2.51	5.70	End of Circuit	DER (D)	0.3

Table 13: Phase 2 Additional Identified Solutions at Key Load Nodes

Zip Code	Estimated Demand (MW)	Nodal Strategic Priority Score	Benefit Characteristic Solution	Viable Solution Fit	MW
92019	13.20	1.90	Weak Point	DER (D)	0.3
92026	12.59	1.90	Weak Point	DER (D)	0.3
92027	12.97	3.80	High Penetration PV	Small Microgrid (C)	1.0
92029	11.34	3.80	High Penetration PV	Small Microgrid (C)	1.0
92040	15.88	1.90	High Penetration PV	Small Microgrid (C)	1.0
92064	13.38	5.40	High Penetration PV	Small Microgrid (C)	1.0
92069	15.69	1.90	Weak Point	DER (D)	0.3
92111	13.65	1.90	Weak Point	DER (D)	0.3
92121	14.00	4.55	Commercial & Industrial	Large Microgrid (A)	10.0
92121	14.00	1.90	Weak Point	DER (D)	0.3
92123	27.10	5.30	Commercial & Industrial	Large Microgrid (A)	10.0
92126	13.34	1.90	Weak Point	DER (D)	0.3
92126	13.34	1.90	High Penetration PV	Small Microgrid (C)	1.0
92128	11.96	1.90	Weak Point	DER (D)	0.3
92128	11.25	5.55	High Penetration PV	Small Microgrid (C)	1.0
92130	14.50	4.55	High Penetration PV	Small Microgrid (C)	1.0
92131	13.35	3.80	High Penetration PV	Small Microgrid (C)	1.0
92131	13.35	1.80	Weak Point	DER (D)	0.3

CBA for SDG&E deployment - The cost/benefit analysis result for the entire 150 load nodes is presented above in Section 5. In contrast, the Phase 1 and Phase 2 CBA results are presented here.

Table 14: Phase1 and 2 Cost/Benefit Analysis

Benefits	**Annual Benefits**	**20-Year Present Value**
Consumer Benefits	$4,824,972.75	
System Benefits	14,557,285	
Societal Benefits	372,702.34	
	$19,754,960	$152,570,785
Capital Cost	**Capital Cost**	
C&I	$32,978,087	
HPV	14,656,357	
WP	5,957,654	
EOC	744,707	
Other	-0-	
	$54,336,804	
Utility Equity Portion of Capital Expense	50.0%	
Utility Equity Spend	*$27,168,402*	$19,337,194
First Year O&M Cost	**First Year O&M Cost**	
C&I	$7,996,000	
HPV	2,012,569	
WP	5,440,000	
EOC	680,000	
Other	$-	
	$16,128,569	$124,563,568
First Year Federal ITC	**First Year Federal ITC**	
C&I	$3,241,832	
HPV	2,012,569	
WP	1,527,518	
EOC	190,940	
Other	$-	
	$6,972,859	$4,962,954
NPV Benefit w/o Federal ITC		$8,670,022
NPV Benefit w/ Federal ITC		$13,632,976
Number of Solutions		28
Capital Cost		$54,336,804

Thus, Phase 1 and 2 (together) represent a total net present value (NPV) benefit of nearly $9 million after all capital costs and O&M costs are covered.

The 28 identified Solutions can be found in 22 load nodes. Several load nodes required more than one identified Solution to deliver the maximum benefits. Table 14 presents these findings.

Further review shows that a subset of the 28 identified Solutions, represented as Phase 1, yields a higher benefit to cost ratio, as expected. Table 15 shows this subset, Phase 1.

Table 15: Phase1 Cost Benefit Analyses

Benefits	**Annual Benefits**	**20-Year Present Value**
Consumer Benefits	-0-	
System Benefits	$5,093,646	
Societal Benefits	-0-	
	$5,093,646	$39,339,061
Capital Cost	**Capital Cost**	
C&I	-0-	
HPV	-0-	
WP	$2,978,827	
EOC	744,707	
Other	-0-	
	$3,723,534	
Utility Equity Portion of Capital Expense	50.0%	
Utility Equity Spend	*$1,861,767*	$1,325,118
First Year O&M Cost	**First Year O&M Cost**	
C&I	-0-	
HPV	-0-	
WP	$2,720,000	
EOC	680,000	
Other	-0-	
	$3,400,000	$26,258,754
First Year Federal ITC	**First Year Federal ITC**	
C&I	-0-	
HPV	-0-	
WP	$763,759	
EOC	190,940	
Other	-0-	
	$954,699	$679,510
NPV Benefit w/o Federal ITC		$11,755,189
NPV Benefit w/ Federal ITC		$12,434,699
Number of Solutions		10
Capital Cost		$3,723,534

Thus, Phase 1 represents a total net present value benefit of nearly $12 million after all capital costs and O&M costs are covered. These 10 identified Solutions can be found in seven load nodes.

Lessons from the Results

- As expected, the smaller, higher priority set of solutions represented in Phase 1 yielded a higher total net present value benefit, based on a smaller cost for these 10 solutions. It is interesting to note that this highest value set consists of two EOC and eight WP characteristics solved with DER solutions.
- In the subsequent 18 solutions that represent the balance of Phase 2, there is a wide variety of solutions employed. The variety of solutions gives SDG&E the opportunity to compare performance in solving the characteristic issues being addressed. This set also represents the next highest benefit cost ratios of the high priority load nodes.
- Since the Phase 1 NPV Benefits were $12 million and the Phase 2 NPV Benefits were $9 million, one could say that the additional 18 solutions reduced the NPV Benefits by $3 million. This trend would suggest that seeking more than 28 solutions at the 22 load nodes in the SDG&E territory would not likely generate sufficient benefits to justify the capital and O&M costs.
- The largest cost factors in the cost/benefit analysis that affected the benefit to cost ratio the most were found in the O&M costs: natural gas fuel costs and finance payments. These two costs create the largest sensitivity to the benefit cost ratio, and hence, the cost/benefit analysis.

Financials – Technology Implementation - With the staged deployment as outlined in Section 4, the Phase 1 and 2 financial trend is shown in Figure 46. The proposed deployment plan becomes cash positive in the sixth year. The graph clearly shows the major effect of the operations and maintenance (O&M) costs, where fuel costs and loan payment constitute 80% to 83% of the O&M expense. Thus, driving the cost of fuel and loan payments down will improve the business case.

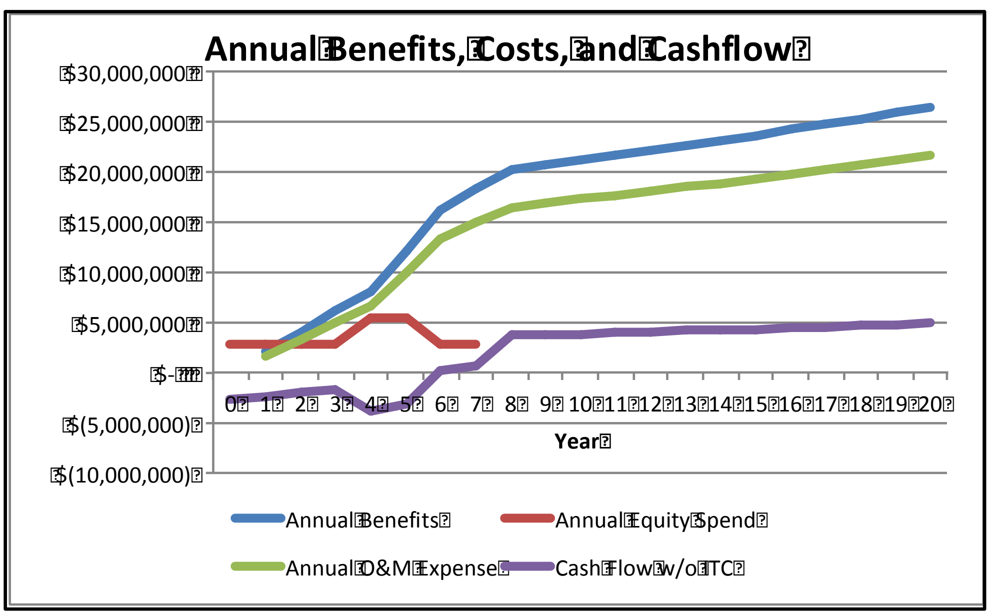


Figure 46: Cash Flow for the Proposed Deployment Plan

7 Lessons Learned and Key Findings

Lessons Learned

The Microgrid demonstration proved to be a challenging project due to the complexity of integrating new systems to the distribution network that could impact customers, reliance on other projects for integration, the use of newly emerging technologies and systems, and environmental requirements.

The team first identified the complexities during the use case development phase of the project. The key stakeholders identified specific constraints with the existing systems and utility processes which drove some key elements of the system architecture for the demonstration. The use case process also demonstrated that Microgrids impact nearly all the departments within the utility. It became clear that the approach that would be implemented for the demonstration would be a first step toward the ability to integrate Microgrids but a more comprehensive enterprise strategy would need to be developed if Microgrids were to be employed as a common resource in the service territory.

The Microgrid project leveraged two existing diesel generators for the project. The team initially assumed that this resource would be the most straight forward resource for integration and operation. Two major issues had to be addressed for the generators 1) the existing controls were inadequate for the project, and 2) the environmental requirements were more onerous than expected. The control system had to be upgraded to support the planned modes of operation and remote control of the units. In addition, the control interface had to include a method for the Distribution Operators to have a level of control over the units in terms of paralleling to the grid in a safe manner and disconnecting the generator in the case a fault on the circuit. To address the emission requirements, the units were retrofit with a state-of-the-art emissions system that met the Tier 4 emissions level required for the maximum annual hours of operation. Even while meeting the most stringent standard for emissions, the generators had significant restrictions on annual (200 hours/year), monthly, weekly and daily hours of operation, as well as time of day restrictions. An additional constraint was associated with the noise coming from the generators. To mitigate the noise issues, baffles were installed on the generators air intake, ventilation louvers and exhaust systems, a “sound” wall was constructed on one side of the Microgrid Yard that was facing the closest customer (~ 1,000 feet away), and advance customer notice of operation was required.

For this project, the storage component proved to be quite challenging. Part of the challenge was that the Microgrid storage unit was one of the first energy storage units purchased by the utility. The Project team had to develop a specification and an RFP for the procurement. During the procurement process, it was learned that the storage systems available at the time were basically custom units and that few vendors could provide a turnkey solution without teaming with another company. Vendors were either able to provide the storage or the power electronics but not both. The procurement process for the Microgrid project took much longer than expected. The RFP released at the early stages of the project resulted in the selection of a flow battery technology.

A contract was never signed as the vendor had some difficulties in scaling their solution while maintaining their efficiency. SDG&E worked with the vendor with support from EPRI to try to resolve the performance issues but ultimately the procurement was canceled. A second RFP was issued and this time a lithium ion technology was selected. The implementation schedule for the selected storage unit was approximately a year. Due to the desert climate of the Microgrid project, the vendor had to add air conditioning to the storage containers and the PCS to maintain the appropriate operating temperatures in the storage system enclosures. This unexpectedly proved to be an issue with the reliability of the units. Failures of the air conditioning units caused the batteries and the PCS to shut down. The controls protected the system so the equipment was not damaged when to the high temperature events occurred. The cooling issue was addressed and eventually resolved during the course of the demonstration.

The implementation of FLISR relied on installing a new distribution management system being deployed by the utility. The ability to program and simulate the FLISR operations on the Microgrid Circuit was delayed until the end of the demonstration due to the schedule and requirements of the larger Advanced Distribution Management System project. However, the Microgrid Circuit was the circuit used to develop the test cases and validate FLISR operations for the new distribution management system.

The PDLM system integration and deployment was expected to be challenging at the beginning of the project and this proved to be the case as the project was executed. The use case results from the beginning of the project were used to develop an RFP for the system. A vendor that had formed a team to provide a turnkey solution was selected. The vendor had a base software solution for demand response that was modified to meet the pricing functional requirements for the Microgrid project. At first, this appeared to be a benefit to meeting the project schedule; however the schedule was a challenge for the project. It should be noted that the PDLM portion of the demonstration was co-funded by the California Energy Commission contract that had a shorter period of performance than the DOE funded portion of the demonstration. The implementation of the PDLM software required a security validation process before it could be approved to be operated along with the "production" systems operated by the utility. This process had a major impact on the schedule.

Another challenge to the PDLM implementation was the recruitment of customers. Many customer outreach and recruitment events were held in the community to entice residential customers to have the HAN systems installed in their homes and participate in non-tariff based demand response events over the course of a one year period. The target for the number of participants was 125; however a total of 65 were enrolled and participated. By the time the system was installed and accepted for operation, the demonstration project schedule was near the end and many of the demand response events had to be conducted during a non-summer time period which significantly reduced the real demand response impact of weather based loads (i.e. air conditioning).

A significant effort was placed on the development of a Microgrid Controller for the demonstration project. The challenge for the Microgrid Controller was that there was not an existing product in the market that could easily be acquired and modified to meet the needs of the project. A decision was made to work with the vendor selected for the new Distribution Management System to leverage this work to provide a Microgrid Controller. While this initially appeared to be a benefit to the project it became clear that the timeline for product development and controller objectives by the vendor did not align well with the demonstration project. Furthermore, the security testing requirements to place the controller into the utility's "production" environment pushed the delivery schedule out further. It was finally decided to develop a project-specific application to provide a consolidated view of the Microgrid Resources referred to as the Microgrid Visualizer. The Microgrid Visualizer facilitated the planned Microgrid demonstrations by providing a method to easily operate the systems from a single screen, schedule equipment, monitor operations, and collect data. The Microgrid Visualizer was successfully used to support the demonstrations, including islanding operations, but is not a standalone and fully-automated control system.

Finally, another issue that had to be addressed for the demonstration project was the load profile of the Microgrid Circuit. The load profile is very unconventional where the peak load occurs at night when the water district and agricultural customers operate pumps for an extended period of time. From a technical perspective this is not an issue for a Microgrid to appropriately meet its peak load, economic, and reliability objectives. However, the environmental and other constraints identified above related to the allowed generator time of use, prevented the generators from fully addressing the peak load management objectives of the project. In order to address these constraints, demonstrations were designed and conducted to address the peak load management through a sequence of operation using a combination of the DG units and the storage system. For example, because the generators could not operate after 1:00 AM, any demonstrations that occurred after that time had to rely on the storage system only.

Key Findings

The aspects of the project considered to be unique and to potentially advance the knowledgebase of Microgrids were:

- **Development of an architecture and operational processes for utility-based Microgrids**
  The Microgrid demonstration provided key lessons about the architecture that was suitable for this Microgrid demonstration. However, the demonstration did not produce an architecture that is easily scalable for deployment for the entire service territory. A scaled up deployment in the service territory will require a comprehensive enterprise strategy and additional automation capabilities through the distribution management system, distributed Microgrid Controllers, or a distributed energy resource management system.

- **Identification and validation of key functions of energy storage systems within a Microgrid**
  Functionality of the energy storage system within the Microgrid took place in many forms. The key modes of operation: constant charge and discharge, peak shaving, and reactive power were leveraged to accommodate many functions based on various triggering events. These included circuit load management, optimization of generator loading, demand response support, arbitrage, and VAr control in both grid connected and island mode operations. In addition, experience was gained with respect to the need for energy storage management where future operational requirements are identified and approaches are developed so that the storage is at the desired state of charge in time to execute the desired future mode of operation. Due to the current high capital cost of storage systems, the storage system must contribute to several system benefits in order to be cost effective. The demonstration also showed that the arbitrage operations do not derive a high economic value for the Microgrid but should be taken into account as a secondary consideration when planning storage system operations. The demonstration also showed that having four quadrant operation capabilities (injecting or consuming VArs while charging or discharging) was beneficial to the flexibility of operation to support Microgrid activities.

- **Develop and implement a pricing-based strategy to affect the operation of resources within a Microgrid**
  The team successfully developed a pricing model that was used by multiple Microgrid resources to influence and affect operations, particularly reducing demand to provide demand management resources to support the microgrid circuit load. The idea to implement pricing was to have a market-based trigger that is used to influence Microgrid operations. In the microgrid demonstration, pricing signals influenced demand response with the objective of reducing the customer load. Demonstrations were conducted where a wholesale price was calculated based on a weighted average of Microgrid resource contributions to the planned energy supply of the Microgrid for each hour of the day. These prices where then converted to a “simulated” retail price that was presented to customer’s in home display units and HAN devices. The HAN devices responded as programmed during these pricing event demonstrations. As discussed in the storage system findings, the cost of energy was taken into account when charging the storage system. This allowed for the cost of energy being provided to the Microgrid when the storage unit was discharging to be accurately accounted. Thus, during times of high whole costs, a storage unit that had been charged during the off-peak low cost time periods could be used to reduce the cost of energy delivered to the Microgrid during peak time periods. The demonstration showed that this pricing-based strategy could effectively be used as a control signal for Microgrid Operations.

- **Determine if there are approaches to utilizing demand response resources in a manner similar to generation in terms of dispatchability, reliability, and localization**
  The team envisioned that the use of home area networks combined with a central demand response control system could be used in a Microgrid to manage the demand response resource in a manner similar to the generators or the storage system. In order to accomplish this, demand response needs to be controllable, predictable, and repeatable. This proved to be challenging for the demonstration due to the resource load forecast model used, the post event estimating approached employed, the small loads being managed (mainly plug load controllers), and the small population of customers in the program. The project did successfully implement a demand response model that could execute demand response events for a targeted area of the service territory down to a section of a specific circuit. The demand response was not a major factor in Microgrid resource planning during the Microgrid Optimization Phase of the project due to its low capacity impact. Demand response has been identified as an area of further work that has the potential to be improved for both Microgrid applications and overall demand response activities.

- **Demonstrate the ability to routinely operate multiple Microgrid Resources through a consolidated monitoring and control interface**
  Routinely operating utility-owned generation and energy storage systems on the distribution network is a new concept for utility distribution system operators. In addition, these devices do not currently have a communication standard such as DNP3 that allows for a more straight forward integration to a typical SCADA system. The units integrated to the Microgrid offered a Modbus protocol for communications and control. In addition, these types of resources have unique operating characteristics and control sequences can be vendor-specific. In order to effectively operate these systems, a Microgrid Visualizer was developed and implemented that provided a consolidated interface to the equipment controls and monitoring. The Visualizer allowed for control of the Microgrid resource both from within the Microgrid yard (control van) and remotely from SDG&E offices in San Diego. This system also provided the function of data collection and archiving for project reporting and analysis.

- **Demonstrate seamless planned island operations on a circuit without affecting customers**
  One of the highlights of the Demonstration project was the ability to effectively island the entire Microgrid supporting more than 600 customers. The islanding demonstrations transitioned into and out of the island mode without affecting the quality of service to the customers (seamless transitions without an outage or flicker). The island demonstrations evaluated the island operations with the DG units only, the DG units operating with the SES in both charge and discharge modes, and the DG units operating with the SES unit

providing a majority of the reactive power requirements. All demonstrations were successful and demonstrated the stated operational objectives.

Additionally, the Microgrid was operated in island operation twice during the contract period to provide service to customers who would have otherwise had an extend loss of service.

- The first event took place on June 6, 2012 for a planned outage for the Borrego Springs community so that a new commercial 26 MW solar project could be safely interconnected to SDG&E's system. The outage began at 10:00 PM and lasted for approximately 5 ½ hours supplying energy to a total of 2,128 customers. This was a pre-planned operation in which the Microgrid was temporarily re-configured to service all three of the circuits at the substation.
- The second event took place on September 6, 2013 when severe weather of high winds, heavy rain and a lighting storm caused an unplanned outage of service to the entire substation. This manual black start operation primarily used the generators which were operated continuously on September 6 from 16:48 PM to 3:10 PM on September 7. As sections of the circuits were cleared or repaired, additional customers were energized as presented in the following table:

Date	Time	Customers with Service
9/6/2013	2:20 PM	0 – Start of outage
9/6/2013	6:50 PM	162 – Powered by Microgrid
9/6/2013	7:50 PM	529 – Powered by Microgrid
9/7/2013	7:25 AM	754 – Powered by Microgrid
9/7/2013	8:33 AM	1,056 – Powered by Microgrid
9/7/2013	2:00 PM	All – All repairs complete and grid service resumes

- **Utilize the outcomes of the demonstration to identify future cost-effective deployments of Microgrids in the service territory -** The lessons learned and the quantified benefits from the Microgrid demonstration were used to identify other potential cost effective Microgrid applications in the SDG&E service territory. Applications were identified where there is a high potential to improve existing distribution operations and classified with their associated characteristics as follows:
    - Commercial and Industrial Consumers (C&I)
        - Behind the meter
        - High reliability requirement
        - Third-party finance of projects
        - Community-level
        - Increasing use of PV
        - Potential low cost of capital

- Communities with Challenges with high Penetration of Solar PV (HPV)
  - Isolate one or more stability issues
  - Adapt community or network to stability issues
- Weak Points in the Distribution Network
  - Topology
  - Unexpected growth
  - Nodal issues
- End of Circuit (EOC)
  - Voltage support
  - Conservation voltage reduction
  - Avoid re-conductor on load growth
- Other (O)
  - Sites with special needs (sports venues, data centers, hospitals, etc.)

The key findings from the cost benefit analysis are that potential deployment of cost-effective Microgrids and DER are not as broad and deep as expected. A total of 28 cost-effective applications were identified:

- 10 MW Microgrid: quantity = 2
- 1 MW Microgrid: quantity = 10
- 300 kW DER solutions: quantity = 18

For utility-based Microgrids, it is important to structure a selection process that is based on the following:

- Benefit Characteristic Solutions need to be tied to the needs of the territory's electric system
- Strategic Priorities need to be identified and ranked
- Identified Solutions need to be designed to deliver the benefits identified in the Benefit Characteristic Solutions
- Characterize the territory, or network topology, to link electric loads with locations and a consumer population of likely participants
- The analysis needs to be based on a life cycle cost model that must include capital costs, utility integration costs, and equipment O&M expenses

It is important to develop a cost benefit selection structure that enables a criteria based selection using the best site solution-benefit pairings to ensure the maximum economic returns.

[End of Report]