Final Technical Report

Project Title: Comprehensive Solutions for Integration of Solar Resources into Grid Operations

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Executive Summary

The need for proactive closed-loop integration of uncertainty information into system operations and probability-based controls is widely recognized, but rarely implemented in system operations. Proactive integration for this project means that the information concerning expected uncertainty ranges for net load and balancing requirements, including required balancing capacity, ramping and ramp duration characteristics, will be fed back into the generation commitment and dispatch algorithms to modify their performance so that potential shortages of these characteristics can be prevented. This basic, yet important, premise is the motivating factor for this project. The achieved project goal is to demonstrate the benefit of such a system.

The project quantifies future uncertainties, predicts additional system balancing needs including the prediction intervals for capacity and ramping requirements of future dispatch intervals, evaluates the impacts of uncertainties on transmission including the risk of overloads and voltage problems, and explores opportunities for intra-hour generation adjustments helping to provide more flexibility for system operators. The resulting benefits culminate in more reliable grid operation in the face of increased system uncertainty and variability caused by solar power. The project identifies that solar power does not require special separate penetration level restrictions or penalization for its intermittency. Ultimately, the collective consideration of all sources of intermittency distributed over a wide area unified with the comprehensive evaluation of various elements of balancing process, i.e. capacity, ramping, and energy requirements, help system operators more robustly and effectively balance generation against load and interchange. This project showed that doing so can facilitate more solar and other renewable resources on the grid without compromising reliability and control performance.

Efforts during the project included developing and integrating advanced probabilistic solar forecasts, including distributed PV forecasts, into closed –loop decision making processes. Additionally, new uncertainty quantifications methods and tools for the direct integration of uncertainty and variability information into grid operations at the transmission and distribution levels were developed and tested.

During Phase 1, project work focused heavily on the design, development and demonstration of a set of processes and tools that could reliably and efficiently incorporate solar power into California's grid operations. In Phase 2, connectivity between the ramping analysis tools and market applications software were completed, multiple dispatch scenarios demonstrated a successful reduction of overall uncertainty and an analysis to quantify increases in system operator reliability, and the transmission and distribution system uncertainty prediction tool was introduced to system operation engineers in a live webinar. The project met its goals, the experiments prove the advancements to methods and tools, when working together, are beneficial to not only the California Independent System Operator (CAISO), but the benefits are transferable to other system operators in the United States.

Table of Contents

1. Background

Some wind forecast service providers offer uncertainty information for their forecasts. For instance, AWS Truepower (AWST) [1] and Vaisala [2] companies developed wind power generation forecasting tools with built-in capability to assess wind generation uncertainty. Similar tools have been developed in Europe. In the context of a European Union project, ANEMOS, a tool for online wind generation uncertainty estimation based on adaptive resampling or quantile regression has been developed [3]. AWST and Energy and Meteo Systems have developed tools for wind generation forecasting, assessing the uncertainty ranges associated with wind forecast, and predicting extreme ramping events [4], [5]. Pinson et al. [6] discusses a wind generation interval forecast approach using the quantile method. Reference [7] used statistical analysis based on standard deviation to predict wind generation forecast errors. Work is underway to incorporate these uncertainties into power system operations [8]–[10]. Integration of wind generation forecast uncertainty into the security constrained unit commitment (UC) procedure is also a very important challenging problem and it is considered in [10]–[12].

Unfortunately, in many cases these efforts are limited to wind generation uncertainties only and ignore additional sources of uncertainty such as system loads and forced generation outages[1]. Moreover, these approaches, while considering the megawatt imbalances, do not address essential characteristics such as ramp (megawatts per minute) and ramp duration uncertainties (minutes), required by the generators participating in the balancing process.

This project addresses the uncertainty problem comprehensively by including all types of uncertainties (such as load, variable generation, etc.) and all aspects of uncertainty including the ramping requirements. The main objective is to provide rapid (every 5 min) look-ahead spanning 1.5 hours ahead to assess the resulting uncertainty ranges for the balancing effort in terms of the required capacity, ramping capability, and ramp duration. The uncertainty range is called a "performance envelope" in this work. A methodology for self-validation of the predicted performance envelope has also been developed [14], [15].

This project aims to demonstrate that a practical deployment of such a system could be achieved and would have far-reaching national and international impacts. The system operators would then be able to determine the potential future reliability impacts of solar resources, other renewables and sources of uncertainty on the system reliability, their probability and timing, as well as the corrective actions needed to minimize the risk (e.g. in terms of balancing capacity, ramping capability, and transmission system limits). Moreover, the uncertainty and variability information can be fed directly into the unit commitment and dispatch procedures, so that the system will be automatically positioned to address potential system imbalances and transmission violations. Although the project focus is California, it has profound impacts on the rest of the country. Ultimately, this project will significantly contribute to the EERE SunShot objective "to support the development of innovative, cost-effective solutions to boost the amount of solar energy that utilities can integrate seamlessly with the national power grid".

This effort will advance previous research efforts at Pacific Northwest National Laboratory (PNNL) and test its integration capabilities with operational tools in use at CAISO. This project

[1] An exception is the comprehensive tool developed by Red Eléctrica de España (REE), the Spanish Transmission System Operator [13].

captures the uncertainty and variability present in power forecasting, load, and other variables that challenge the flexibility of grid balancing with the following efforts:

- Solar forecast algorithms aim to reduce the uncertainty range rather than just the standard deviation or root mean square value of the forecast error. The difference between the old and the new objectives becomes evident when we deal with non-parametric distributions and non-stationary distributions. The size of uncertainty interval corresponding to a certain level of confidence directly influences the balancing requirements.
- Forecast geographically distributed PV generation mixed with local loads and other local generation resources.
- Provide for concurrent consideration of all sources of uncertainty and variability (solar generation, system load, uninstructed deviations of conventional units, and forced outages).The concurrent consideration will help to reduce the overall uncertainty and, consequently, the resulting balancing effort required from the grid operators.
- Apply geographically and temporally distributed forecast models to help quantify the collective impacts of all sources of renewable generation uncertainty in their interaction on the transmission system.
- Proactive minimization of uncertainty intervals by separating more predictable, slower quasi-deterministic components from less predictable, faster components in the forecast errors.
- Quantify uncertainty and variability on the transmission system based on the risks of transmission problems (overloads, voltage problems) in various contingencies.
- First-ever industrial implementation of close loop real-time uncertainty-based unit commitment and dispatch procedures helping to exercise preventive, rather than corrective, control and avoid accidents when the system balancing capacity and ramping capability is not sufficient to address random deviations of the resulting system load.
- Quantify the system balancing requirements based on the Control Performance Standard 1[2] (CSP1) and new scheduling requirements recently introduced into the grid control practices.
- Incorporate ramping information provided by forecasts in the unit commitment and dispatch processes.
- Develop multi-dimensional uncertainty quantification procedures including a concurrent consideration of the capacity, ramp rate, and ramp duration requirements to the balancing generators.

The collective consideration of all sources intermittency distributed over a wide area unified with the comprehensive evaluation of various elements of balancing process, i.e. capacity, ramping, and energy requirements, will help system operators more robustly and effectively balance generation against load and interchange to ultimately provide for more solar and other renewable resources on the grid, without compromising reliability and control performance.

The need for the proactive integration of uncertainty information into system operations and probabilistic close-loop controls is widely recognized, but rarely implemented in real systems. This project leads toward a practical deployment of such systems in California. The project will help system operators clearly identify the potential future reliability impacts of solar resources and other renewables as well as all other concurrent sources of uncertainty on system reliability,

[2] CPS1 is a statistical measure of area control error (ACE) variability. It measures ACE in combination with the interconnection frequency. The CPS1 formula was developed on a conformance scale, therefore values over 100% are not only desired, but also expected.

including an assessment of potential adverse impacts, their probability and timing, and the recommended corrective actions needed to minimize risk by adding more flexible balancing capacity, ramping capability, and/or adjusting transmission limits.

2. Project Objectives

As of October 2015, California leads the Nation with its 421,803 solar projects and 3,340 MW of solar capacity installed in the state. The goal of the California "Go Solar" program is to deploy 3,000 megawatts of solar systems on homes and businesses by the end of 2016. To meet its 33% renewable energy goal, along with the growing solar power, California is aggressively connecting other types of renewables, including wind, geothermal, and small hydro resources. Additionally, California Governor Jerry Brown has proposed an expansion of the state's renewable energy goals to 50% by 2030. With the current renewable energy target of 33% and the potential increase to 50%, utilities and system operators in California are looking for new solutions to integrate variable renewable generation at the transmission and operational levels. The California experience and know-how will contribute significantly to similar efforts in the rest of the country.

The efforts undertaken in this project specifically address some of the challenges faced to reliably and efficiently operate the grid with a continued increase solar and other renewable energy sources. The objective of the project is to develop a set of processes and tools to reliably and efficiently connect increasing solar power in California and incorporate specific processes and tools into the mainstream utility power system operations to handle high penetrations of renewables. The effort includes developing and testing tools to help to predict the system balancing needs for future dispatch intervals, evaluating the impacts on the transmission system, and investigating opportunities for intra-hour interchange adjustments to help to explore more reliable flexibility balancing opportunities for system operators at the transmission and distribution levels.

Unique features of this project include:

- Forecasting algorithms that aim to reduce the uncertainty range rather than just the standard deviation or root mean square value of the forecast error. The forecasts were developed to deal with non-parametric distributions and non-stationary distributions. The size of uncertainty interval corresponding to a certain level of confidence directly influences the balancing requirements.
- Concurrent consideration of all sources of uncertainty and variability (solar and wind generation, system load, uninstructed deviations of conventional units, and forced outages).The concurrent consideration helps reduce the overall uncertainty and, consequently, the resulting balancing effort required from the grid operators.
- Geographically and temporally distributed forecast models help to quantify the collective impacts of all sources of uncertainty and their interaction on the transmission system.
- Proactive minimization of uncertainty intervals by separating more predictable slower quasi-deterministic components from less predictable faster components in the forecast errors.
- Quantification of uncertainty and variability on the transmission system based on the risks of transmission problems (overloads, voltage problems) in various contingencies.

- Independent System Operator (ISO) level experiment of close loop real-time uncertainty-based unit commitment and dispatch procedures to exercise preventive rather than corrective control and avoid accidents when the system balancing capacity and ramping capability is not sufficient to address random deviations of the resulting system load.

Phase 1 of the project focuses on the development of advanced solar generation forecasts, and advancement of the PNNL ramp and uncertainty prediction tool (RUT) to help to predict system balancing needs for future dispatch intervals, evaluate the impacts on the transmission system (the risk of overloads and voltage problems), and investigate opportunities for intra-hour interchange adjustments to help to explore more reliable and flexible balancing opportunities for system operators at the transmission and distribution levels. Phase 1 efforts also included a process to integrate the RUT output with the Siemens market software used at CAISO.

Phase 2 expands on the connectivity of Siemens security-constrained unit commitment (UC) and economic dispatch (ED) procedures used by CAISO with the RUT advancements developed in Phase 1 to perform experiments using CAISO data as input. The experiments are performed in a stand-alone development platform at Siemens offices that replicates the CAISO EC and ED procedures. Phase 2 efforts also include a performance evaluation of the PNNL probabilistic transmission uncertainty tool (TUT) by using operational level data and rooftop solar forecasts developed in Phase 1. The TUT output will be analyzed to show how the tool can improve situation awareness and reliability by predicting potential violations of the CAISO transmission/distribution system limits and associated risks on critical lines/paths in the system, for all credible contingencies, as well as the expected time to violations.

A Go/NoGo decision point was based on Tasks 1-4 and the target of at least 85% of the milestone items being reached (85 points out of 100). The Department of Energy (DOE), in conjunction with the project team, determined that the work performed in Tasks 1, 2, 3, and 4, although delayed due to data availability issues, showed adequate project advancement and risk avoidance and warranted the continuation of project efforts on Tasks 5, 6, & 7.

Below is a summary of the Tasks undertaken in the project.

- **Task 1: Advanced forecasting of solar generation**
    - Generate deterministic and probabilistic solar production forecasts for utility scale and rooftop PV sites, relevant to CAISO system management, in the CAISO balancing area. Solar forecasts include probabilistic 5 minute intervals spanning 90 minutes beyond the start of each forecast file.
    - Generate one year (2013) of deterministic and probabilistic solar production forecasts for utility-scale PV sites, relevant to CAISO system management, in the CAISO balancing area.
    - Go/NoGo Impact: *15 points*. Successful creation of new probabilistic and deterministic forecast data with no missing forecast variables for every interval during the 1 year period. The success metric is the creation of new rooftop PV forecasts, new probabilistic forecasts, with deterministic forecasts for every CAISO solar resource.

- **Task 2: Prediction of real-time balancing capacity and ramping requirements for closed-loop uncertainty integration with CAISO systems**
    - This task addresses integration of probabilistic forecasts into tools for power grid operations and markets and implement/demonstrate connectivity between probabilistic solar forecast and the RUT. Several subtasks are included in Task 2.
        - Subtask 2-a: Integration of probabilistic forecast with the RUT.
        - Subtask 2-b: Creation of statistical methods to address non-stationary and non-parametric characteristics of forecast errors.
        - Subtask 2-c: Modernization of a real-time balancing capacity and ramping requirements prediction tool to reflect the system operators changing forecast engines and integration needs with market applications. The tool will be tested in a development environment but not implemented into a system operator's production environment. The successful test would pass self-validation procedures developed by PNNL[3].
            - Compare 2013 RUT PV forecasts to AWS Truepower forecasts and actual generation to demonstrate any advantage or disadvantage of the two approaches.
    - Go/NoGo Impact: *35 points*. Documented interface specification and implementation of connectivity of solar forecasts and the RUT (*15 points*). The new methods developed in 2-a, 2-b and 2-c should improve balancing requirements in the system by reducing uncertainty ranges for the net load by 5-10% under normal conditions (*10 points*) and by 10-15% during ramping periods (*10 points*), over existing techniques used by CAISO over the same period of time.
- **Task 3: Active Integration of uncertainty and variability information into power system operations**
    - Progress will be made towards incorporating the uncertainty information into UC and dispatch market procedures. Task 3 will consist of the following subtasks.
        - Subtask 3-a: Define and document the methodology to be used to incorporate the new tool into the Siemens unit commitment and dispatch market procedures for use in grid operations.
        - Subtask 3-b: Initial offline testing of integration methodology will be performed. The integrated tool will be vetted to confirm that it correctly uses existing processes in the Energy Management System (EMS) and market systems to check the sufficiency of balancing resources within the range of uncertain system requirements.
        - Subtask 3-c: Write an intermediate report summarizing the results of Tasks 1-3.

[3] Etingov PV, J Ma, YV Makarov, and K Subbarao. 2012. Online Analysis of Wind and Solar Part I: Ramping Tool. PNNL-21112, Pacific Northwest National Laboratory, Richland, WA.

- Go/NoGo Impact: *40 points*. Documented integration methodology and detail specifications (*15 points*), successful initial offline testing results with report (*15 points*), report summarizing Tasks 1-3 (*10 points*).

- **Task 4: Provide DOE and public accessible data created from project**
  - This task will collect and make available to the DOE for public consumption on the GEARED portal all data that was generated as part of the scope of this project that is allowable given the potential proprietary or sensitive nature of the data. When applicable, data will be masked or normalized to protect confidential or sensitive data.
  - Go/NoGo Impact: *10 points.* Data (including masked or normalized data) that was generated as part of the scope of this project in Budget Period 1 provided to DOE no later than 30 days after the conclusion of Budget Period 1.

- **Task 5: Active integration and quantification of uncertainty and variability information into power system operations**
  - This task finalized connectivity of the RUT output and actively engaged with offline CAISO market applications. Experiment results are quantified and summarized. Task 5 belongs to Stage Gate 2 and proceeded because approval was received from the DOE to continue project work beyond Stage Gate 2. Task 5 includes the following subtasks.
    - Subtask 5.1: Full integration in offline CAISO market applications with CAISO data and RUT output. All of the following items were performed in this Subtask: 1) analysis and develop way for data formats and structures used by CAISO, Siemens, and the uncertainty tool to connect; 2) modify the Oracle database to incorporate additional data formats required for connectivity; 3) modify the uncertainty tools algorithms for connectivity; 4) perform implementation of methods developed in Task 3, and; 5) run initial experiment to test the integrated tool. The connection of the tool with a market application environment will allow the project team to demonstrate the cost savings and other advantages of integrating advanced solar forecasts into the uncertainty-based controls. Experiments included the following dispatch scenarios, “business as usual”, incorporation of uncertainty characteristics into unit commitment and economic dispatch procedures, and the reduction of uncertainty by using advanced forecasting algorithms.
    - Subtask 5.2: Conduct analyses to quantify the actual cost of uncertainty for the system operator level and uncover other advantages of the integrated approach using uncertainty-based controls. In this subtask, three results will be compared: 1) the cost of dispatch in the CAISO “business-as-usual” case; 2) the cost of dispatch when the uncertainty characteristics are incorporated into unit commitment and economic dispatch procedures, and; 3) the cost of dispatch when the uncertainty is reduced by using advanced forecasting algorithms using Siemens security constrained unit commitment (SCUC) and security constrained dynamic dispatch (SCDD) applications. Project efforts

for Budget Year 1 are represented by four major tasks and several milestones, as shown in Table 1.

- **Task 6: Transmission and distribution system uncertainty prediction tool**
    - This task will improve the prototype software transmission tool to enhance grid operator situation awareness and reliability. Task 6 includes the following subtasks.
        - Subtask 6.1: Utilize real system operations data to evaluate the performance of the transmission tool and analyze the results. Historical data will be analyzed to re-examine the proximity of violations on major paths in and around the operating system. The goal is to demonstrate how the probabilistic transmission tool can improve situation awareness and reliability by predicting potential violations of the transmission/distribution system limits and associated risks on critical lines/paths in the system, for all credible contingencies, as well as the expected time to violations.
        - Subtask 6.2: The transmission tool and results of Subtask 6.1 will be introduced to system operation engineers through a workshop. A report will be developed defining how the tool could be incorporated with market systems.
        - Subtask 6.3: Write a final report summarizing the results of the project with particular focus on Tasks 5-6.
- **Task 7: Provide DOE and public accessible data created from project**
    - This task will collect and make available to the DOE for public consumption on the GEARED portal all data that was generated as part of the scope of this project that is allowable given the potential proprietary or sensitive nature of the data. When applicable, data will be masked or normalized to protect confidential or sensitive data.

Table 1. Major Tasks and Milestones of Budget Period 1.

Task	Description	Milestone Target
1	**Advanced Forecasting of solar generation**	
	Generate deterministic and probabilistic forecasts for utility scale PV plants and rooftop site regions identified by CAISO. Generate one year (2013) of solar forecasts for utility-scale sites in CAISO.	Delivery of forecast data
2	**Ramp and Uncertainty tool integration with offline CAISO system**	
	Integration of PV forecasts with PNNL RUT.	Task Report - Interface Specifications
	Make advancements to RUT and test RUT in development environment.	Task Report - Advancements
	Compare RUT forecasts to AWS Truepower forecasts	Memo Report - Comparison

		Results
3	**Active Integration of uncertainty and variability information into power system operations**	
	Define and document methodology to incorporate RUT data into the Siemens UC and dispatch market procedures. Perform initial offline testing of integration methodology.	Task Report - RUT output and Integration with Flexiramp
	Write an intermediate report summarizing the results of Tasks 1-3	Task Report - Budget Period 1 Summary
4	**Provide DOE and Public Accessible Data Created from this Project**	
	Collect and make available to the DOE for public consumption on the EERE portal all data that was generated as part of the scope of this project that is allowable given the potential proprietary or sensitive nature of the data.	Delivery of public data
GO/NO GO DECISION POINT		
5	**Active integration and quantification of uncertainty and variability information into power system operations**	
	Connect and integrate offline the RUT with Siemens Flexiramp procedures used by CAISO. Run initial experiment to test the integrated tools. Conduct analyses to quantify the economic impact of uncertainty factors on multiple dispatch scenarios including 1) business-as-usual; 2) incorporation of uncertainty characteristics, and; 3) reduced uncertainty with PV forecasts	Task Report - Offline Testing Results
6	**Transmission and distribution system uncertainty prediction tool**	
	The TUT will be introduced to system operation engineers through a workshop. A report will be developed defining how the tool could be incorporated with market systems.	Task Report & Workshop
	Write a final report summarizing the results of the project with particular focus on Tasks 5-6.	Task Report - Budget Period 2 Summary
7	**Provide DOE and Public Accessible Data Created from this Project**	
	Collect and make available to the DOE for public consumption on the EERE portal all data that was generated as part of the scope of this project that is allowable given the potential proprietary or sensitive nature of the data.	Delivery of public data

3. Project Results and Discussion

Significant and meaningful advancements have been made in the project. The following describes a high-level quantitative comparison of anticipated project outcomes against realized results. Progress against award milestones did lag in the project due to delays in obtaining data from CAISO necessary to perform the experiments. Progress on the project and Tasks during budget period 1 (BP1), although delayed, were worthwhile and helped move the project effort forward enough to provide adequate justification for the project team and DOE staff to continue project efforts to complete BP1 tasks and begin efforts on budget period 2 (BP2) tasks. Thus the Go/No Go decision point resulted in the continuation of the project into BP2.
The experimental efforts in BP1 (Tasks 2 and 3) relied heavily upon the receipt of load data from CAISO to perform the pilot testing and evaluation. The receipt of data delivery from CAISO was delayed, requiring the Project Team to re-evaluate the project's scope of work and its applicability to the primary stakeholder.

The original scope of work was re-assessed as a result of the delay to determine its applicability to CAISO, who modified their market structure during the BP1. In May 2014, CAISO modified their market data formats by introducing 5-minute resolution forecasts and 15-minutes schedules for their interchange, based on Federal Energy Regulatory Commission Order 764. The original scope of work relied upon using historical load data to design, implement and test the integration of the PNNL and Siemens tools. Efforts to obtain data prior to this transition, in the old market format were unsuccessful, and would have required an extensive effort by CAISO staff to retrieve ultimately making access to the older data inaccessible. Moreover, the original scope of work relied on a historical application, and would result in a tool development that would have limited real-world application, following the CAISO's market transition if the project relied on 2013 data.

Flexible ramping requirement as a system level constraint is already implemented in CAISO markets to cope with the variability of PV and wind energy generation. However, with the rapidly increasing meteorological-dependent generation and their characteristic large range of variability combined with other uncertainties associated with load as well as operational system conditions it is extremely difficult to calculate system flexible ramping requirements in a deterministic manner. Hence, CAISO is turning to a more detailed flexible ramping requirement calculation application developed by this DOE sponsored project.

The CAISO is the primary testbed and a critical project participant, most likely to integrate the project's results in a real-time application. Relying on the older data formats as originally scoped, creates long-term problems for the potential future integration of the project tools within the CAISO systems. It became paramount for real-world application and testing that the project needs to reflect actual operations if the deliverable will serve the long-term interest of its stakeholders. Therefore, mitigation efforts began to rework the study period to reflect the availability of the new CAISO market data in its present format in order to satisfy the BP1 milestones for Tasks 2 and 3.

CAISO was successful in providing data that proved useful for the experiments. The period of data that was received was for a later period of time than originally targeted in the project. This required some rework for the project team to refocus the experiments as well as the creation of a new set of solar forecasts.

Also, the initial focus of the project experiments to avoid price spike cases that were caused by solar energy variability with the goal to validate the methods and advancements, as implemented in the offline environment, over past CAISO market production cases. This experiment design would ensure the current project implementation would prevent such undesirable price excursions in the real-time market. After collecting and reviewing all five minute interval prices for 2014, the project team determined that the observed price spikes were not the result of system impacts stemming from solar generation variability. The solar generation variability price spike relationship was ruled out by comparing the price patterns to that of renewable energy generation during the price spike instances. There is sufficient logical reasoning for why the project team uncovered these findings. The existing CAISO market applications formulation as existed, say back in October 2014, for flex ramp constraints in the markets had already been designed to limit price excursions in the event unexpected variability of renewable energy. In general, for energy products in the CAISO market, when there is ramping insufficiency irrespective of the root cause, positive or negative price spikes are the associated symptom that are observed and they fade away when the ramping and dispatch catch up, albeit over a longer period of time than would have been desired. At the time of market execution (binding for a time interval in the future), the set aside flex ramp quantities had prevented the ramping insufficiency, and subsequently the price spikes as well which are associated with this phenomenon.

With the above reasoning we can understand that while analyzing past prices and solar energy variability data sets of year 2014, what we instead and indeed observed were reliability violations (frequency and area control error (ACE)) during high amounts of solar variability. We did not observe the price spikes originally expected as they were already mitigated by the flex ramp up constraint inherent to the Siemens market applications for CAISO. The project team, through guidance from CAISO and agreement from DOE, began looking at the impact of solar ramping on system reliability, specifically related to Control Performance Standards. The control performance standard used and suggested by CAISO was CPS1 which is a statistical measure of ACE variability. CPS1 measures ACE in combination with the interconnection frequency. CPS1 as a measure is intended to provide control areas with a frequency sensitive evaluation of how well it is meeting its demand requirements and therefore is relevant to industry and this project. This shift in focus from price spike to reliability violation avoidance further improved the forecast and flex ramp requirements by means of introducing probabilistic estimates which allow us to address the reliability aspects that were not addressed fully during the actual market runs in real time.

Table 2. Task milestone targets and results.

Milestone	***Metric Definition***	***Success Value***	***Anticipated Outcome***	***Actual Outcome***	***Completed Deliverable***
1-a & 1-b	Generate four months of probabilistic solar forecasts for utility and rooftop PV sites in CAISO balancing area for 2014 and utility PV sites for 2013.	Generate forecast files	100% complete for study time period	100% complete for study time periods	Data
2	Compare several months of 2013 ramp	Compare forecasting	AWST forecast	AWST forecast	Report

	and uncertainty tool PV predictions to forecasts from the advanced forecasting system and actual generation to demonstrate any advantage/ disadvantage of the two approaches.	approaches	shows 5% MAE improvement beyond RUT tool predictions	improves confidence range by 12-31%.	
2-a	Documented interface specifications and implementation of forecast and RUT,	Successful integration of forecast data.	Successful integration of forecast data	Successful integration of forecast data	Report
2-c	Using CAISO data, show improved balancing requirements by reducing uncertainty ranges for the net load over existing techniques used by CAISO over the same period of time.	Reduced uncertainty ranges of net load.	Reduced uncertainty ranges of net load by 5-10% (normal) and by 10-15% (ramp) over actual the results CAISO operations experienced during the same period	Reduced uncertainty ranges of net load by 10-90% during normal and ramp conditions over CAISO operations experienced during the same period	Report
3-a	Define and document methodology used to incorporate the RUT output into the Siemens unit commitment and dispatch market procedures.	Method development and documentation.	Method development and documentation.	Method development and documentation.	Report
3-c	Write an intermediate report summarizing the results of Tasks 1-3.	Report	Report	Report	Report
4	Collect and make available to the DOE for public consumption on the GEARED portal all non-proprietary project data generated	Provide to DOE no later than 30 days after project conclusion	Masked or normalized data uploaded to portal	Masked or normalized data uploaded to portal	Data
5	Successful implementation in an offline environment to quantify potential system reliability	Success metric will be based on the number of prevented	Real-time market spikes not caused by solar	Quantifiably decreased reliability violations	Report

	benefits	real-time market spikes 75% of the time.	variability		
6-b	The transmission tool prototype will analyze and predict the impact of solar generation (and other sources) on uncertainty and variability on the transmission and distribution systems	Test transmission tool's ability to improve transfer limit.	Improve transfer limits by +/- 1%.	Transfer limits improved by +/- 1%.	Report
6-c	Write a report summarizing the results of Tasks 5-6.	Report	Report	Report	Report
7	Collect and make available to the DOE for public consumption on the GEARED portal all non-proprietary project data generated	Provide to DOE no later than 30 days after project conclusion		Masked or normalized data uploaded to portal	Data Delivery

3.1. Meeting Task Milestones

All Task milestone were successfully met or exceeded except for Task 5 where an outcome that was equally desirable to industry was achieved. The following Section provides both quantitative and qualitative support for the achieved outcomes in the project.

3.1.1. Task 1: Advanced forecasting of solar generation

The work performed on Task 1 included the generation of probabilistic forecasts for both utility scale solar sites and rooftop PV generation. The utility scale forecasts were for the aggregate of all solar generation in CAISO and included 5-minute intervals spanning 90 minutes. The rooftop PV generation forecasts also included 5-minute intervals spanning 90 minutes. Aggregate rooftop forecasts were each generated for the six zones in CAISO that were defined by CAISO staff and shown in Figure 1 and Table 3.

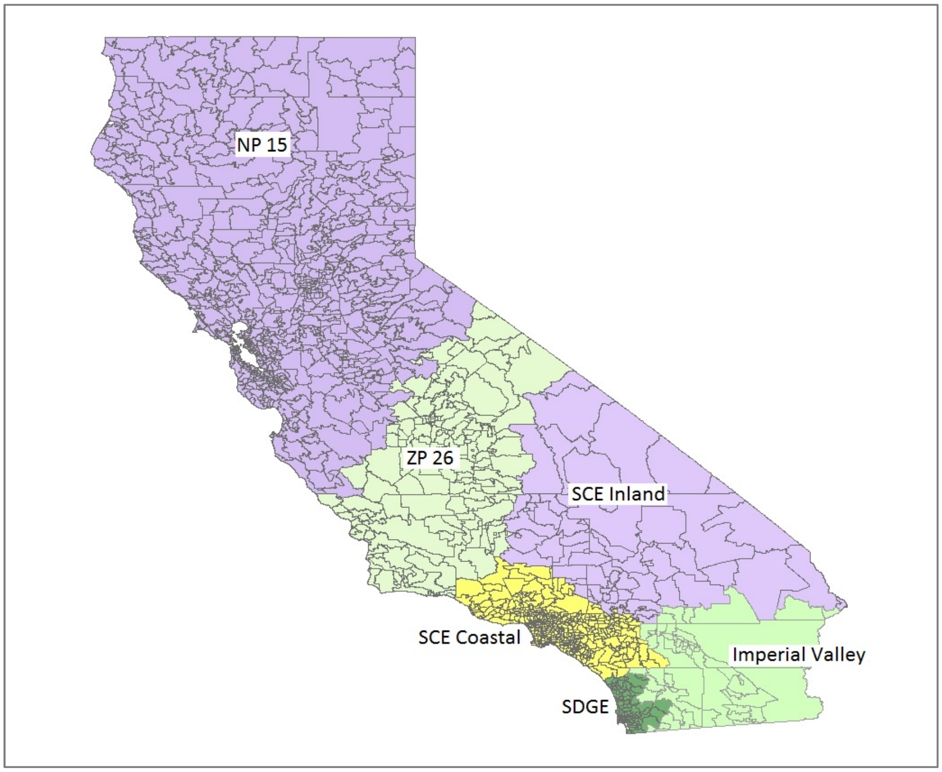

Figure 1. Map of California ZIP codes with shading depicting the six zones used for rooftop generation forecast creation.

Table 3. Installed rooftop PV by zone.

DG Zones	Installed Capacity (MW)
Imperial Valley	64.0
SDGE	161.0
SCE Inland	59.4
SCE Coastal	523.3
ZP26	257.9
NP15	584.8

Probabilistic forecasts were first generated for the 86 utility scale solar plants operating during the October to December 2014 period and separately for 2013 calendar year. Figure 2 provides an example of probabilistic forecasts for a single centralized PV site as well as for all centralized PV plants in California. The power generation at a single site is generally more variable relative to the aggregate of all PV plants. In a climate like California, the low correlation in power generation between geographically dispersed PV plants helps smooth out the power generation fluctuations and thus reduces the volatility.

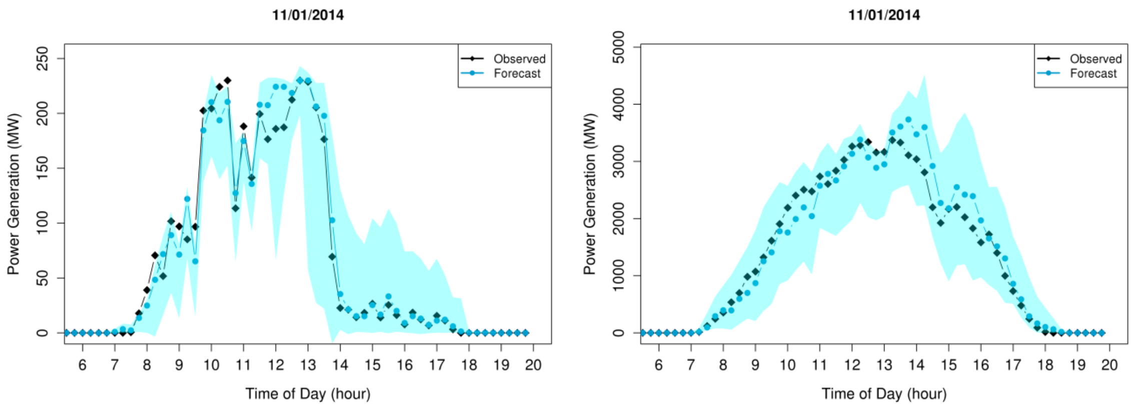

Figure 2. Probabilistic solar power generation forecasts at one centralized PV plant (left panel) and all PV plants in California (right panel) for November 1st, 2014. The blue curve represents the forecast and the blue shaded area corresponds to the 10% and 90% quantiles. The black curve is the actual power generation. For better readability, the observed and forecasted power generation is shown every 15 minutes rather than every 5 minutes.

For the utility scale forecast generation, an ensemble of five numerical weather prediction (NWP) models were used. Three were run with different configurations of the Mesoscale Atmospheric Simulation System (MASS) model (Kaplan et al. 1982, Manobianco et al. 1996) and two configurations of the Weather Research Forecasting (WRF) model. The differences between the three flavors of MASS are the initial and boundary conditions provided to the model. The ensemble members are listed below:

1. MASS initialized with GFS
2. MASS initialized with NAM
3. MASS initialized with GEM
4. WRF initialized with GFS
5. WRF initialized with NAM

The initial and boundary conditions for both MASS and WRF come from two NWP models executed at the National Center for Environmental Prediction (NCEP). They consist of the Global Forecast System (GFS) and North American Mesoscale (NAM) models. They are a core component of the forecast production process used by United States (US) National Weather Service. In addition, one of the ensemble members is initialized by the Global Environmental Multiscale Model developed by Environment Canada. NCEP and Environment Canada update their forecasts every 6 hours and the forecasts are provided at a 1-hour or 3-hour time interval.

Once the NWP model forecasts were generated, statistical models called Model Output Statistics (MOS) were applied to remove or reduce the systematic errors of the NWP models. In addition to reducing the bias, MOS was used as a transfer function to convert the meteorological outputs from each NWP model into solar power generation and therefore acting as a plant-scale power curve taking implicitly into account all kinds of losses experienced at the plant, e.g. soiling, degradation, near shading and electrical. To generate probabilistic forecasts the MOS procedure was based on a quantile regression which is aimed at estimating the median and other quantiles of the response variable (e.g. actual power generation). The input into the MOS algorithm was a subjectively selected set of predictor variables that was consisted of a combination of the output variables from an NWP model and variables derived from those output variables. This MOS technique developed a regression equation to predict the forecasted power generation that corresponds to a specific probability of exceedance (POE). The quantile regression output the forecasted power generation for a total 21 quantiles between 1% and 99%. The 50% quantile represents the deterministic forecast and was extracted from the probabilistic forecast generated by the quantile regression. Given that persistence forecasts tend to perform very well for very short-range time scales such as a 5 to 90 minutes look-ahead period, the probabilistic forecasts were adjusted to reduce the bias in the forecast.

Overall, this ensemble forecasting technique coupled with a quantile regression MOS where the median is adjusted with a persistence forecast was found optimal to the generation of accurate probabilistic forecasts of power generation.

Training data[4] for the forecasting system was extremely scarce for the rooftop PV sites and the computing resource to forecast every 174,000+ rooftop PV sites is cost prohibitive. Thus, the rooftop generation forecasts by zone were created using a different method than the utility scale solar forecasts. Since the utility scale forecasts were already generated, utility-scale solar plants within each zone were aggregated as a foundation to the rooftop forecasts. In most cases utility scale plants are not located in the immediate vicinity of most installed rooftop PV. However, when utility-scale plants are aggregated over a large area such as a zone in Figure 1 the geographical dispersion of the utility scale plants tend to produce aggregate forecasts with comparable statistical behaviors to that of rooftop PV forecasts. This is supported by several research studies [16-17]. For zones with a low sample of utility scale plants, we elected to smooth out the aggregate forecasts using a low pass filter, i.e. a 5-point moving average window. Each utility-scale PV plant contributing to the rooftop forecast creation for a specific zone were given the same weight, i.e. the plant capacity was normalized to 1, in order to favor more geographical dispersion. Finally, the aggregate rooftop forecasts for each zone were scaled to the total installed rooftop PV capacity in each zone as detailed in Table 3.

The anticipated outcome of Task 1 was met and all forecasts were generated. The data is released to the DOE.

3.1.2. Task 2: Prediction of real-time balancing capacity and ramping requirements for closed-loop uncertainty integration with CAISO systems

Prior to the launch of this task, the RUT was solely based on statistical methods and therefore lacked the ability to predict changes in solar production caused by changes in weather. Integrating the quantified uncertainty in solar forecasts generated in Task 1 with the RUT, the overall uncertainty range decreased which can help to reduce system balancing requirements and balancing reserves.

The probabilistic utility scale forecasts generated in Task 1 were successfully integrated into the RUT. The interface process required the creation of a database of forecast data from Task 1. An Oracle database was used as a database server. The RUT uses the following structure for real-time solar forecast tables.

[4] Typically, historical power generation for the last three months at least.

Table 4. Real time forecast table structure

Column Name	Data Type	Primary Key
TimeStamp	TIMESTAMP(6)	1
ZoneID	NUMBER(3,0)	2
Interval_ID	NUMBER(3,0)	3
MW	NUMBER(9,3)	-

- TimeStamp = timestamp – beginning of the first interval (or time when forecast was generated)
- ZoneID = geographical zone ID
- Interval_ID = look-ahead interval ID
- MW_LoadForecast = real-time forecast (MW)

Specification for forecast error CDF table is given in Table 5.

Table 5. Real time forecast error CDF table structure

Column Name	Data Type	Primary Key
TimeStamp	TIMESTAMP(6)	1
Interval_ID	NUMBER(3,0)	2
ZoneID	NUMBER(3,0)	3
Probability	NUMBER(3,0)	4
Error_MW	NUMBER(9,3)	-

- TimeStamp = timestamp – beginning of the first interval (or time when forecast was generated)
- ZoneID = geographical zone ID
- Interval_ID = look-ahead interval ID
- Probability = error probability (%) can accept values: 0, 1, 2, ... , 99, 100.
- Error_MW = forecast error (MW)

A sample of the resulting data is provided in Table 6

Table 6. Data sample

TimeStamp	ZoneID	Interval_ID	Probability	Error_MW
01-MAY-10 12.00.00.000000 AM	1	1	0	-500
01-MAY-10 12.00.00.000000 AM	1	1	1	-480
01-MAY-10 12.00.00.000000 AM	1	1	2	-470
		….		
01-MAY-10 12.00.00.000000 AM	1	1	100	505
01-MAY-10 12.00.00.000000 AM	1	2	1	-600
01-MAY-10 12.00.00.000000 AM	1	2	2	-580

		…….		
01-MAY-10 12.05.00.000000 AM	1	2	100	590

The solar forecast and corresponding statistical characteristics in the form of probability density function (PDF) or cumulative distribution function (CDF) were stored in the RUT database as shown in Figure 4. The previous database design is shown in Figure 3.

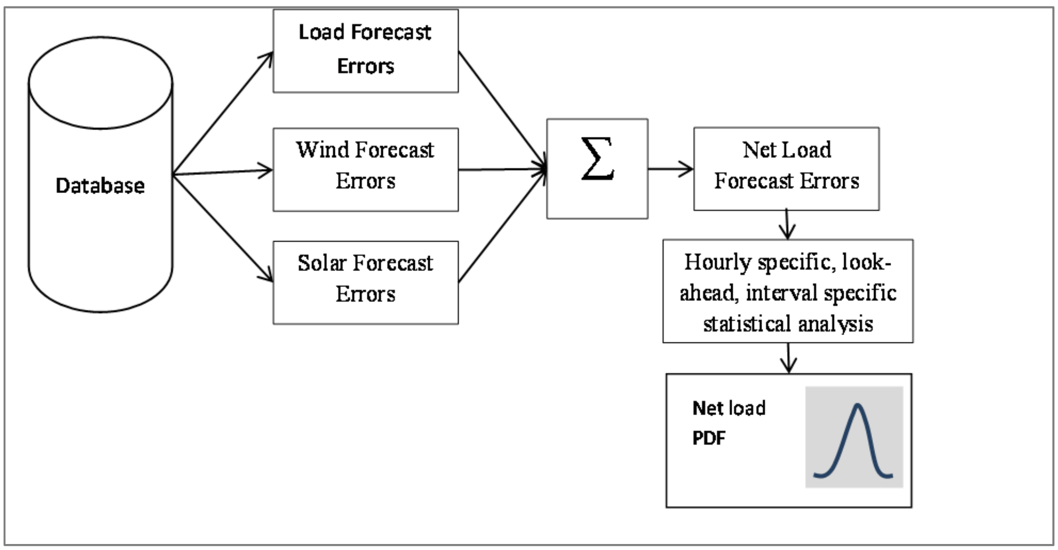

Figure 3. Previously implemented purely statistical PNNL approach

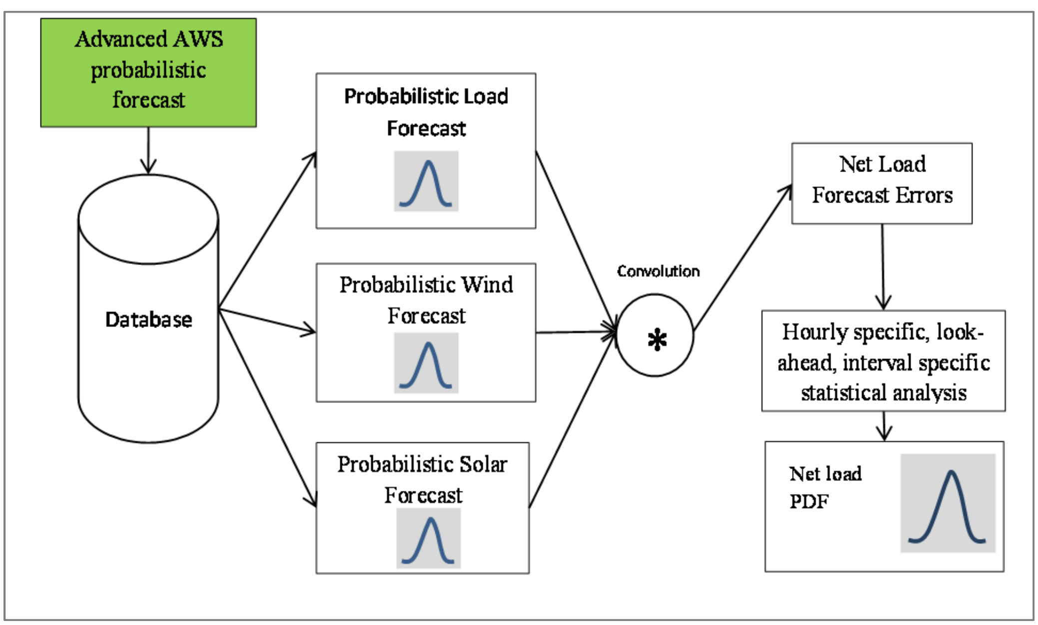

Figure 4. New advanced statistical approach

In addition to integrating the forecasts into the RUT database, several statistical methods were created to address non-stationary and non-parametric characteristics of forecast errors. The methods include a) the decomposition-based short-term forecasting and uncertainty reduction of solar and net load forecast errors using autoregressive integrated moving average approach and b) the nonlinear regression short-term forecast and uncertainty reduction of solar and net load forecast errors using autoregressive regression trees approach. Analysis of these methods showed improvements to balancing requirements in the system by reducing uncertainty ranges for the net load by up to 90% under normal conditions and by up to 80% during ramping periods over existing techniques used by CAISO over the same period of time. This far exceeds the milestone targets of 5-15% improvements. The successful creation of these methods result in more accurate quantification of forecast uncertainty by reducing prediction intervals of short-term forecasts and consequently the balancing requirements in the system.

The decomposition-based short-term forecasting approach was used to address the challenges in forecast error prediction and uncertainty reduction by integrating autoregressive integrated moving average (ARIMA) with seasonal effects and by decomposing signals into trend, seasonal, and noise components [18-19].

The automated-ARIMA integrated with signal decomposition helps alleviate the non-normality and non-stationarity issues such that ARIMA is more applicable. The forecast error data is decomposed in order to extract its trend (long-term upward or downward movement), seasonal (periodical patterns), and random (residual) components [20-22].

There are different ways of defining uncertainty in the forecast errors, either original data or those with reduced uncertainty. For example, the locally averaged forecast errors indicate accuracy of the forecast, while the locally variance (or standard deviation) represents precision of the forecast. An ideal measure of uncertainty should include account for both, and such a measure could be the total sum square (TSS) or its square root. The square root of TSS for each hour can be defined as

$sqrt(TSS) = \sqrt{\sum error_i{}^2}$, i=1,2,…,12 for each hour with 5-min resolution. Figure 5 and Figure 6 show examples on how much such defined uncertainty can be reduced by the decomposition-based ARIMA approach. As shown in the figures, uncertainty in net load forecast errors can be reduced by 10~90%, while uncertainty in solar generation forecast errors can be reduced by 20~80%.

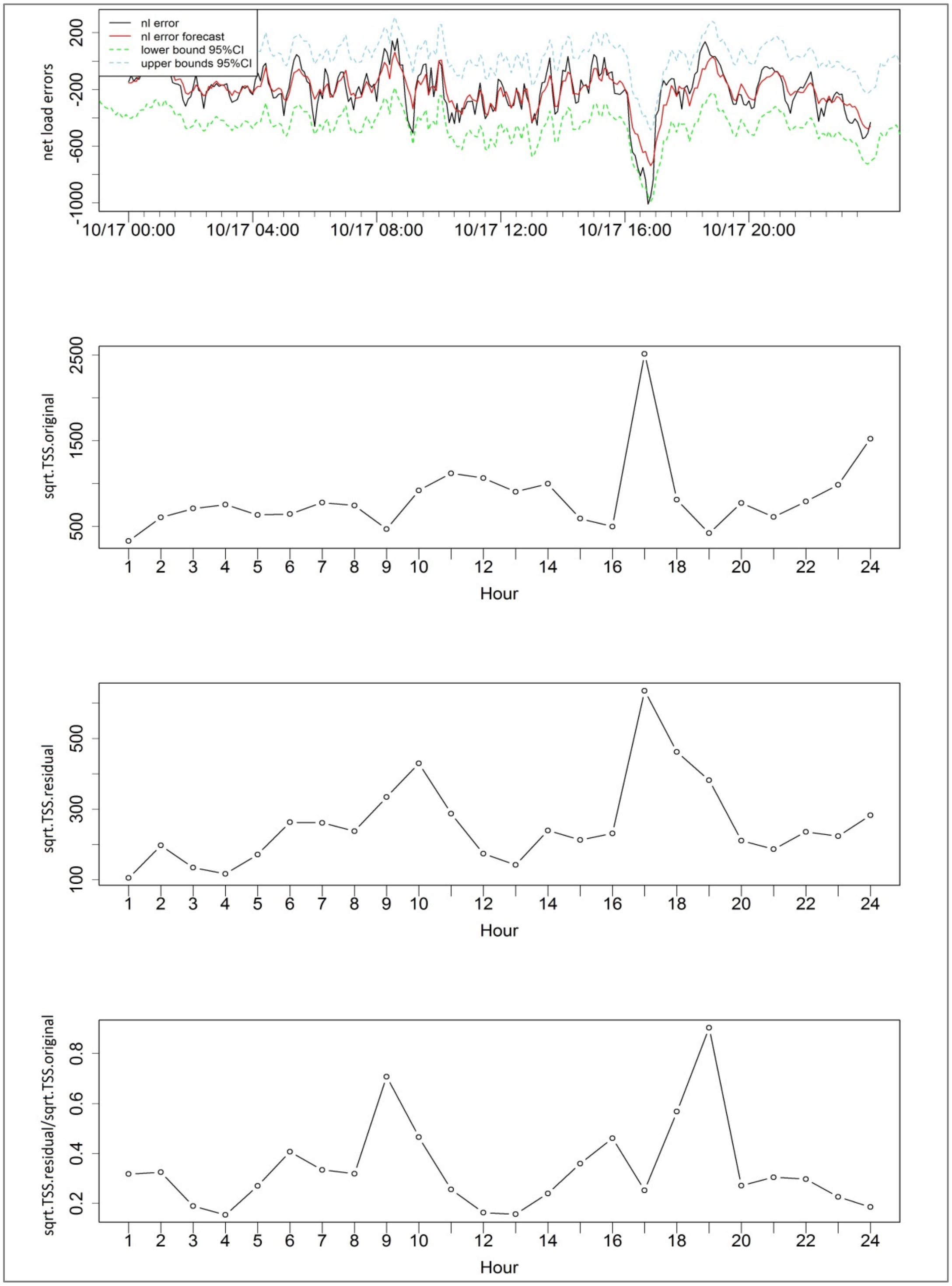

Figure 5. An example of net load forecast errors and its predictions, and the reduced uncertainty relative to the original uncertainty (see bottom panel).

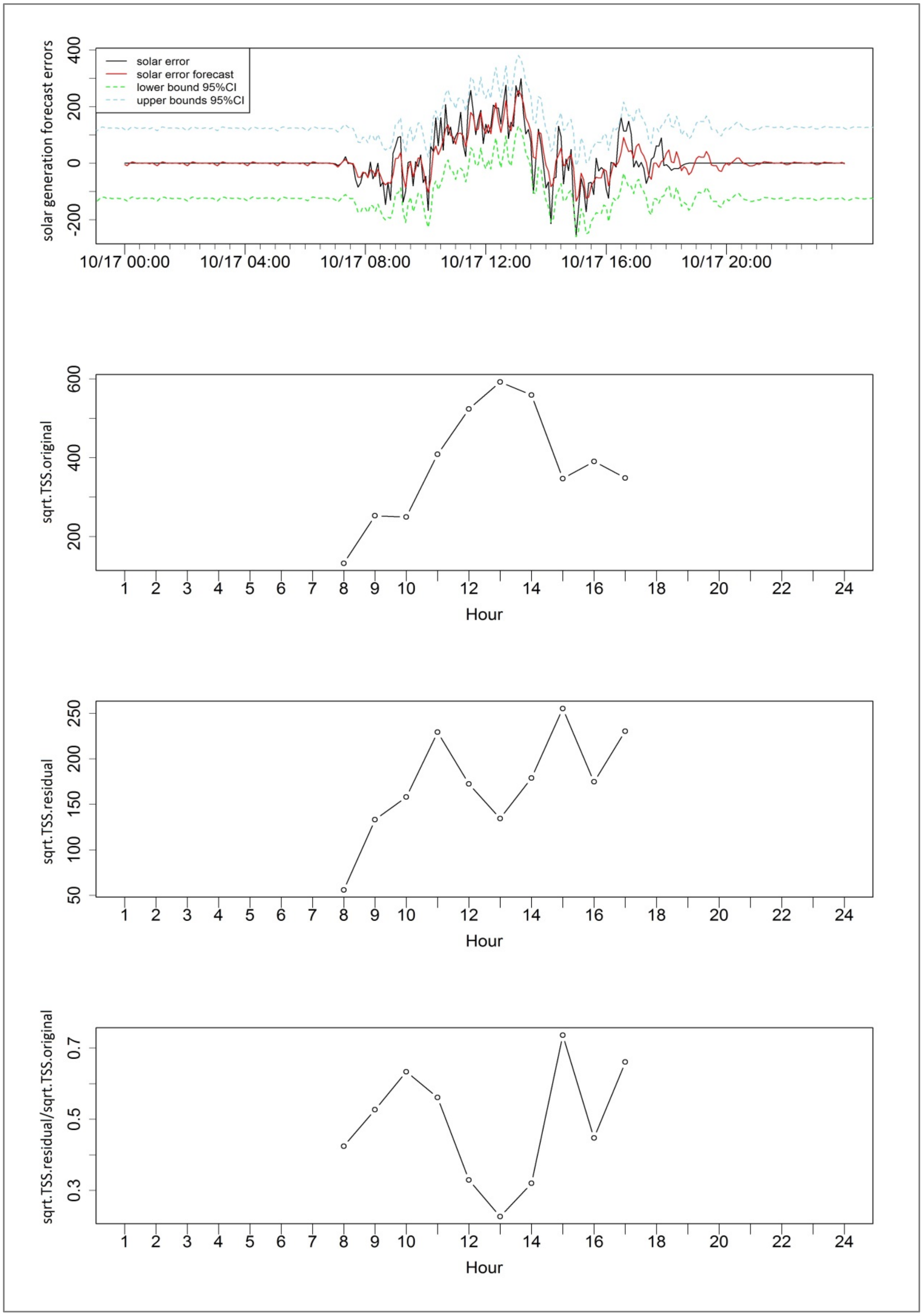

Figure 6. An example of solar generation forecast errors and its predictions, and the reduced uncertainty relative to the original uncertainty (see bottom panel).

The regression tree short-term forecasting approach also addresses the challenges in forecast error prediction and uncertainty reduction. The regress tree approach is meant to decompose the actual system solar and net load into three different components obtained from balancing authorities: (1) the first component refers to hourly, daily, and even longer term forecast, reflecting the system slow motion; (2) the second component is the estimate of forecast error that capture the fast motion of system movement in near term. They remove most of longer term period patterns and preserve relatively fast signals; and (3) the third component is the residual representing very fast motion that can be characterized as noises. The main idea is illustrated in Eq. (2), where the second and third components constitute the solar and net load forecast error shown in Eq. (1). Separating these components and estimating the solar and net load forecast error make it possible to reduce forecast errors and system uncertainties, resulting in many benefits for the power system planners and operators. To achieve this goal, badging decision trees [23], an ensemble method that builds multiple decision trees by repeatedly resampling training data with replacement and voting the trees for a consensus prediction, are used to effectively estimate the solar and net load forecast errors, which leaves the main uncertainties of solar and net load with the residuals.

Actual net load = load forecast + load forecast error – (renewable forecast + renewable forecast error)
= net load forecast + net load forecast error (1)

Actual solar/ net load = solar/ net load forecast (slow motion) + estimate of solar/ net load forecast error (fast motion) + residuals (very fast motion) *(2)*

For example,

a. For solar, on October 26:

Figure 7 (top) shows the comparison between the actual and the predicted forecast error of the solar. Figure 7 (bottom) shows the residual (the actual minus the predicted solar forecast error). Figure 8 shows hourly square root of the total sum square of predict and actual solar forecast error. Figure 9 shows solar hourly square of the total sum square of residual/actual forecast error with 5-min resolution. It shows that uncertainty in net load forecast errors can be reduced by 20~90%.

The standard deviation (STD) is reduced to 44.53% of that of the actual forecast error.

- STD_Actual = 195.9758
- STD_ Residuals = 87.2681
- Reduced =44.53%

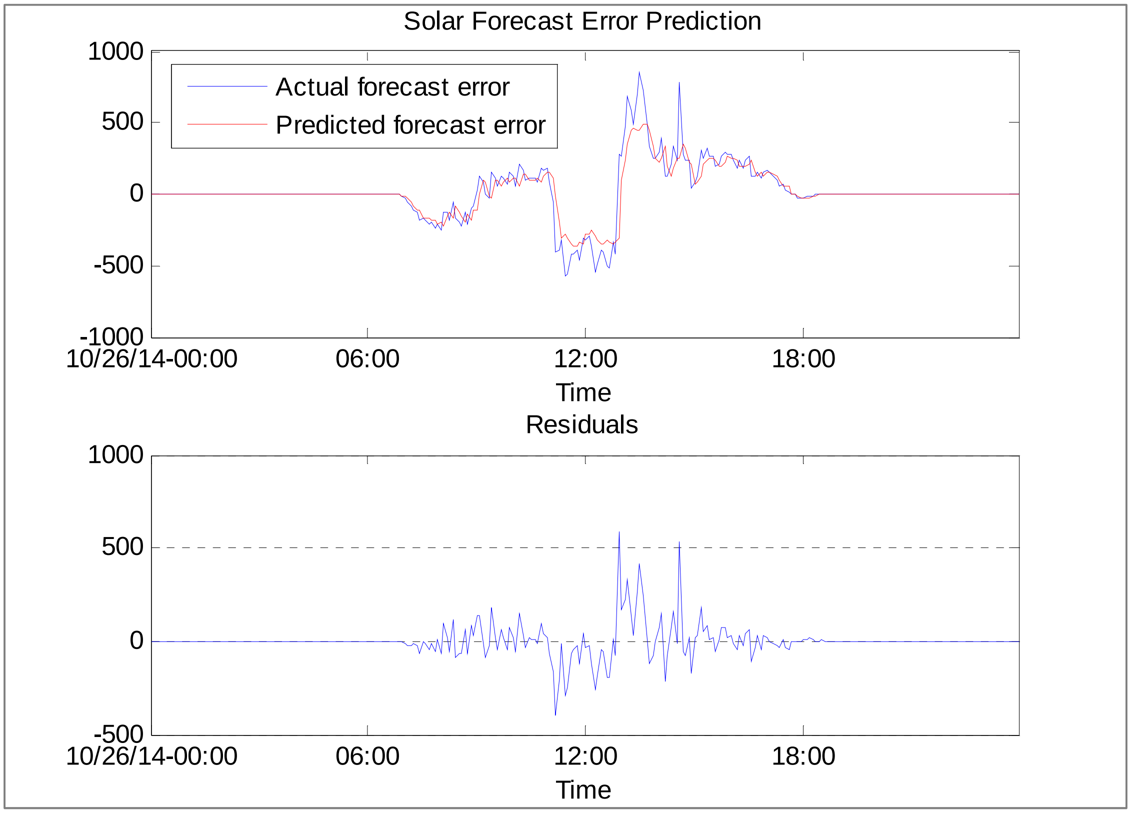

Figure 7. Solar forecast error prediction

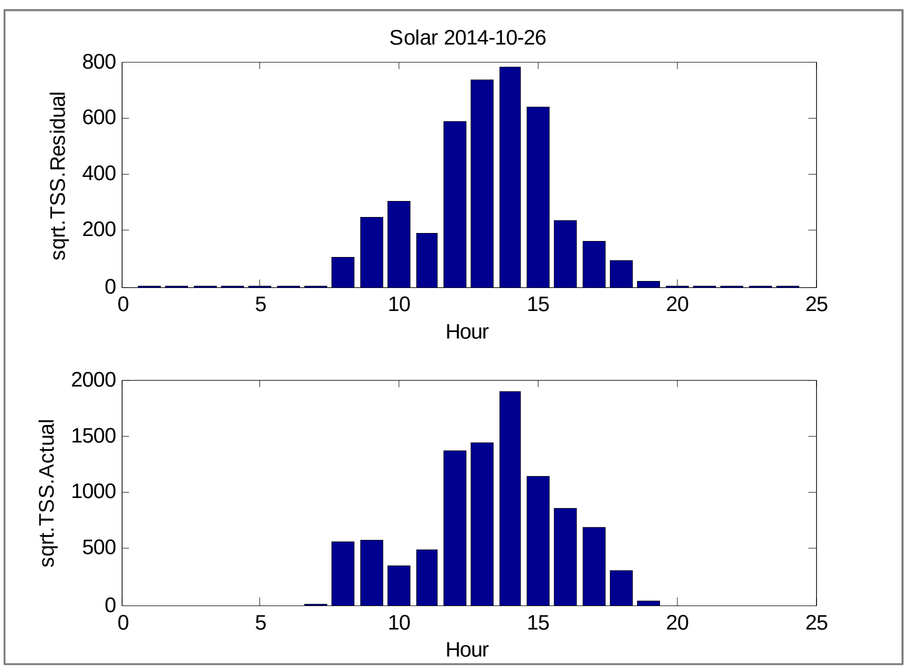

Figure 8. Solar hourly square of the total sum square of predict and actual forecast error.

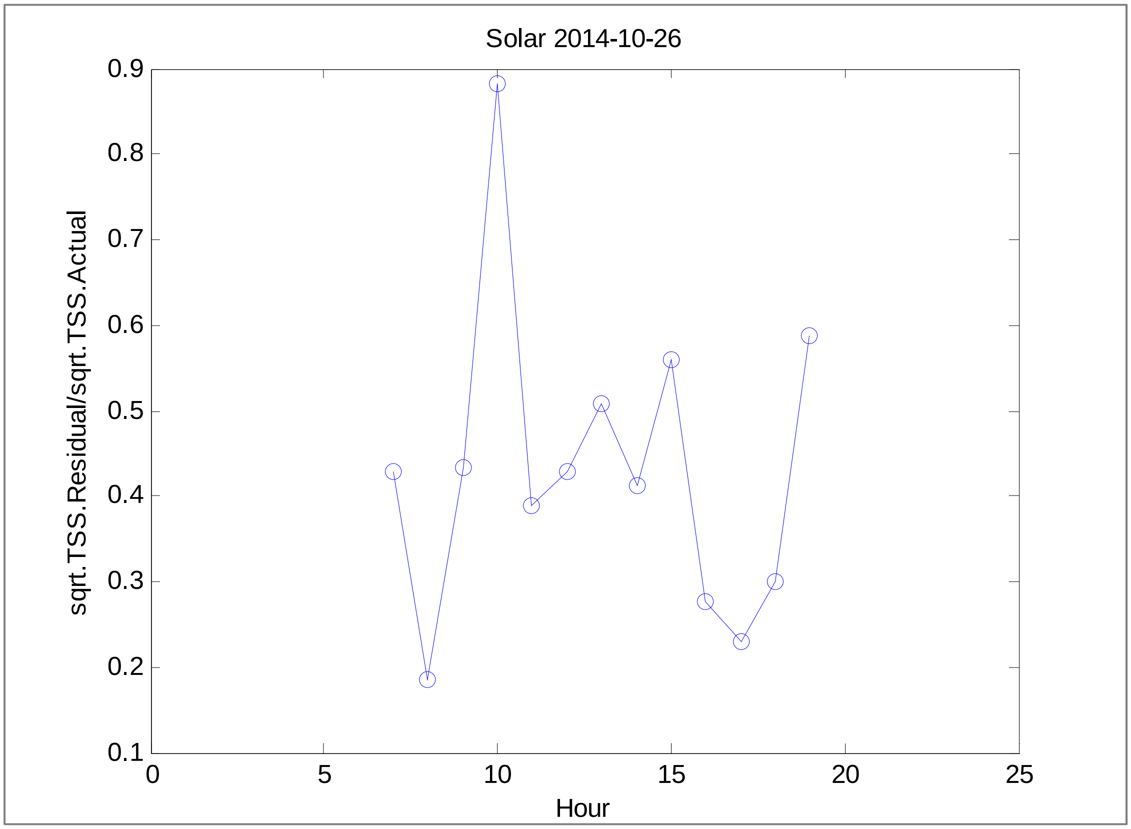

Figure 9. Solar hourly square of the total sum square of residual/actual forecast error.

A last component of Task 2 that was added by the DOE during the Go/NoGo discussions was a comparison of the RUT solar generation predictions and the probabilistic solar forecasts created by AWST during a period in 2013. This analysis showed that the use of the advanced probabilistic forecast provided by AWST allows a reduction in the size of the predicted confidence ranges during all conditions (morning and evening ramps and during the day time). Confidence range size reduction depends on the time of the day and look-ahead prediction interval, but on average reduction of the predicted range is about 12-31%. This means that Balancing Authorities (e.g. CAISO) can procure less balancing resources without compromising their reliability and control performance requirements. Thus, advanced probabilistic forecast can potentially reduce the energy prices and help better utilize limited system balancing resources.

Figure 10 and Figure 11 presents the balancing requirements calculated for CAISO from RUT area on 8/27/2013 at 8 a.m.. Figure 10 shows the results in a case when the deterministic solar forecast is used. Figure 11 presents the results when the advanced probabilistic solar forecast is used. At 8 a.m. there is a morning solar generation ramp; solar generation increased from 600 to 1200 MW (see Figure 12). The prediction results in numerical form are given in Table 7. It can be seen from this table that advanced probabilistic forecast created by AWST reduces the size of the predicted confidence ranges. For instance, for 5 min ahead interval the utilization of advanced forecast reduced the size of the 95% confidence range by 20.8%. Advanced forecasts are especially efficient for 5–30 minutes ahead intervals.

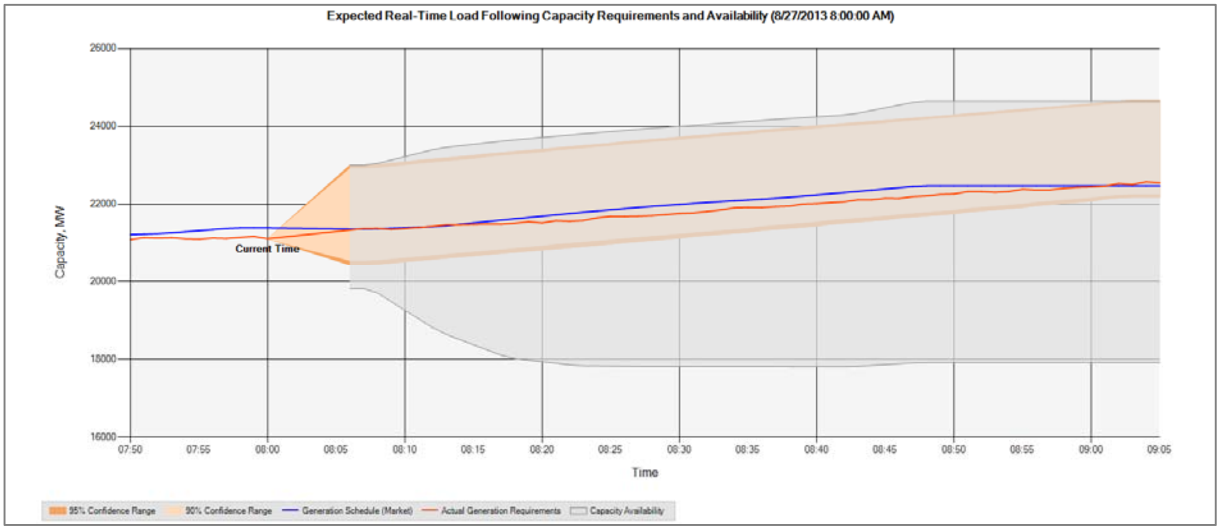

Figure 10. Balancing requirements on 8/27/2013 at 8 am: deterministic solar forecast.

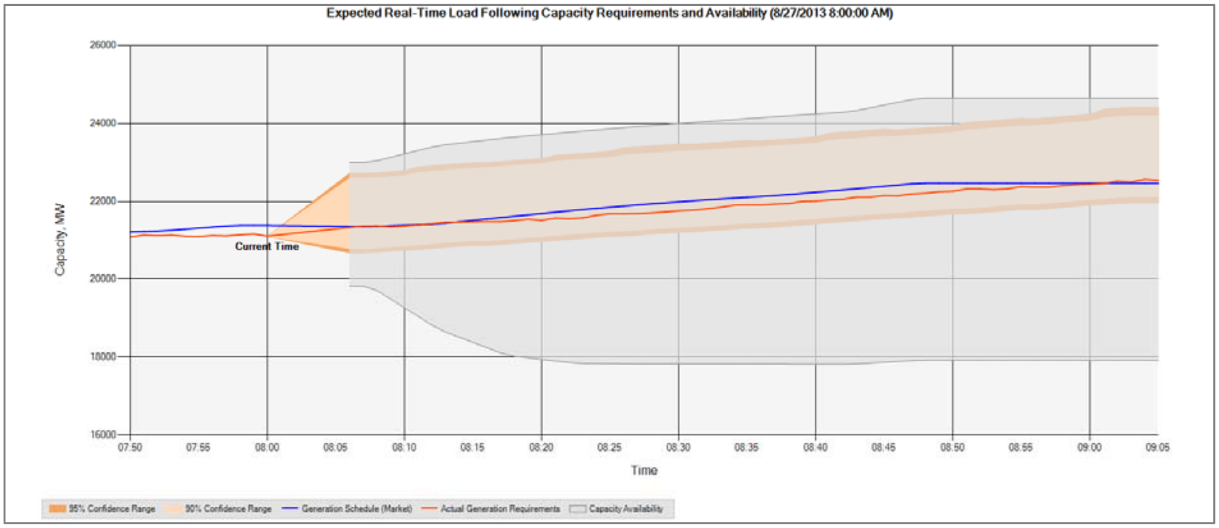

Figure 11. Balancing requirements on 8/27/2013 at 8 am: advanced probabilistic forecast.

Figure 12. Solar generation on 8/27/2013 at 8 am.

Table 7. Balancing requirements on 8/27/2013 at 8 am comparison.

Look-ahead interval (minute)	Deterministic			Probabilistic			Range Reduction, %
	Up	Down	Range	Up	Down	Range	
5	23013.67	20444.35	2569.32	22730.15	20696.45	2033.692	**20.8**
10	23176.55	20597.08	2579.47	22928.96	20816.91	2112.047	**18.1**
15	23337.67	20750.1	2587.57	23037.91	20914.74	2123.167	**17.9**
20	23490.95	20895.7	2595.25	23221.2	21044.01	2177.192	**16.1**
25	23651.78	21053.86	2597.93	23416.77	21152.07	2264.701	**12.8**
30	23798.89	21212.94	2585.95	23508.64	21257.82	2250.824	**13.0**
35	23947.68	21367.39	2580.29	23592.18	21361.45	2230.725	**13.5**
40	24087.66	21526.85	2560.82	23793.93	21496.36	2297.56	**10.3**
45	24222.45	21684.38	2538.06	23872.24	21618.09	2254.156	**11.2**
50	24366.11	21840.59	2525.53	24065.56	21725.84	2339.727	**7.4**
55	24507.33	22004.19	2503.14	24165.48	21834.65	2330.83	**6.9**
60	24652.39	22172.05	2480.34	24403.09	21963.18	2439.916	**1.6**

The main conclusion of this explained in more detail in the Task 2-c report is that the simulations confirmed the effectiveness of the advanced probabilistic solar generation forecast. The use of the advanced probabilistic forecasts allows a reduction in the size of the predicted confidence ranges during all conditions (morning and evening ramps and during the day time). Confidence range size reduction averaged 12-31%.

3.1.3. Task 3: Active Integration of uncertainty and variability information into power system operations

The body of work associated with Task 3 set the stage for the experiments to be run in Task 5. All efforts as part of Task 3 were successful and met the target milestones. The effort focused on the integration methodology between the RUT output and the Siemens market applications in an offline environment. The results of the integration testing process were successful and warranted no modifications to initial integration approach.

Once the RUT output was integrated with the CAISO market applications, there were changes made in the SCUC and SCDD optimization engine using Mixed Integer Programming (MIP) technology. These changes created the mechanism to use the system flexible ramping requirements from the RUT interface instead of internal and deterministic calculations inherent in the SCUC and SCDD. Using the RUT output within the market application optimization engine, flexible ramping constraints are included in the whole optimization formulation without any further MIP engine modification. Figure 13 demonstrates the processing with current and new approaches of flexible ramping requirement determination.

The project team reviewed the newly available data categories and the setup of optimization engine and concluded that the method below is the fastest and most accurate way to safeguard the energy balancing scheme from the uncertainty arising from variable energy PV sources.

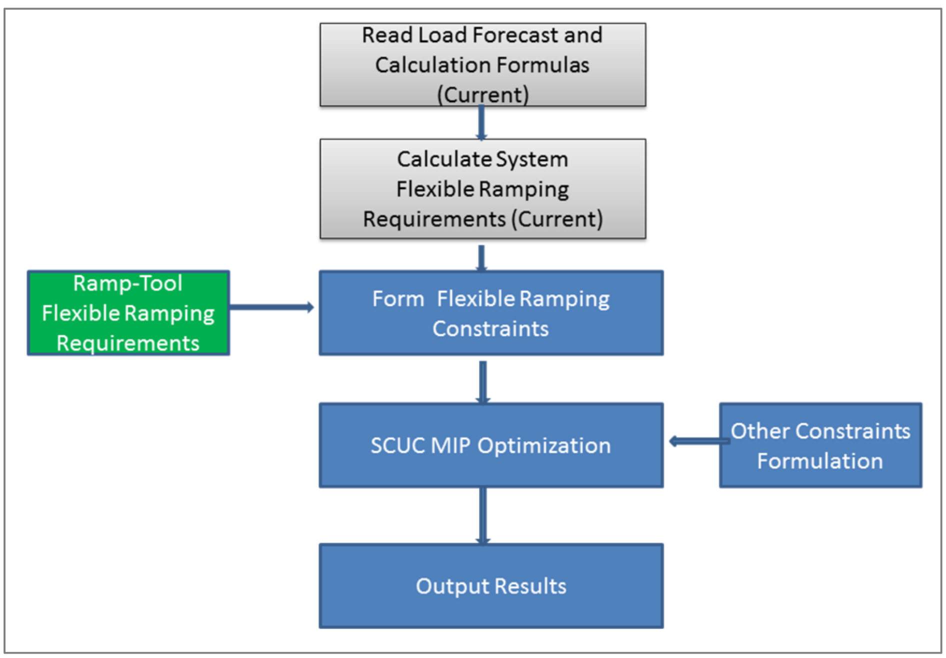

Figure 13. MIP Engine Working Flowchart

Several data formatting and data conversions were necessary. Table 8 and Table 9 define the format of flexible ramping requirement application output tables. Due to different needs in different market runs, the “IntervalID” in both tables represents 60 minutes in Day Ahead Market, 15 minutes and 5 minutes data sets in Real Time Market. The fifteen minute data is meant for Real Time Pre-Dispatch (RTPD 5 – 18 interval modes - the 7 interval run is for Hour Ahead Scheduling Process and 18 interval run is for Short Term Unit Commitment run). This is illustrated in Table 10.

Table 8 . Capacity Requirements Table

Column Name	Column Type	Unique	Definition
TimeStamp	TimeStamp	YES	Timestamp indicates beginning of the first interval
Confidence	Number (3,0)		Confidence level. Can be from 0 to 100%
IntervalID	Number(3,0)		Look-ahead interval ID
FRUP	Number	No	Upward capacity requirements for a specific look-ahead interval
FRDN	Number	No	Downward capacity requirements for a specific look-ahead interval
GENRQ	Number	No	Generation Requirements (Load – Solar – Wind + Interchange) for a specific look-ahead interval as a reference basis from ramp-tool

Combination of Timestamp, Confidence and Interval ID should be unique.
FRUP-GENRQ = Flex Ramp upward requirements over generation requirement
GENRQ-FRDN = Flex Ramp downward requirements over generation requirement

Table 9. Ramping Requirements Table

Column name	Column Type	Unique	Definition
TimeStamp	TimeStamp	YES	Timestamp indicates beginning of the first interval
Confidence	Number (3,0)		Confidence level. Can be from 0 to 100%
IntervalID	Number(3,0)		Look-ahead interval ID
RampDuration	Number(3,0)		Ramp duration requirement in minutes.
RampRateUp	Number	No	Upward ramp rate requirements for a specific look-ahead interval in MW/min
RampRateDn	Number	No	Downward ramp rate requirements for a specific look-ahead interval in MW/min

The combination of Timestamp, Confidence, Interval ID and Ramp Duration should be unique.

Table 10. Flex Ramp Requirement Basis for Markets

Market Type for Optimization	Interval Size basis for Table 9 and Table 10 datasets from RUT	Confidence Range of Flex Ramp data Set from Ramp-Tool	Default Flex Ramp allocation – configurable in Markets
Day Ahead Market (DAM)	60 minutes	95%	60 % of Flex Ramp requirements protected in DAM
Real Time Pre Dispatch (RTPD)	15 minutes	95%	60% of difference between RTPD current requirement and DAM protected earlier requirement
Real Time Dispatch (RTD)	5 minutes	95%	100% of difference between current RTD requirement and (DAM+RTPD) protected requirement

Because the data format in the first two tables (Table 8 and Table 9) are different from that used in current CAISO market applications and the single SCUC MIP engine was called by all DA and real time applications, some necessary data conversion were made in either the market application or workflow script. First, each record represented its own timestamp by combining the timestamp of first interval and interval ID in each different market run. Since the time granularity in RTPD run is 15 minutes and capacity requirement data is for every 5 minutes, the average value of every 3 records within each 15 minutes was taken as the capacity requirement if there was only 5 minute data available. In the end, the difference between the upward/downward capacity requirement and generation requirement forecast was considered as the upward/downward flexible ramping requirements respectively. Also there could be multiple sets of records for different confidence level in the tables. Hence the predetermined confidence level had to be provided before the data conversion.

Through Table 9, the system flexible ramping requirement can also be calculated by multiplying the ramp rate with associated ramp duration. These sets of values are available and may indicate any high degree of deviation between the average value and an instantaneous value inside the interval. Table 9 data was not used since the selection of the 95% confidence range data set already covers a reasonable amount of uncertainty to start with, and is considered a reasonable compromise between economics and reliability-readiness. Table 9 data will be made available for analysis and obtaining more insight in to the quantifications of further granular view of uncertainty, as well as, exploring the sub-optimality versus roles between the Load Frequency Control of EMS- Automatic Generation Control (AGC) and Real Time Dispatch of Market.

During this project, flexible ramping is a system level constraint on a per time-interval basis and protected for as reserve in the multi-interval security constrained dynamic dispatch during Day Ahead and Real Time Market runs. In the future, it is the project teams understanding that

CAISO might convert this system requirement to be a bid-in-commodity of Ancillary Services (AS) similar to that of Regulation, Spin and Non-Spin products already included in the market [24]. When new variables are defined for ramping up/down capacity in the optimization formulation, they are binding with energy commodity. This way there is no need to introduce bids for the new commodity types for ramping up/down capacity, which will minimize the changes to DB schema, market Apps and downstream process. The variable lower limit is 0 MW while the upper limit is bound by the maximum quantity that can be awarded within the time domain for flex ramp commodity, under resource operating ramp rate for energy. Here the operating ramp rate is either the bid in static ramp rate from energy bid or the minimum ramp rate from the bid-in ramp rate curve for dynamic ramping resources.

As part of this effort, logic was developed considering several different scenarios in RTN whereby no flexible ramping capacity should be awarded for that time interval:

- energy bid is created through no-bid matrix proxy;
- the bid has OOS schedule;
- the resource has "F" (Fixed) energy bid operating mode but doesn't have price curve;

3.1.4. Task 4: Provide DOE and public accessible data created from project

This task collects and makes available to the DOE for public consumption data that was generated in this project. Data will be shared granted it is allowable given the potential proprietary or sensitive nature of the data. When applicable, data will be masked or normalized to protect confidential or sensitive data.

All appropriate data will be shared which meets the milestone target for Task 4.

3.1.5. Task 5: Active integration and quantification of uncertainty and variability information into power system operations

The objective of this task is to run the Siemens SCUC and SCDD procedures used by CAISO with output from the RUT. The Task goal was to quantify the cost of uncertainty for the system operator and to prevent approximately 75% of the real-time market price spikes. While the milestone target of quantifying the cost of uncertainty was not met, other meaningful and industry relevant work was achieved that shows an improvement in real-time control performance. The runs were performed offline by using stand-alone applications and datasets provided by the CAISO. Actual integration of these tools could happen at CAISO as a separate project and this body of work will dramatically simplify this integration by providing demonstrated connectivity between the relevant tools and detailed specifications. While avoiding price spikes could not be demonstrated because there was no discernable correlation between the available solar generation data and pricing data, reliability issues could be traced to solar generation variability. By approaching the experiments with the goal of achieving demonstrably better system reliability, the Task efforts were successful. The following describes the experiment configuration and results that show success in improving system reliability and the avoidance of related price spikes.

The experiment design utilized Siemens market application runs and included three cases: 1) system reliability in CAISO when the system dispatched in a “business-as-usual” case, 2) system reliability in CAISO when the uncertainty characteristics are incorporated into unit commitment and economic dispatch procedures, and 3) system reliability in CAISO when the uncertainty is reduced by using advanced forecasting algorithms and the RUT output. The three cases allow for a resulting analysis of the differences of system reliability during the standard CAISO operations (the business-as-usual case) and the quantifiable reliability benefits that result from the reduced uncertainty from the other cases.

The following describes the steps taken to set up and perform the experiments. Eight cases were selected on dates that showed significant movement of solar generation on the CAISO system. Production cases were retrieved spanning two to four hours per date. Four cases of Real Time Pre-Dispatch (RTPD 15 minute runs) and twelve cases of Real-Time Dispatch (RTD 5 minute runs) per hour were retrieved and loaded into the offline Siemens/CAISO market applications. These cases were reviewed by the project team with significant input from CAISO about which dates were of the most interest and for which the analysis would be most valuable. The two target dates that were selected by CAISO and the project team were October 15, 2014 and October 30, 2014. These dates offered significant movement of solar generation on the CAISO system as well as reliability concerns that were monitored by CAISO.

The appropriate market software versions that were actually deployed at CAISO during October 2014 dates were selected based on the case time stamps. These software versions excluded input from the advanced probabilistic forecasts, information from RUT, and other advancements made to the market applications since the case dates. This created an environment that accurately represented the market application's logic and therefore provide the most accurate business-as-usual case.

Before market applications runs could be performed, necessary interface format modifications were made to incorporate the RUT output into the market applications. Scripts were developed to read the RUT data as well as to smooth the data over multiple intervals of each real-time market dispatch to contain any price impact (avoidance of spikes) at the binding interval. The activation of flex ramp down constraints (in addition to existing flex ramp up constraints) and validation of the same in the market applications were made as necessary to perform the experiments.

After configuring and establishing the necessary data flows, market application runs were performed for both dates for the business-as-usual case and re-runs were performed with the projects related software modifications, RUT input, and probabilistic forecasts. Salient results were collected and analyzed by the project team. The efforts were performed before the runs, investigation phase of project. After the runs, scripts and database queries were made to select the data to be captured from the market application runs and calculation were made to determine the amount of used and unused flex ramp capacity to assist analysis for any given case.

The market application improvements further established the basis of results for achieving the desirable aspects in both energy pricing and reliability topics. For example, in 2014 only the Flex Ramp Up constraint was enabled to eliminate high price spikes in CAISO market application. Additionally, the loss of renewable energy was more a concern in 2014 perhaps owing to lower penetration levels. As the penetration levels increased, Siemens enabled the Flex Ramp down requirements and constraints to cover over generation aspects in the Look Ahead Security Constrained Dynamic Dispatch of Real Time Market (RTPD and RTD) in addition to covering the Flex Ramp Up requirements and constraints. Further, the smoothing of Flex Ramp up/down requirements occurred for the multi-interval dispatch to avoid price spikes for the binding interval for energy prices. By making use of the improvements in forecast and ramp requirement calculation we see new improved dispatch results of flex ramp allocation to relevant generators. The resulting runs also allow for one to calculate the new flex ramp capacity allocated, which is an improvement to current capabilities, and assess the unused capacity to understand better the range of used, as well as estimating the further and still available –but not locked, flex ramp capacities.

Case 1 focuses on the October 30, 2014 period in which CAISO documented reliability impacts due to solar energy variations. Evidence is seen in Figure 14 that show the CAISO load, net load, and wind generation and solar generation at 10 a.m. The plot shows a drop of approximately -400 MW in solar generation for a 30 minute period before again increasing. For the same period of time, Figure 15 shows a high negative value of -400 MW, referring to the under generation situation that was observed. During the same period of time, Figure 16 shows a system frequency decrease of -0.06 Hz.

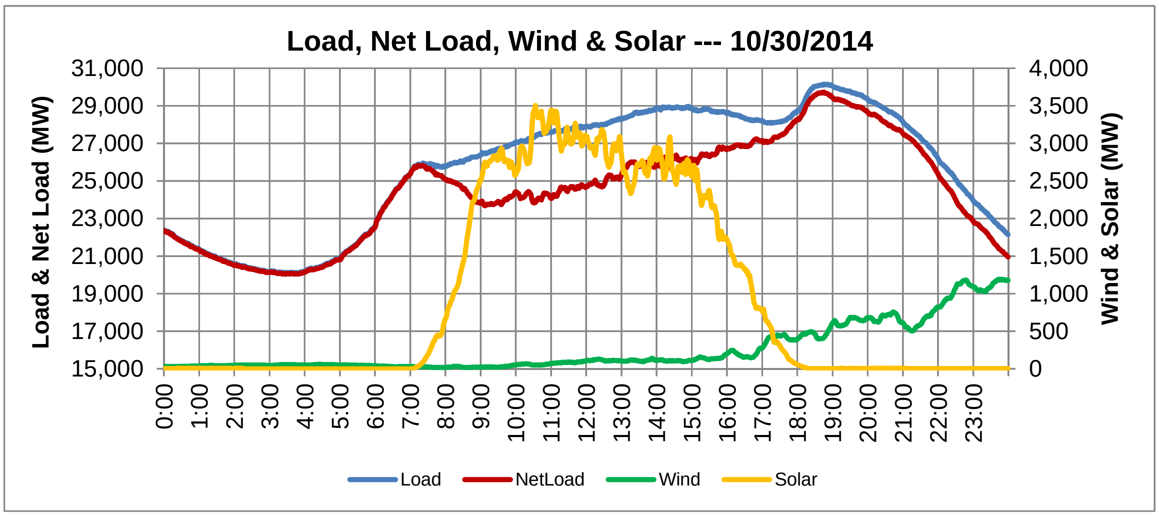

Figure 14. Load and Solar Energy Plot of October 30, 2014

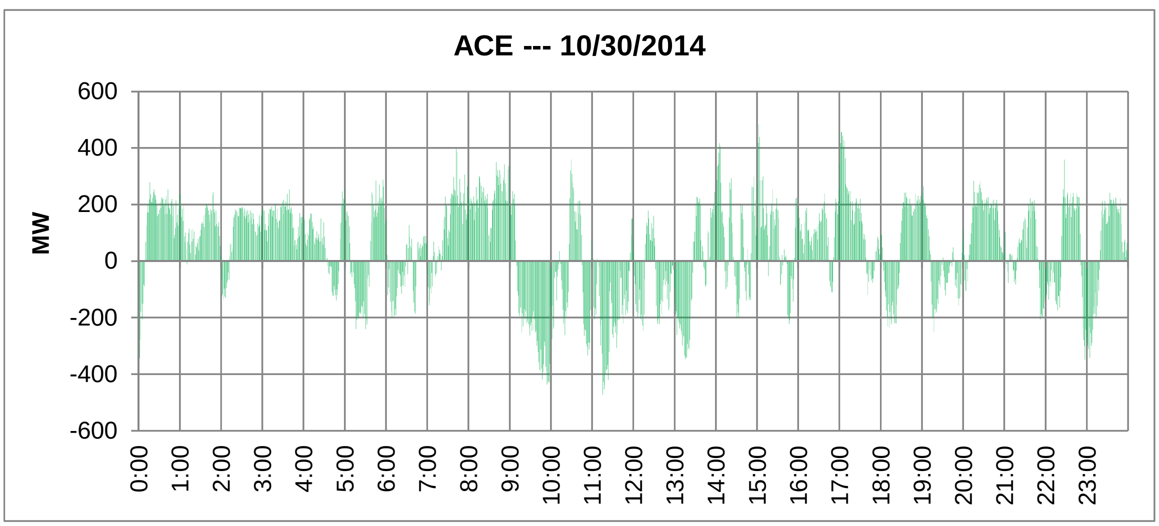

Figure 15. Area Control Error (ACE) of October 30, 2014.

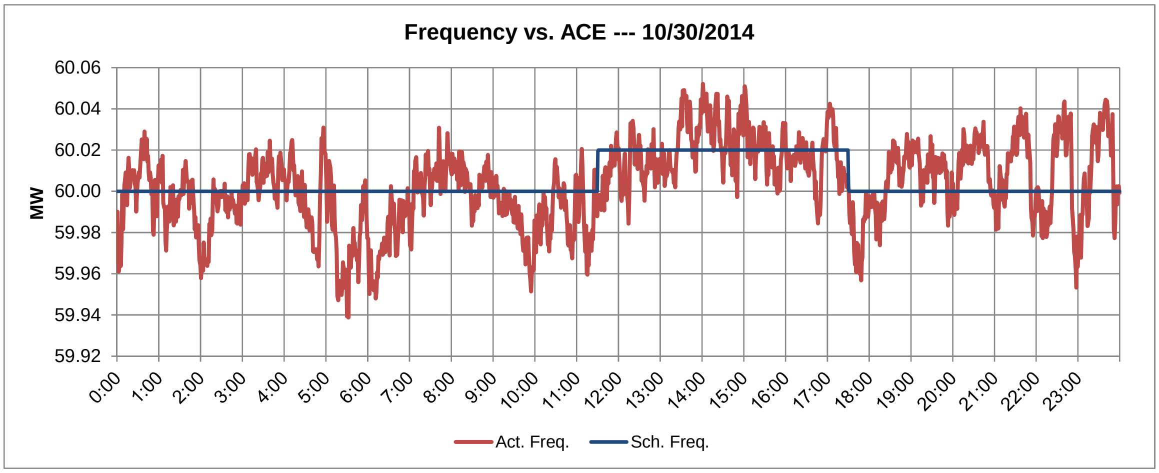

Figure 16. Scheduled and actual frequency for October 30, 2014.

These factors culminate in very high hourly CPS1 violations and one minute CPS 1 violations as shown in Figure 17 and Figure 18 respectively. Interestingly, the energy prices in the real-time market remain relatively flat and behaved normally behaved normally because the solar deviations were not captured at least 7.5 minutes before the RTD dispatch interval. There was no ramping insufficiency for energy dispatch and prices were not impacted by the decrease in solar generation or the system reliability issues (Figure 19).

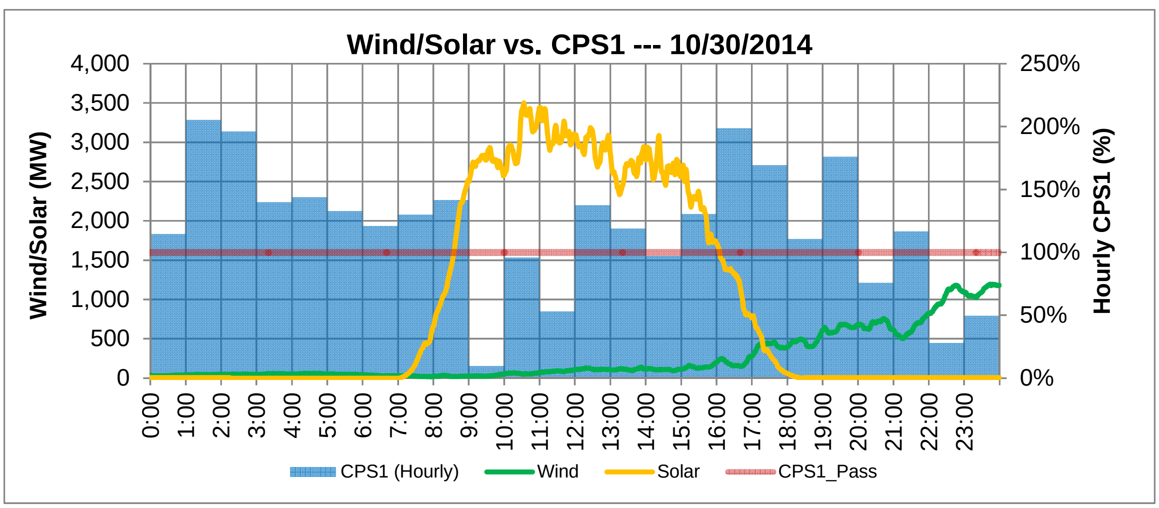

Figure 17. Hourly CPS1 reliability violation score with aggregate wind and solar generation for October 30, 2014.

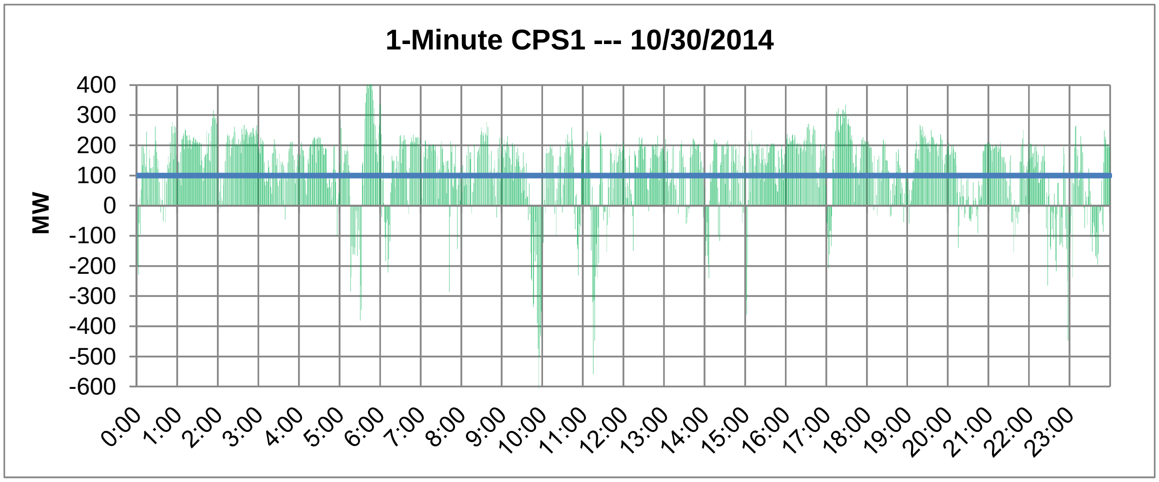

Figure 18. One minute CPS1 reliability violation score on October 30, 2014.

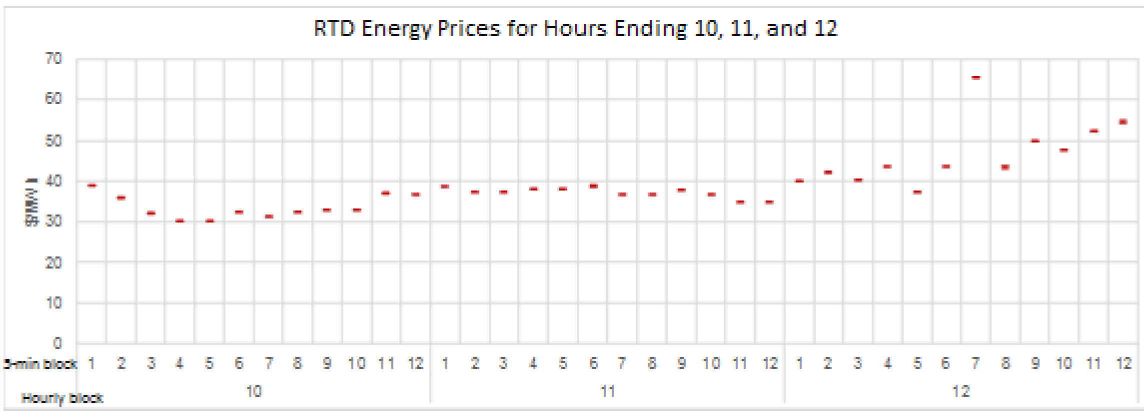

Figure 19. Real-time dispatch energy prices on October 30, 2014.

The Market Requirement Output Comparison (Flex Ramp Up) in Table 11 provides original run and experimental run including Flex Ramp Up cleared values of RTD. The experimental runs show higher amounts of flex ramp up requirements than the cleared values established in the original run. The unused flex ramp capacity (not locked in) is also established at a higher level. These higher amounts are also a result from the use of more resources qualified for flex ramp to meet a higher requirement. Increasing the availability of more resources was established by removing restrictions between RTPD flex ramp requirements (less accurate due to older deterministic forecast) and restricting the RTD (new probabilistic forecast) to use of only a portion of what was established by RTPD. Instead, the emphasis was placed on more accurate flex ramp up requirements established by RUT in 5 minute granularity and 5 minute periodicity and removing the restriction placed over RTPD values (which are more stringent for commitment and regulation awards purposes).

As RTD executes every 5 minutes, each execution revises the flex ramp requirement with the most recent forecast information thereby updating the flex ramp requirements in real time as opposed to a delay that would be expected in the RPTD. The cascading effect of utilizing the most current predictions provides a safeguard of setting aside ramp in the range of 200 – 600 MW in subsequent intervals. This additional flexibility was not seen in the Original Case run (Table 11) where frequency and reliability violations were present. It should be noted that such flex ramp capacity if bid into the regulation market, may be available for dispatch through AGC. Until flex ramp becomes an Ancillary Service (AS) product, the use of this capacity by AGC could be fulfilled. Flex Ramp as an AS product would require a market structure change and is under review at CAISO.

Table 11. Market requirement output comparison (Flex Ramp Up) from the 10 a.m. market run October 30, 2014.

Interval	Time Interval	Original Case	Experimental Case
		Flex Requirement	Flex Requirement
1	10:00	0	0.0
2	10:05	50	220.2
3	10:10	100	313.2
4	10:15	150	548.0
5	10:20	200	654.0
6	10:25	200	305.3
7	10:30	200	232.3
8	10:35	200	400.1
9	10:40	200	648.0
10	10:45	200	448.9

Note that interval 5 allocated up to 654 MW (new method) and allocates a high amount of flex ramp up quantity (454 MW higher than the original run). Table 12 shows that in the experimental run the energy cleared is the same as the original run, and the price differences between the original and experimental run for such high allocation of flex ramp up quantity does not impact the prices in any way. These results confirm, the solar variability resulted -400 MW ACE (solar drop and Area Control Error showing high under generation), and the new method allocates sufficient flex ramp quantities to handle this reliability issue without much impact on energy prices. This result confirms the Market Dispatch can handle the pricing and reliability aspects satisfactorily. However, the resulting flex ramp quantities need to be used by AGC (as future work) as specified in the next subsection. Modification of AGC is not in the scope of this project. Real Time dispatch has made sufficient provisions and ample ramp capacity for AGC to take up further.

Table 12. Market Requirement Output Comparison (Energy) and Price, October 30, 2014.

Interval	Time Interval	Original Case		Experimental Case	
		Energy Cleared	Shadow Price	Energy Cleared	Shadow Price
1	10:00	28269.5	38.8	28269.4	38.8
2	10:05	28331.9	37.4	28331.8	37.4
3	10:10	28462.8	37.6	28462.8	37.2
4	10:15	28519.9	36.7	28522.5	40.5
5	10:20	28568.9	38.8	28567.0	45.0
6	10:25	28613.4	38.8	28611.5	38.7
7	10:30	28662.0	36.7	28660.5	36.7
8	10:35	28706.7	37.8	28704.5	37.8
9	10:40	28753.1	37.0	28750.6	37.8

10	10:45	28804.6	38.2	28802.3	37.8

The experiments also created an understanding of the hand-off between the Real-Time Market and AGC of the EMS. The probabilistic forecast as well as assessment of variability (flexible ramping) requirements, enables us to ensure adequate ramping is available for regulation of frequency and scheduled interchange, when the real time operation faces renewable energy variability.

3.1.6. Task 6: Transmission and distribution system uncertainty prediction tool

This task improved a tool already under development by PNNL called the Transmission Uncertainty Tool (TUT) and introduced the TUT to system operation engineers through an online webinar. The TUT is a prototype software tool which can analyze and predict the impact of solar generation in addition to other sources of uncertainty and variability on the transmission and distribution systems including congestion, voltage reductions, and reactive power margin for up to five hours ahead of time.

The approach is based on a geographically distributed multi-source uncertainty model, probability-based contingency simulation, linearized power flow model, and Monte Carlo method. This probabilistic tool showed to improve situation awareness and reliability by predicting potential violations of the transmission/distribution system limits and associated risks on critical lines/paths in the system, for all credible contingencies, as well as the expected time to violations.

In this project, a probabilistic approach is applied where the probability of transmission limit violations are evaluated. Random factors contributing to this possible violation include random unpredicted variations of wind, solar generation and system load. Similar to a deterministic approach the analysis was conducted for a specified set of contingencies. The probability distribution of transmission flows can be obtained by multiple Monte Carlo runs, where the power mismatches caused by forecasting errors and variability in different parts of the system are simulated repeatedly by an advanced statistical module described in a previous section. Resulting power flow variations in the analyzed transmission paths are obtained with the help of a linearized incremental power flow model and power transfer distribution factor (PTDF) as described below.

Step 1. Build linearized power flow model

The power flow linearized incremental model is used in this project to evaluate the incremental impacts of wind, solar, and load variability and uncertainty on power transfers in the analyzed paths. The model allows simplifying and speeding up multi-variant computations needed to implement a probabilistic assessment of power transfer and voltage variability using the Monte Carlo method. The incremental analysis is conducted around selected base cases and contingencies produced using the full AC system model. The procedure used to create the incremental model using Power World Simulator software is presented and illustrated in this section using an example of the WECC system model.

The full WECC system model used in the study consists of more than 19000 buses, 19000 branches, and 3700 generators. A total of 21 zones are defined in the model.

The incremental impact analysis is used to find a relationship between variations of the total zonal active power imbalance and related active power-flow variations in selected transmission interfaces.

The process that we suggest is based on the Monte Carlo (MC) method. The MC method is frequently used in probabilistic power flow analyses. It requires hundred and thousands power flow runs. An AC power flow model can make the computational time unacceptable for practical purposes. A traditional approach to resolve this problem uses DC or linearized power flow formulations. The linearization approach was selected for this study. Its accuracy is usually considered as sufficient (for the active power flow analyses) comparing to the uncertainty of input parameters.

The active power-flow variation in the interface between the zones *i* and *j* can be calculated as:

$$\Delta P_{ij} = \sum_{n=1}^{N} PTDF_n^{ij} \Delta P_n \qquad (1)$$

where N = the number of zones in the system,

ΔP_n = variation of total active power generation in zone n, and

$PTDF_n^{ij} = \frac{\Delta P_{ij}}{\Delta P_n}$ = a power transfer distribution factor reflecting the influence of generation in zone n on the power flow in the interface i-j.

Step 2. Solve power flow for all expected scenarios

Scenarios simulated by an advanced statistical model are used at this step. Expected load, wind and solar forecast errors for a specific scenario are assigned to all zones in the system. Then the errors are added to the deterministic load, solar and wind generation values and zonal power flow solution is calculated using PTDF based model for all corresponding scenarios (Monte-Carlo runs). The same process is repeated for all simulated scenarios and all future dispatch intervals (Figure 20).

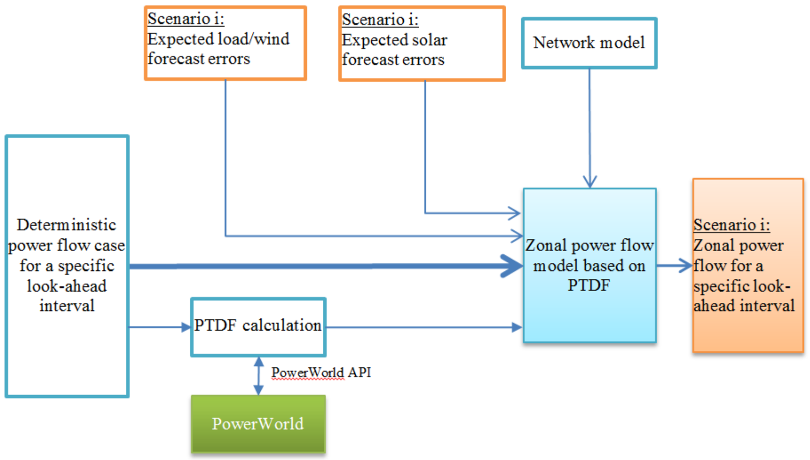

Figure 20. Probabilistic power flow solution for a specific look-ahead interval..

Step 3. Calculate expected power flow and voltage distributions

At this step the PDF of power flow distribution through transmission lines and critical transmission interfaces are calculated. According to [25]: "The distribution function *D(x)*, also called the cumulative distribution function (CDF) or cumulative frequency function, describes the probability that a random variable *X* takes on a value less than or equal to a number *x*. The distribution function is sometimes also denoted *F(x)*. The distribution function is therefore related to a continuous probability density function (PDF) *P(x)* by

$$D(x) = P(X \leq x) = \int_{-\infty}^{x} P(\xi)\, d\xi$$

Similarly, the distribution function is related to a discrete probability *P(x)* by

$$D(x) = P(X \leq x) = \sum P(x)$$

Step 4. Contingencies analysis

Repeat steps 1 to 3 for each contingency from the contingencies list. If the actual statistical information on the contingencies is not available, the probability of each contingency can be derived from the NERC Generating Availability Data System (GADS)[5] and Transmission Availability Data System (TADS)[6]. These databases contain generic information on forced outage rates for different elements of the transmission system by type and by climate conditions.

Step 5. Combined PDF for the base case and all contingencies.

At this step the combined PDFs that include PDF calculated for the base case and for each contingency are calculated (Figure 21). To calculate the PDF and CDF for the sum of the independent random variable a convolution method is used. Assume that the PDFs are

[5] http://www.nerc.com/pa/RAPA/gads/Pages/default.aspx

[6] http://www.nerc.com/pa/RAPA/tads/Pages/default.aspx

$P_1(x)$ and $P_2(y)$. The convolution of the two PDFs is $P_s(z)$ which can be computed as follows using equation:

$$P_s(z = x + y) = P_1(x) * P_2(y)$$

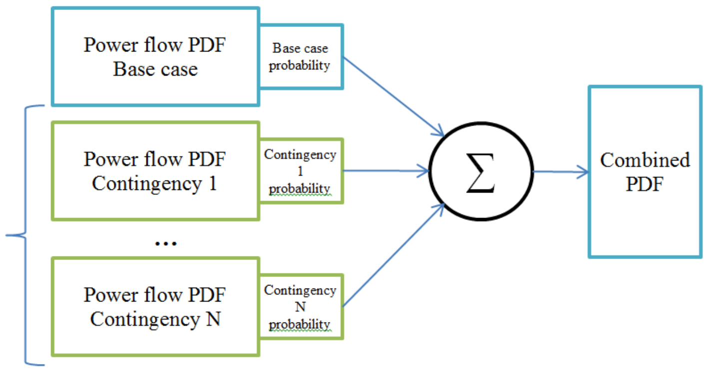

Figure 21. Computation of the combined PDF.

Step 6. Probability of Violation of Transmission Limits.

The user can specify maximum acceptable probabilities of violating transmission limits caused by random variations of uncertain parameters around their forecasts in the base case, p_b^t, and under contingency conditions, p_c^t. In case of limits induced by stability conditions, this probability should be zero. This figure shows a distribution $PDF\left(P_{ij}^c\right)$ of possible values of i-j power flow in the most limiting contingency. The probability of having a power flow above the limit TC_{ij}, corresponding to the most limiting contingency, where $P_{ij} = \max P_{ij}^c$, is

$$p = \int_{TC_{ij} \le \tau < \infty} PDF(\tau) d\tau$$

This probability of having the flow above the thermal limit in this contingency should be kept below a user specified level, $p \le p_c^t$. If this probability exceeds p_c^t, the power flow in the base case P_{ij}^b should be additionally limited by adding a more restrictive limit TC_{ij}^b to be enforced during system operation, as shown in Figure 22.

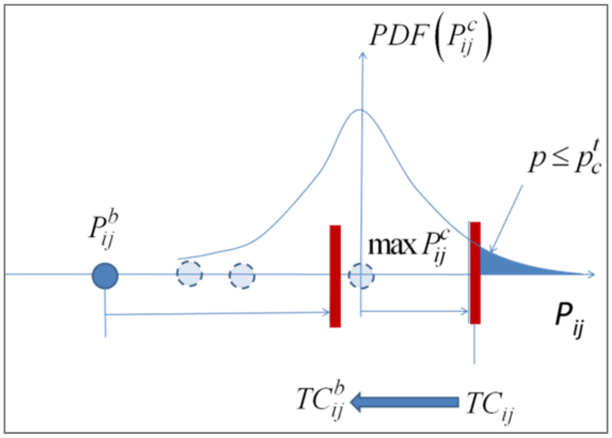

Figure 22. Probabilistic Limits for Base Case Conditions and Contingencies

Results of the PTDFs calculation for all WECC zones are shown in Figure 23.

Number	InterfaceName	InterfaceMW_Flow	NEW MEXICO	EL PASO	ARIZONA	NEVADA	MEXICO-CFE	IMPERIALCA	SANDIEGO	SOCALIF	LADWP	PG AND E	NORTHWEST	BC_HYDRO	FORTISBC	ALBERTA	IDAHO	MONTANA	WAPA UM_	SIERRA	PACE	PSCOLORADO	WAPA RM_
1	ALBERTA - BRITISH COLUMBIA	-400.528	-7.258	-7.166	-8.246	-7.234	-7.219	-7.192	-7.191	-7.669	-7.309	-8.42	-8.933	-7.575	-7.141	94.165	-7.236	-7.266	-7.118	-7.225	-7.538	-7.416	-7.403
2	ALBERTA - SASKATCHEWAN	0.101	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
76	ALTURAS PROJECT	96.647	-1.184	-1.247	-1.395	-1.713	-1.107	-0.974	-1.113	-0.868	-1.221	0.709	1.963	1.6	1.468	1.596	0.023	1.056	1.055	-13.506	-0.939	-0.75	-0.595
33	BONANZA WEST	494.907	1.864	1.232	-0.441	-1.566	-0.924	-1.043	-0.907	-1.365	-6.274	-2.183	-2.49	-2.063	-1.909	-2.063	-3.477	-0.547	-0.862	-3.478	-1.555	20.413	18.737
17	BORAH WEST	460.044	9.392	8.595	6.239	3.955	3.679	2.827	3.74	1.626	16.912	-7.246	-13.734	-11.199	-10.188	-11.093	-21.482	-2.727	-3.098	-6.207	35.692	21.567	20.34
19	BRIDGER WEST	1609.138	0.375	0.026	-1.206	-1.752	-1.484	-1.621	-1.465	-1.988	-2.246	-3.435	-3.876	-3.164	-2.891	-3.134	-6.786	0.777	-0.156	-3.955	18.172	14.378	14.607
55	BROWNLEE EAST	1156.144	-4.271	-4.159	-4.229	-3.729	-3.378	-3.173	-3.381	-3.086	-5.636	-1.12	6.711	5.633	5.214	5.692	15.869	4.032	3.946	-5.769	-8.292	-5.395	-4.918
81	CENTENNIAL	2032.329	-6.089	-6.81	-9.391	53.811	-8.411	-8.017	-8.402	-8.062	-0.269	-2.243	2.181	1.758	1.571	1.743	5.134	1.922	1.799	31.64	5.299	1.027	1.324
50	CHOLLA - PINNACLE PEAK	685.154	10.801	10.697	0.931	-2.183	-2.928	-2.72	-2.94	-2.454	-0.533	-1.684	-0.84	-0.717	-0.684	-0.727	-0.042	-0.247	-0.329	-0.848	1.654	4.421	3.716
66	COI	3958.361	-17.403	-17.72	-24.654	-21.625	-23.925	-25.177	-23.712	-28.945	-11.621	-47.242	44.003	33.895	29.073	32.753	27.501	22.33	20.458	-0.503	8.236	-0.11	0.466
54	CORONADO - SILVER KING - KYRENE	875.728	14.104	18.329	1.049	-2.293	-4.085	-3.658	-4.117	-2.997	-0.643	-1.991	-1.019	-0.87	-0.829	-0.882	-0.088	-0.336	-0.428	-0.909	1.829	4.929	4.13
77	CRYSTAL - ALLEN	242.657	1.099	1.263	1.604	-5.652	1.829	1.612	1.814	1.992	-0.95	0.938	-0.328	-0.261	-0.227	-0.258	-1.406	-0.522	-0.465	-1.532	-3.298	-1.358	-1.361
49	EAST OF COLORADO RIVER (EOR)	4248.792	56.808	61.62	61.822	-22.472	-26.374	-22.077	-26.374	-24.174	-10.489	-20.192	-14.791	-12.589	-11.935	-12.775	-7.301	-9.195	-9.567	-12.894	4.122	19.478	15.266
62	ELDORADO - MCCULLOUGH 500 KV	-26.998	3.571	2.596	0.872	-14.09	0.924	1.108	0.853	1.999	-3.74	1.191	-0.07	-0.034	-0.008	-0.024	-1.129	-0.128	-0.104	-6.54	-1.713	0.486	0.304
58	ELDORADO - MEAD 230 KV LINES	-177.815	-0.313	-0.496	-3.26	-1.793	-0.256	-0.804	-0.306	0.903	0.394	1.047	0.77	0.658	0.625	0.669	0.355	0.548	0.553	-0.155	-0.012	-0.001	0.064
23	FOUR CORNERS 345/500	24.012	24.492	18.276	-1.403	-6.039	-3.477	-3.77	-3.41	-5.078	-0.781	-3.74	-1.516	-1.296	-1.242	-1.314	0.459	-0.104	-0.325	-2.002	4.987	11.791	10.022
14	IDAHO - NORTHWEST	-85.219	10.242	9.755	8.187	7.141	5.454	4.447	5.518	3.198	16.466	-8.001	-19.206	-15.788	-14.446	-15.723	62.28	-7.316	-7.527	16.944	30.935	18.788	17.331
16	IDAHO - SIERRA	3.657	-2.049	-2.343	-3.332	-4.385	-3.002	-2.852	-2.999	-2.903	-0.694	-0.838	2.958	2.449	2.242	2.455	7.002	2.572	2.459	-24.087	3.659	1.537	1.729
42	IID - SCE	324.489	0.115	0.233	0.515	-0.316	4.105	43.226	4.412	-1.357	-0.689	-1.047	-0.962	-0.817	-0.773	-0.831	-0.668	-0.736	-0.731	-0.559	-0.497	-0.342	-0.397
29	INTERMOUNTAIN - GONDER 230 KV	73.351	-0.24	-0.484	-1.252	-2.119	-1.306	-1.294	-1.3	-1.428	3.901	-0.9	0.132	0.108	0.092	0.109	1.193	0.506	0.436	-5.965	3.9	2.184	2.109
28	INTERMOUNTAIN - MONA 345 KV	49.153	-0.987	-0.728	-0.143	0.894	0.085	0.077	0.083	0.13	42.132	-0.524	-1.645	-1.391	-1.303	-1.411	-2.418	-1.735	-1.641	4.743	-5.174	-3.438	-3.361
60	INYO - CONTROL 115 KV TIE	-49.197	0.028	0.031	0.045	0.018	0.067	0.056	0.066	-0.485	0.675	0.062	0.019	0.017	0.017	0.018	-0.015	0.012	0.013	-0.338	-0.03	-0.005	-0.004
27	IPP DC LINE	892.343	0	0	0.001	0	0	0	0	0	0	0	0.001	0	-0.001	0	-0.001	0.001	0	0.001	0	0	-0.001
61	LUGO - VICTORVILLE 500 KV LINE	1278.41	11.881	12.325	14.455	21.08	0.223	-2.217	0.735	-7.752	20.427	-9.862	-5.843	-5.012	-4.789	-5.104	-1.17	-3.602	-3.766	5.956	4.002	5.474	4.312
75	MIDPOINT - SUMMER LAKE	141.015	6.691	6.308	4.792	4.142	2.816	2.015	2.873	0.912	11.517	-8.181	-11.213	-9.066	-8.207	-8.926	27.984	-2.271	-2.59	11.845	23.286	14.108	13.142
15	MIDWAY - LOS BANOS	-586.297	32.953	36.971	45.108	41.107	47.697	42.605	47.424	52.16	30.319	-22.07	-33.819	-28.866	-27.417	-29.344	-16.64	-23.785	-24.072	1.91	-0.6	6.76	2.722
18	MONTANA - IDAHO	-263.743	1.585	1.539	1.542	1.334	1.217	1.137	1.219	1.093	2.31	0.32	-2.388	-2.205	-2.204	-2.359	1.742	-6.288	-6.869	1.656	3.78	1.694	1.317
8	MONTANA - NORTHWEST	1185.174	3.154	2.799	1.708	0.967	0.828	0.516	0.853	0.039	3.126	-3.273	-11.616	-10.318	-10.044	-10.785	-0.772	71.931	69.057	0.574	11.517	15.03	17.451
80	MONTANA SOUTHEAST	-41.5	-3.414	-3.077	-2.257	-1.451	-1.45	-1.219	-1.465	-0.92	-2.484	1.324	6.416	5.704	5.547	5.96	0.863	16.388	13.548	-0.638	-9.401	-15.663	-18.652
73	NORTH OF JOHN DAY	5705.624	-17.62	-17.675	-21.813	-19.544	-19.788	-20.053	-19.678	-21.936	-17.115	-27.847	23.784	49.031	43.377	48.082	-5.867	32.423	30.797	-18.799	-9.859	-8.161	-6.446
43	NORTH OF SAN ONOFRE	341.763	3.477	4.337	5.578	-0.142	42.593	13.158	40.344	0.964	-2.774	-4.714	-3.89	-3.314	-3.141	-3.366	-2.36	-2.838	-2.849	-1.643	-1.023	0.115	-0.298
26	NORTHERN - SOUTHERN CALIFORNIA	1936.334	-35.966	-39.937	-48.515	-44.094	-50.658	-45.564	-50.373	-55.303	-33.357	41.614	29.942	25.576	24.315	26.007	13.524	20.647	20.996	-4.971	-2.605	-9.896	-5.859
48	NORTHERN NEW MEXICO (NM2)	1702.476	-24.379	-3.73	0.225	0.25	0.236	0.191	0.27	0.285	0.417	0.442	0.616	0.502	0.471	0.511	0.536	0.568	0.514	0.395	0.793	1.99	1.488
3	NORTHWEST - CANADA	1000.117	13.766	13.592	15.635	13.714	13.688	13.631	13.633	14.535	13.867	15.937	17.009	-86.234	-80.129	-87.41	13.753	13.996	13.706	13.7	14.331	14.105	14.085
65	PACIFIC DC INTERTIE (PDCI)	3057.478	0	-0.001	0	0.001	0.001	0	0	0.001	0	-0.001	0	0	-0.001	-0.001	0.001	0	-0.001	0	0.001	-0.001	-0.001
25	PACIFICORP/PG&E 115 KV INTERCON.	59.482	-0.076	-0.076	-0.106	-0.089	-0.102	-0.109	-0.101	-0.125	-0.052	-0.336	0.271	0.174	0.149	0.168	0.109	0.107	0.098	0.076	0.027	-0.005	-0.003
20	PATH C	-914.26	11.071	10.547	9.407	7.36	6.718	5.912	6.761	5.037	21.778	-3.212	-11.879	-9.91	-9.179	-9.973	-19.779	-9.039	-9.104	-0.473	16.324	10.3	8.49
32	PAVANT, INTRMTN - GONDER 230 KV	118.823	-0.088	-0.499	-1.771	-3.394	-1.955	-1.954	-1.943	-2.205	4.819	-1.459	0.164	0.133	0.111	0.135	1.867	0.793	0.68	-11.211	6.673	3.637	3.496

Figure 23. PTDF calculation for WECC zonal model.

Impact of WECC zones on California – Oregon Intertie (COI) is depicted in Figure 24 and Figure 25. From these figures one can see that PG&E and Northwest zones have the biggest impact on the power flow through COI.

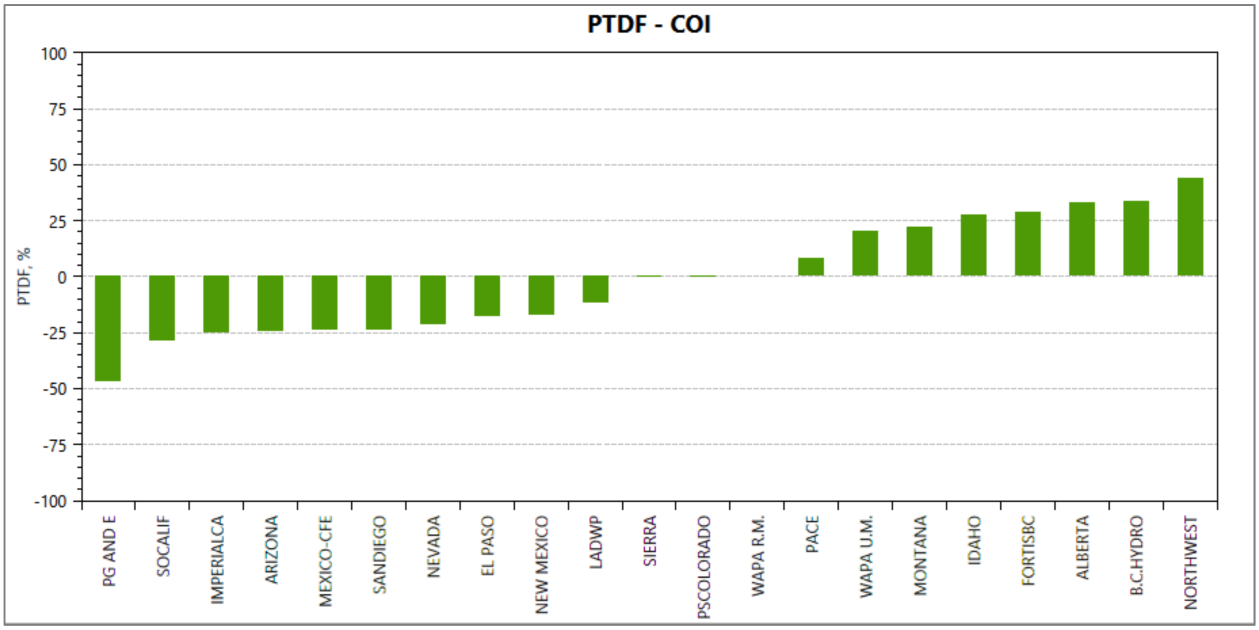

Figure 24. Impact of WECC zones on COI.

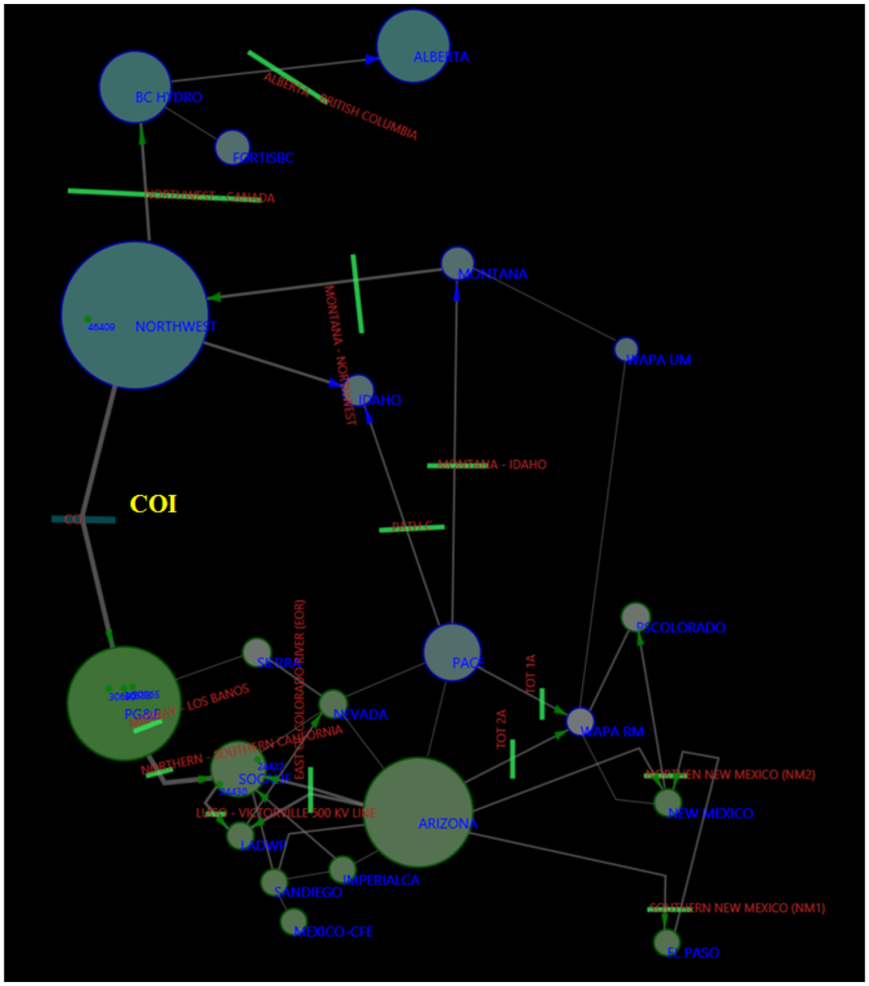

Figure 25. Visual representation of zonal impact on COI (green = negative PTDF, blue = positive PTDF; color shade corresponds to the size of impact).

Another component of the Task 5 scope was a workshop where the TUT methodology and capabilities were presented. It was determined that a webinar would reach a broader audience and due to ease of attending and by avoiding unnecessary travel costs. Two webinars were held with industry participants. The first on August 14, 2015 included 30 industry participants including DOE staff and the second webinar for on September 2, 2015 was held and specifically tailored to a single industry participant.

3.1.7. Task 7: Provide DOE and public accessible data created from project

This task collects and makes available to the DOE for public consumption data that was generated in this project. Data will be shared granted it is allowable given the potential proprietary or sensitive nature of the data. When applicable, data will be masked or normalized to protect confidential or sensitive data.

All appropriate data will be shared which meets the milestone target for Task 7.

4. Significant Accomplishments and Conclusions

As noted in Section 3, most milestones were met or exceeded. Task 5 milestone was not achievable but an equally desirable outcome to industry was pursued, and acheived. Notable accomplishments include:

- Task 2: a target of 5% MAE improvement was sought from the AWST forecasts and the effort resulted in a 12-31% improvement in forecast confidence bands.
- Task 2: a target to reduce uncertainty ranges of net load by 5-10% in normal conditions and by 10-15% during solar generation ramping conditions beyond that which was observed at CAISO. By adopting a decomposition-based and a regression tree short-term forecasting approach we realized significant reductions in forecast error prediction and uncertainty reduction. When the approach is applied to solar generation forecast errors as well as net load forecast errors, tests on 5-min ahead forecast errors showed that uncertainty in net load forecast errors can be reduced with the decomposition-based approach by 10~90%, while uncertainty in solar generation forecast errors can be reduced by 20~80%. Typical reductions of 30-40% can be seen for 15-min and 30-min ahead forecast errors. Using the regression tree approach, tests on 5-min ahead forecast errors showed that uncertainty in net load forecast errors can be reduced by 20~90%, while uncertainty in solar generation forecast errors can be reduced by 10~90%. Typical reductions of 40-50% can be seen even for 15-min and 30-min ahead solar and net load forecast errors.
- Task 5: Due to lack of any relationship between available solar generation data and price spikes, the Task focus was modified to system reliability violation avoidance in a manner that would avoid price spikes. The advancements in this Task along with the benefits made in prior tasks result in tangible and quantifiable system reliability benefits. Periods of significant negative CPS1 scores (-400MW) were run with the new tools and reliability violations while still clearing the same amount of energy for the same price.
- Task 6: The TUT and its methodology showed several important advantages and opportunities for Balancing Areas.
    - Better quantification of available security margins. Because the analyzed transmission impacts are caused by random variations of forecast errors in different parts of the system, they are not predictable in a deterministic sense. Based on a statistical analysis of multiple forecast errors, the tool provided a unique opportunity to adjust security margins depending on the risk (expected size and probability) of potential transmission violations.
    - The advanced probabilistic solar forecast reduced uncertainty range and narrowed the distribution of power flow probabilities through critical transmission interfaces. Thus, using the probabilistic forecasts allows for increase transfer capability margins and therefor also increase secure probabilistic transmission limits of interfaces.
    - Better reliability level. By adjusting the system security margins on critical paths in the system, the tool helped to prevent potential violations caused by random variations of system load and variable generation around their forecasted values.

- o Better utilization of transmission assets. In cases when the deterministic security margin is excessive, the TUT provides recommendations to reduce this margin based on the actual variability of the flows in the analyzed critical paths.
- o Better situational awareness and predictive system monitoring. The TUT algorithm is run for multiple look-ahead dispatch intervals and possible contingencies. Based on this information, system dispatchers will be informed about (1) potential violations and associated risks on all critical paths in the system; (2) the most critical contingencies; and (3) the expected time to violations.
- o Preventive control. As a result of its look-ahead feature, the TUT algorithm leaves some time for mitigation measures, helping to reduce the expected size and probability of violations to an acceptable level.

There was also a great deal of success with knowledge dissemination and outreach as part of the project effort.

Project Presentations:

- Pennock, Kenneth. "Comprehensive Solutions for Integration of Solar Resources into Grid Operations." Presented at Renewable Energy World Conference and Expo, Orlando, FL on December 10, 2014
- Miller LE, YV Makarov, PV Etingov, MR Weimar, B Vyakaranam, and MR Vallem. "Stochastic Planning and Control for Renewable Integration." Presented by Laurie E. Miller (Invited Speaker) at 2015 IEEE PES General Meeting, Denver, CO on July 30, 2015. PNNL-SA-111842.
- Etingov PV, YV Makarov, D Wu, Z Hou, Y Sun, S Maslennikov, X Luo, T Zheng, S George, T Knowland, E Litvinov, S Weaver, and E Sanchez. 2014. "Uncertainty-based Estimation of the Secure Range for ISO New England Dynamic Interchange Adjustment." In 2014 IEEE PES Transmission & Distribution Conference & Exposition, April 14-17, 2014, Chicago, Illinois, pp. 1-5. IEEE, Piscataway, NJ. doi:10.1109/TDC.2014.6863202
- Hou Z, PV Etingov, YV Makarov, and NA Samaan. 2014. "Uncertainty Reduction in Power Generation Forecast Using Coupled Wavelet-ARIMA ." In IEEE PES General Meeting, Conference & Exposition, July 27-31, 2014, National Harbor, MD. IEEE, Piscataway, NJ.

Poster Presentations

- Pennock, Kenneth. "Comprehensive Solutions for Integration of Solar Resources into Grid Operations." Presented at PV America East 2014, Boston, MA on June 25, 2014.
- Pennock, Kenneth. "Enabling Grid Operations with Probabilistic Solar Forecasts." Presented at Solar Power International 2014, Las Vegas, NV on October 22, 2014.

Several outreach activities included presentations on the tools and methods used in this project and were also leveraged by several ongoing and past projects, including projects funded by DOE Office of Electric Delivery and Energy Reliability (OE) and Office of Energy Efficiency and Renewable Energy (EERE), Bonneville Power Administration (BPA), California Energy Commission (CEC), ISO New England, and CAISO. These activities included:

- Hou Z, PV Etingov, YV Makarov, and NA Samaan. 2014. "Uncertainty Reduction in Power Generation Forecast Using Coupled Wavelet-ARIMA ." In IEEE PES General Meeting, Conference & Exposition, July 27-31, 2014, National Harbor, MD. IEEE, Piscataway, NJ.
- The PNNL TUT is used in ongoing project work with BPA and DOE OE on look-ahead probabilistic state estimation.
- IncSys Corporation used PNNL RUT and TUT during power system dispatcher training classes. During these classes (2 sessions – Aug 12 and 13, 2015, 15 participants from industry) several experiments were conducted to demonstrate the efficiency of the probabilistic tools to predict system balancing requirements and eliminate transmission network congestion problems.
- TUT will be also integrated with GridOPTICS framework developed in PNNL. The GridOPTICS™ Software System (GOSS) is a middleware framework that enables the deployment of new applications for the future power grid. This resource easily integrates grid applications with sources of data and facilitates easy communication between them. This activity is funded by PNNL LDRD fusion project.
- PNNL and AWS Truepower are partnering in a recently started project “Solar-Centered Power Grid” (funded by EERE SunLamp). CAISO and the Utility Variable-Generation Integration Group (UVIG) are participating in this project. The project aims to remove artificial barriers for the increasing penetration of solar resources in the National Grid. The TUT and RUT tools will be used for the study.

There were also challenges and delays encountered during the project. One such occurance that caused delays and a scope pivot stemmed from the realization that the forecast temporal resolution and the look-ahead period as scoped were inadequate for CAISO’s modified operations. The need for revised forecast parameters coincided with the CAISO operational transition to forecasts with a 5 minute resolution, which also reflects the timing in the new CAISO market of 5-minute forecasts resolution and 15-minutes scheduling for interchange, based on Federal Energy Regulatory Commission Order 764. The project was originally scoped to focus on 2013 but given the significant market transition that occurred at CAISO during the project, CAISO, the project team, and DOE, determined that the project should be refocused to a period of time that would be relevant to the CAISO market as it stands today. Additionally, CAISO was unable to retrieve data necessary for the project from the 2013 period that was archived given the market transition.

Additionally, the focus of the experiments in Task 5 were targeted to focus on price spikes but as observed, we were able to rule out that the spikes were related to utility scale solar energy variability. We ruled this aspect out by comparing the price patterns to that of renewable energy generation during the price spike instances. There is sufficient logical reasoning for this finding. The market application formulation as existed in October 2014, for example, for flex ramp constraints in the CAISO market applications had already performed the needed existing designed basis to achieve price spikes during renewable variability. This formulation was aimed at managing such price excursions in the event of not deterministically or unexpected variability of renewable energy. In general, for energy products in the market, when there is ramping in-sufficiency irrespective of the root cause, positive or negative price spikes are the associated symptoms that are observed and they fade away when the ramping and dispatch catch up over a longer time than that of the desired. At the time of market execution (binding for a time interval in the future), the set aside flex ramp quantities had prevented the ramping insufficiency, and subsequently the price spikes as well which are associated with this phenomenon.

What we instead observed were reliability violations (frequency and ACE) during high amounts of solar variability. There were no related price spikes because they were already mitigated by the CAISO market flex ramp up constraint. The reliability violations are of paramount importance to CAISO operations and became the focus of the experiments. The goal then became to determine if by using output from RUT, that had ingested the probabilistic forecasts, in the Siemens market applications, reliability violations could be avoided and CPS1 scores could be improved.

It should be noted that ramping insufficiency in this context implies the presence of a physical limitation (inability) to provide the needed energy on-time with the existing set of economic resources. It further implies the energy necessary to resolve the insufficiency would be procured from more expensive generators. In the future, there is the potential to have more energy storage and/or more fast gas turbines added to the grid which, in theory, could help address the insufficiency and thereby minimizing the duration of increased prices.

A CAISO market structure change for adding Flex Ramp as an AS product is under review and in plan for Fall 2016. In light of the positive results of this project, such a change would be relevant and useful even if deterministic forecast were used to schedule renewables by allowing flexibility in a planning sense for the next five minutes.

Finally, this study concludes that energy prices for the next five minutes are managed better with the advancements tested in the study. Further, this study illustrates several examples of real time reliability issues (CPS1) and validates the use of 85% or 90% probabilistic forecast and ramping requirements to manage the real-time issues from both a pricing and reliability aspect.

5. Inventions, Patents, Publications, and Other Results

No inventions were developed and no patents were submitted under this award. All relevant conference proceedings, outreach efforts, and related continuation efforts are identified in Section 4.

6. Path Forward

As described in Section 4, several projects are underway that expand on the RUT, TUT, and probabilistic forecast processes that were used in this project. Regarding the licensing or use of the PNNL applications within industry, Battelle as operator of PNNL for DOE, exercises its Bayh-Dole rights under its government-sponsored projects. Battelle has contracts in place with DOE that 1) establish U.S. Government and Battelle rights to any intellectual property (IP) generated under the project, and 2) manage any technology transfers from PNNL to industry. IP and technology transfer matters will be handled in accordance with contract requirements and are managed by a PNNL Commercialization Manager and the Intellectual Property Legal Services office (IPLS).

Many of the PNNL grid-related technologies are software-based and are protected via copyrights. These copyrights are valid for a five-year period with up to two subsequent renewals. For federally funded entities (even via a subcontract), PNNL software is provided under a

Government Use Acknowledgement to provide access for a federally funded project's duration. For those software codes that would be most impactful with a wide-scale deployment strategy that is ultimately supported by a user community, BSD-style open source licenses are used. Otherwise, software is distributed under a nonexclusive basis, generally with a royalty or fee structure that is linked to the number of software site licenses granted by the licensee. Currently, CAISO is using the RUT algorithm under a royalty-free license. Other entities can obtain the tool as described above.

Also, there are logical improvement needed in regulation up/down allocation computation that can be performed every 5 minutes instead of 15 minutes as a current practice and tariff. This change will require a detailed stake holder process changing the periodicity along with the needed co-optimization of energy, regulation reserves and flex ramp reserves for this new and recommended 5 minute periodic formulation.

There is a subsequent need to provide a proxy to AGC, to further optimally allocate the reserves provided in the five minute basis and to utilize the same as needed every 6 seconds. When the Flex Ramp becomes an AS product, such changes to AGC are possible.

A higher frequency of RTD of the CAISO market, 2 minute periodicity for example, is idealistic but may not be realistic and would take substantial engineering and investment. An RTD wall clock time of two minutes, for input processing, co-optimization and network constraints, output processing, and interface data transmission, and saving case creation, would be very difficult to achieve given today's computing capabilities and process involved with market modifications. Thus the measures mentioned above are more pragmatic and realistic to achieve. Nevertheless, such two minute periodicity should be studied for feasibility and established as a roadmap initiative as the solar penetration rate increases further, and as more energy storage capacity is established on the grid in the wholesale markets.

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