

Multi-Settlement Simulation of Reserve Procurement using Stochastic Optimal Power Flow

Taiyou Yong, *Member, IEEE*, C. Russ Philbrick, *Senior Member, IEEE*, Robert Entriken, *Senior Member, IEEE*, and Aidan Tuohy, *Senior Member, IEEE*,

Abstract— This paper presents a dynamic reserve determination method that can be applied to operations in order to facilitate renewable integration. The method is applied to a realistic system model and incorporates a multiple settlement process that includes a day-ahead unit commitment cycle, an hour-ahead cycle, and a real-time 5-minute cycle. By inserting dynamic reserve determination in the hour-ahead cycle, the reserve requirements were dynamically procured to mitigate forecast errors in the renewable generation. The study demonstrates the use of a dynamic reserve procurement step that is practical for deployment in existing business processes and presents an example of new operating policies that can be used to integrate renewable integration at lower cost while maintaining system reliability.

Index Terms—Wind farms, Power generation dispatch, Power system analysis computing, Power system economics.

I. INTRODUCTION

THIS paper describes a detailed simulation of dynamic reserve procurement in the commitment and dispatch of Day-Ahead, Hour-Ahead, and Real-Time operations. This simulation model is used as a platform for evaluating reserve-procurement policies and, in particular, the feasibility and impact of stochastic optimal power flow (STOPF) used to define dynamic-reserve requirements. The simulation model is applied to an approximate model of the power system of Southern California Edison and its participation in the power markets run by the California Independent System Operator (CAISO). The two significant contributions of recent work described in this paper are to demonstrate:

- The ability to simulate and deploy dynamic reserve-procurement policies based on STOPF and
- The potential benefits that dynamic reserve-procurement policies offer to System Operators and consumers.

The operation of the power grid can be described as a

decision process that develops over multiple decision cycles. Indeed, the concept of decision cycles is a key attribute of real operations that must be captured in planning studies to accurately model impacts of changing policies, whether these are in a market setting or simply executed as internal processes.

The audience for this paper is system operators, planners, and market designers who are exploring new policies to accommodate variable generation being added to their systems and are quantifying their impacts. As background and motivation, we provide an introductory section that describes trends, a test system, and tools and models used to create the simulation model. Following the background section, we provide a high-level description of the methodology and, through experimentation, illustrate the capabilities and benefits of STOPF.

The objective of this study is to demonstrate how probabilistic forecasts can be incorporated in current operational processes using a realistic system model and operations process. By inserting the reserve determination step as an off-line calculation, the experiments illustrate a practical implementation strategy and provide a preliminary assessment of the improved flexibility that can be provided to system operators during periods of particular system stress.

Background

The background section describes key industry trends influencing system operations, the California Independent System Operator (CA-ISO) 33% Study, which forms the test case for comparison of alternative reserve procurement processes; and the resource scheduling problem, which is being simulated with the Power System Optimizer (PSO) model.

A. Industry Trends

1) High Levels of Wind Generation

Few industries are scaling up faster than wind power, which, in terms of installed capacity in the U.S., has been increasing at a rate of more than 25% per year. New wind turbines are bigger, wind farms are larger, and the manufacturing base is more diverse and more robust, both domestically and globally. The extraordinary growth in wind power is being driven by policy, regulation, and economics in the U.S., Europe, and elsewhere in the world.

This work was supported by the Electric Power Research Institute (EPRI). T. Yong is with Eversource Consulting, Folsom, CA, 95630 USA (e-mail: taiyou_yong@yahoo.com).

R. Philbrick is with Polaris Systems Optimization, Shoreline, WA, 94177 USA (e-mail: russ.philbrick@psopt.com).

R. Entriken is with EPRI, Palo Alto, CA, 94304 USA (e-mail: rentrike@epri.com).

A. Tuohy is with EPRI, Knoxville, TN, 37932 USA (e-mail: atuohy@epri.com).

The impact of U.S. federal policy is most clearly seen in the impact of the production tax credit (PTC), which is worth about \$20/MWh. At the state level, renewable portfolio standards (RPS) have a significant impact on creating a market for wind power. As of June 2011, U.S. wind capacity stands at 42 GW [1].

The European Wind Power Association projects between 230-265 GW of wind will be installed in Europe by 2020, of which 40-55 GW will be offshore [2]. By 2030, this total could climb to 400 GW, raising wind power contributions to the same level as more conventional contributors to the European generation portfolio. Wind is forecast to represent between 14-17% of European electricity by 2020, and between 26-34% in 2030. Germany alone is anticipating 50 GW of wind by 2020, which would represent more than 50% of its peak load.

With such significant levels of wind integration, new balancing techniques and better forecasting are needed for System Operators to maintain power system security. Even with significant improvements in recent years, forecasting of wind generation remains inaccurate. Furthermore, even with perfect forecasting, wind resources are highly variable and often blow hardest during off-peak hours and seasons. Due to its sometimes limited availability during times of peak demand, wind power may provide limited capacity to support resource-adequacy requirements. The impact of wind power's uncertainty and variability motivate the introduction of new policies for determining reserve requirements with the goal of identifying methods that can make better use of system flexibility to maintain system reliability and improve economic performance.

2) *New Supply- and Demand-Side Technologies*

A wide array of new supply-side and demand-side technologies will be integrated into the grid in the coming decade as part of efficiency and smart-grid initiatives. As their use grows, their impact will complicate both load and generation forecasting by introducing higher levels of variability in supply, new kinds of uncertainty in demand, and non-traditional participants in grid operations.

Demand-Response: The introduction of demand response, designed primarily to shave peak demand, has accelerated in many regions of the country. FERC's 2011 DR and AMI Survey [3] indicated that advanced metering penetration reached 13.4% of total meters in 2010, up from less than 8.7% in 2009. The survey estimates the peak load reduction from demand response to be over 31 GW in 2010, representing approximately 7.0 percent of the 2010 peak ISO/RTO electricity demand.

Solar Thermal Energy: Large arrays of solar thermal technology in the California, Nevada, and Arizona deserts may impact the power system at the transmission voltage levels; however, new transmission lines are needed to move the estimated 13 GW of solar energy to California markets.

Solar Photovoltaic (PV): PV will continue to serve local area needs at distribution voltages, reducing daily demand moderately during the solar peak (generally a few hours

before load peak). The PV market could reach 10GW penetration in the US by 2020 [4].

Plug-in Electric Vehicles: The vehicle-to-grid concept (V2G) includes two-way grid interchange of power, allowing plug-in electric vehicles (PEV) to receive and send power to the grid. The installation of charging stations has already begun in a number of urban and suburban areas of the country.

Energy Storage: Energy storage technologies enable the decoupling of the instantaneous supply of energy from the variable nature of demand and variable supplies; this enhances the integration of variable renewable resources into the grid and the provision of ancillary services.

3) *Evolving Reliability Standards*

There is a possibility that reliability organizations will introduce a risk-based transmission planning process. If so, system and operations planners should expect to draw heavily upon the "availability databases," like those built and populated by the North American Electricity Corporation (NERC). Significant events involving generation, transmission, and demand response are reported to NERC and introduced into one of three databases: GADS for generation, TADS for transmission, and DADS for demand response. GADS is the longest running database, TADS is about three years old, and DADS is still in the formative stage. In time, these databases will become powerful instruments for understanding the statistical distribution of equipment availability.

With better knowledge of overall reliability and behavior of these system resources, probabilistic techniques, such as the ones described in this report, will become more practical to implement and more valuable to planners, operators, and consumers.

B. *California ISO 33% Study*

Data used in developing the test system for this project was drawn from the California ISO 33% Study [5]. California has an ambitious goal to supply 33% of electricity demand through renewable resources by 2020 [6]. To meet state policy requirements while maintaining system reliability, the California ISO performed studies on the operational impacts of renewable integration including the requirements for additional ramping support and load-following capability, the market impact of over-generation events, increased cycling of generating units, etc.

The California ISO worked with many entities to develop analytical methods for studying the operational and market impacts associated with the integration of renewable generating resources, primarily wind and solar. The studies [7] include statistical modeling of operational requirements, production simulation of unit commitment and economic dispatch, the impact of forecast uncertainty, empirical analysis of historical generator capabilities, market and dispatch schedules, sensitivity analysis of forecast uncertainty and impacts on the requirements for generating capacity and operating reserves etc.

The California studies attempted to capture the real-time operation process and the support provided by market processes having different time frames within the 2020 study year, including:

- Day-ahead energy and ancillary-services market,
- Day-ahead resource-adequacy (i.e., reliability) procurement of ancillary services,
- Hour-ahead “Pre-dispatch” and short-term commitment process that commits fast-start units and schedules the interchanges one to four hours ahead of real time operations,
- Ten-minute ahead “real-time” dispatch that dispatches units every five minutes to meet load ramping and deviation of generation.

In addition, after “real-time” dispatch, Automatic Generation Control (AGC) regulates fast-responding units to balance the system and maintain system frequency.

In this study, we use data provided by the California studies, but limit our simulation to the day-ahead energy and ancillary-services market, the hour-ahead pre-dispatch process, and the real-time dispatch, which is used to quantify impacts of earlier decisions.

C. Resource Scheduling Problem

Electrical systems include a range of different generating resources, including fossil-fuel units, hydro-power units, nuclear units, and renewable-resource units such as solar and wind. Different units can have significantly different operational characteristics, even among similar resource types. These operational characteristics include startup time and cost, minimum run time, cycling costs, ramp capability, and so on. Also, some generating units such as solar-power and wind-power units have output that is highly variable and may have limited control facilities.

To address these characteristics while also ensuring reliable and efficient operations, system operators issue instructions with sufficient lead time to commit long-start units, to move slow-ramp units early to meet the projected load changes, and to procure sufficient reserves for the real time imbalance and contingencies. In real-time operations dispatchers adjust fast-moving units to balance load and respond to conditions not anticipated earlier in the process. The day-ahead, pre-dispatch, and real-time decision cycles repeat daily, hourly, and every 5 to 10 minutes to match continually supply and demand.

Due to the computational challenges of the resource scheduling problem, traditional approaches have greatly simplified the operational impacts of planning and scheduling decisions. With the integration of new types of resources with non-traditional operational characteristics, traditional planning approaches present an inaccurate picture of impacts and costs associated with these resources and the changing operating policies that may be required to support their integration. In this study, new methods and tools have been deployed to overcome these traditional limitations, while also demonstrating the ability of these methods to support

operational decision making and the feasibility of deploying these methods and tools with minimal disruption to current control-room business practices.

D. Objective

The main objective of this study is to demonstrate how Dynamic Reserve Determination could be implemented in practice. This demonstration utilizes a realistic system model that accurately captures the operational processes described previously. By inserting the reserve determination step as an off-line calculation, based on the current system state and perceived uncertainties, the following experiments show beneficial enhancements to system flexibility afforded to operators during periods of particular system stress. This is evidence of the value of using stochastic information to determine dynamic (hourly) reserve requirements, versus the more traditional reserve requirements.

II. MULTI-SETTLEMENT PROCESS MODEL

Realistic simulation of the resource scheduling problem is achieved using PSO support of multi-cycle, rolling-horizon models that capture the impact that imperfect foresight has on unit-commitment and energy-scheduling decisions. Fig. 1 illustrates the time frame of the multi-cycle model. Typically, each decision horizon considers three periods of time, the *initial time*, the *target time*, and the *future time*. Within the initial time, the initial conditions of generating resources that are necessary for scheduling continuity are set for the study horizon. The *target time*, and the *future time* are the time periods in which schedules and commitments are solved. Decisions in the *future time* period will be revisited in the following horizon, but are needed by the current horizon to correctly model the impact of long, inter-temporal constraints and costs (e.g., minimum run time and startup cost)..

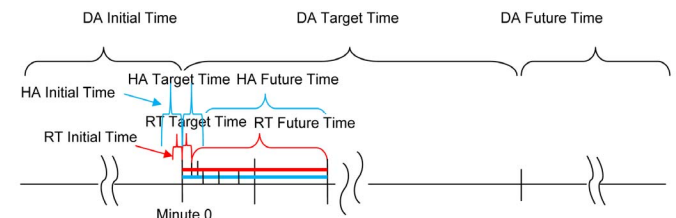


Fig. 1. Time Frame of Multi-Cycle Model

To model real system operations, the PSO model is configured with three cycles. The DA cycle covers 48 hours in which every hour in the first 24 is a decision period, every 2 hours in the second 24 hours is a decision period. Therefore, there is a total of 36 periods in the DA cycle. The pre-dispatch cycle covers a 4-hour horizon, i.e. 16 periods of 15-minute decision periods. The real time dispatch cycle covers a 1-hour horizon, in which there is a total of twelve 5-minute decision periods.

III. DYNAMIC RESERVE DETERMINATION MODEL

Achieving high penetration of renewable technologies with their variable generation characteristics will require changes in the ways that electric power systems are planned and operated to maintain reliable and economical service. As part of the effort, in the past years, EPRI has performed research on applying the stochastic optimal power flow (STOPF) method to energy scheduling and reserve determination and proposed a dynamic reserve determination method that identifies the system operating reserve requirements based on the needs of redispatch to meet system uncertainties, such as equipment outage, demand variation, and variable generation [9].

The dynamic reserve determination method is a co-optimization problem of energy scheduling and reserve procurement. It represents an optimal dispatch under uncertainty, which can be applied to assess system operating reserve requirements with large penetrations of variable generation. The same philosophy can be applied in the energy scheduling process. Integrating the STOPF-based reserve determination with the unit commitment process can lead large potential cost reductions in energy scheduling and improvements of system reliability when the system dispatch is also integrating large-scale intermittent generation.

In this study, the simulation tool solves a stochastic dispatch model with multiple scenarios. All scenarios are solved simultaneously, with some variables identified as stage 1 decisions that do not vary by scenario, and some variables identified as stage 2 decisions that are scenario dependent.

This study adopts such a stochastic model to analyze the impact of intermittent renewable generation. For demonstration purposes, only the uncertainty of renewable generation is included as a source of imbalance. Other sources like load forecast errors and generator outages are left for future study. When applying the STOPF method, energy dispatch is identified as the sum of a first-stage variable and a second-stage “re-dispatch” variable. Reserve levels are designated as stage 1 variables and are used as upper bound constraints on the re-dispatch variables. Thus, the dispatchability of generators is limited to the amount of variable reserves in each solution interval. The resource constraints can be formulated as follows. For each resource,

$$P(t, s) = P_{sch}(t) + P_{redisp}(t, s), \quad \text{and}$$

$$R_{LFD}(t) \leq P_{redisp}(t, s) \leq R_{LFU}(t)$$

where t is the index of periods of time, s is the index of scenarios. $P_{sch}(t)$ is the consistent dispatch schedule across all scenarios, $P_{redisp}(t, s)$ is the redispatch for each scenario. In practice, $R_{LFD}(t)$ and $R_{LFU}(t)$ are the optimally-procured dynamic load following down and up capacities. In our later experiments, only LFD is optimized.

The total load following up/down over all generators is the system requirement for load following up/down in the time period.

IV. TEST SYSTEM DATA

The primary objective of the following simulation study is to demonstrate the dynamic reserve determination in realistic system operations. The data in the simulation is a portion corresponding to the SCE service territory, as defined by CAISO in their 33% renewable integration study. The characteristic data of generating resources are almost the same as that in the PLEXOS [10] model published as part of the renewable integration study. One difference is that there is no transmission modeled here; while in the CAISO study, only transmission between major regions is modeled. EPRI expects to include transmission constraints in future work. Since the main purpose in the current study is to examine scheduling and dispatch of resources in systems with high amounts of variable generation, the lack of transmission is not as significant as it otherwise might be for other purposes.

Hydropower and interchange are modeled as fixed schedules in the SCE model based on results of the CAISO study. Total renewable generation (both wind power and solar power) is modeled as dispatchable, but with maximum output based on the CAISO study. The CAISO study includes a set of wind, solar, and load data with 1-minute resolution based on the 2006 actual results and a projection of future demand, wind and solar power.

For demonstration purposes, this study focuses on the period between July 1 and July 15, 2020, a period of stress due to high summer demand. Fig. 2 shows the SCE load, net import, hydropower, and renewable generation schedules for the study period. These SCE-only wind and solar data are not available explicitly in the CAISO data. Instead, they are estimated from the California data using the ratio of SCE load to the total CAISO load. While these values may not reflect truly the level of wind and solar in the SCE system, they are sufficient for this study. In reality, the localized SCE wind and PV data may be slightly more variable than the combined values over the CAISO territory.

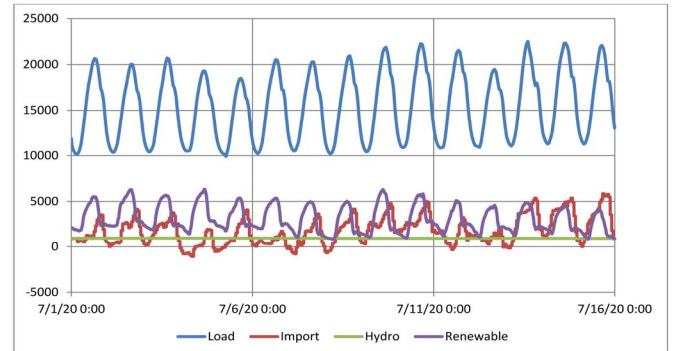


Fig. 2. SCE load, import, hydro and renewable schedules between July 1 and July 15, 2020

Fig. 3. shows the SCE load following up and down and regulation up and down requirements over the study period. Since, SCE-only reserve data are not available, it is also prorated from the total CAISO reserve requirements using the ratio of SCE load over the CAISO system load.

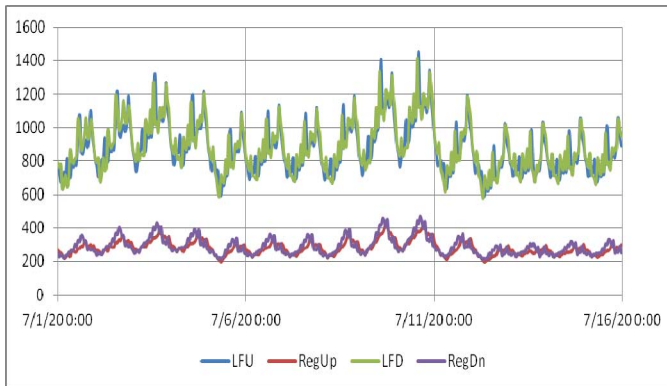


Fig. 3. SCE Load Following Up/Down, Regulation Up/Down Requirements

V. RESULTS OF DYNAMIC PROCUREMENT

Because the focus is on hour-ahead dynamic-reserve procurement, the DA cycle is used to define unit-commitment results (other than for fast-start units) without considering uncertainty. The results of this cycle are applied as prior decisions for the hour-ahead cycle and are consistent in all experiments. The reserve requirements of regulation up/down and load following up/down have the same values as in the static reserve procurements.

The uncertainty of renewable generation is included in the pre-dispatch cycle. Similar to current practice, there is a decision point in the hour-ahead to procure additional reserves for real-time operation, and this is used by the dynamic reserve procurement process to identify the need for additional reserves, or the ability to relax reserve requirements. For the sake of simplicity, only load-following up in the pre-dispatch cycle is set to be dynamically procured, the regulation up/down and load-following down are still procured using the same requirements as in the static reserve model and can be provided by wind and solar curtailments.

In the real time dispatch cycle, renewable generation capacity is based on the CAISO data, and units committed in the DA and pre-dispatch cycles are redispatched to meet any imbalance. Load following up is released in RT to be available for energy dispatch.

Fig.4 shows that the quantity of Load Following Up procured by the dynamic method is much less, on average.

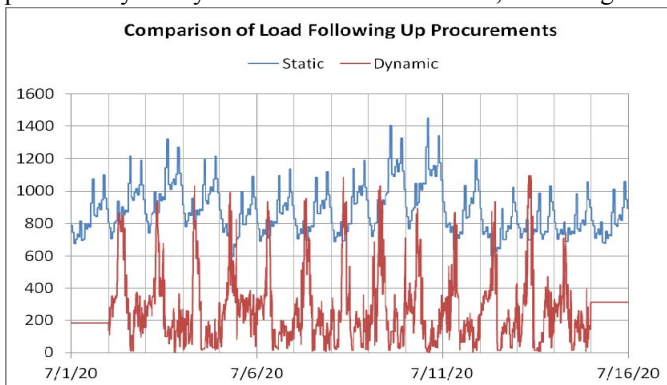


Fig. 4. Load Following Up Procurements for Static and Dynamic Reserve Procurement Simulations

This comparison also shows lower operating costs. A subject of further analysis is to compare the static and

dynamic methods based on both cost and reliability changes. Another subject of future study is to include more of the factors that determine the static requirement.

VI. VALIDATION OF DYNAMIC RESERVE PROCUREMENTS

In this section, the dynamic reserve procurement method is validated in the real-time cycle by utilizing the dynamic method of determining the amount of load following up, instead of the static value.

Table I shows a comparison of the total production costs between two runs. One is the run with the set of static load following up requirements; the other is the run with the set of requirements equal to the dynamic reserve procurement in the stochastic model. The run with the dynamic reserve procurement incurs less cost. There is a 9% savings to consumers.

TABLE I. TOTAL PRODUCTION COST FOR STATIC AND DYNAMIC RESERVE PROCUREMENT SIMULATIONS

Static	Dynamic	Delta Cost	% Change
126,014,101	114,703,621	-11,310,479	-9.0%

Fig. 5 shows a comparison of the energy prices in the pre-dispatch cycle for static and dynamic load following up requirements. There was no deficiency and the overall energy prices were close, but there were fewer spikes in the run with dynamic reserve procurement.

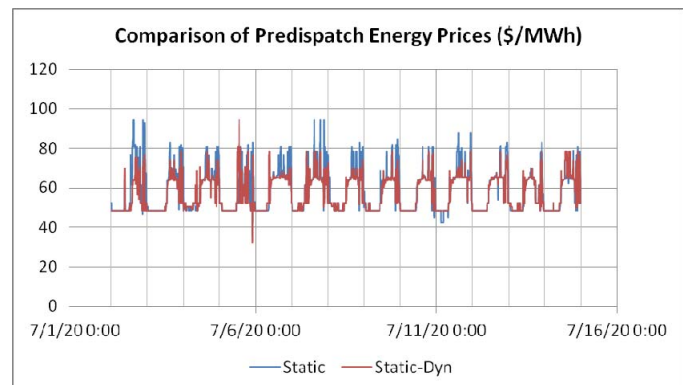


Fig. 5. Comparison of Pre-dispatch Energy Prices for Runs with the Static and Dynamic Load Following up Requirements

Fig. 6 shows the real time energy prices for these two runs. No deficiency occurs the real time cycle. Therefore, system reliability was maintained by the dynamic reserve procurement for the study period and the circumstances represented over the random scenarios and nominal outcome.

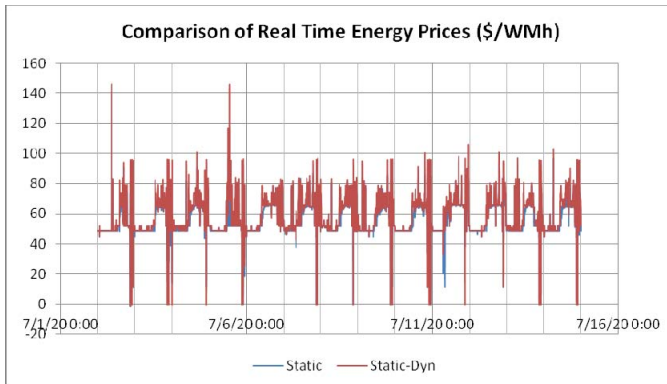


Fig. 6. RT Energy Prices for Static and Dynamic Load Following up Requirement Simulations

The prices seen in this figure appear to be more variable using dynamic procurement as a result of being dispatched more efficiently and, thus, with less excess capacity and cost.

According to the dynamic procurement, it appears that the static reserve requirements may be too conservative in the pre-dispatch cycle, but additional realism, like a transmission model and non-prorated inputs, would be needed to validate this.

VII. SUMMARY OF RESULTS

The experiments successfully demonstrate the application of dynamic reserve procurement in a realistic process of real operations. A few observations can be drawn from the experimental results.

- The reserve procurement determined by the STOPF method can be inserted into the current market pre-dispatch process to potentially better manage reserves.
- The static requirements of the 33% Study may over-procure reserves under some system conditions, leading to higher production costs or capacity requirements.

While this work is very preliminary, the experiments still lead to the following conclusions:

The dynamic reserve determination method can be successfully integrated into the simulation of a realistic unit commitment and energy scheduling process. The level of reserve is determined by the need to redispatch for the system variability and uncertainty, such as from load forecast errors, intermittent renewable generation, etc.

The exercise demonstrated how to apply dynamic reserve procurement in realistic operations, using a multi-cycle model that simulates current dispatch and operations for energy scheduling and reserve procurements.

Without changing existing business rules and practices, inserting the dynamic reserve procurement step into the pre-dispatch can provide benefits via assessing the sufficiency of existing reserve procurement practice and identifying a reasonable level of reserves.

Because of its realism, the stochastic model could be useful for studying the potential for renewable resource integration in system planning and operations.

VIII. ACKNOWLEDGMENT

The data used in this report is based on the CAISO 2020 33% renewable integration study. The simulation tool—Power System Optimizer (PSO)—was provided by Polaris Systems Optimization Inc.

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X. BIOGRAPHIES



Taiyou Yong received the B.S. and M.S. degrees in Electrical engineering from Tsinghua University, China, in 1991 and 1995, and Ph.D. degrees from The University of Wisconsin-Madison in 2001. He is currently a consultant in Eversource Consulting Inc. He previously served as a consultant for the California ISO on market operations from 2005 to 2009, a senior application engineer for ABB Inc from 2000 and 2005. His interests include energy market related strategy study and design, power system operations related analysis and optimization, renewable integration and impacts of new technologies.



Philbrick (M'99, SM'09) received his B.S. from Duke University in 1983 and his M.S. (1994) and Ph.D. (1997) from Stanford University.

He currently is with Polaris Systems Optimization, Inc. founded to support integration of renewable energy into power-grid planning and operations. He has previously served as Principle Power Systems Engineer with ALSTOM Grid (1999 to 2010) and on the faculty of Washington State University and Albrook Hydraulics Lab (1997 to 1999). As a submarine officer in the U.S. Navy (Active duty 1984 to 1989, and Navy Reserves to present), his experience includes nuclear

plant operations and shipyard overhaul. His fields of interest include operations research, business process analysis, economics, numerical modeling, probabilistic methods, and optimization. He has lead development of security constrained unit commitment and economic dispatch tools, and other applications that support electrical utilities and energy markets.



Dr. Robert Entriken (M'1982, SM'2007) manages the policy analysis program at EPRI and co-manages EPRI's power market design task force, which addresses electricity restructuring issues and develops power market design methods and tools.

He worked on a research project focused on refinery scheduling at the Koninklijke/Shell Laboratorium in Amsterdam, Netherlands, as well as co-developed a large economic model of the U.S. electric power industry at Stanford University.

Dr. Entriken is co-author of AIMMS: The Modeling System from Paragon Decision Technology (1993), and Risk Assessment and Financial Analysis, an IEEE PES tutorial (1999). In addition, he has developed economic and financial software for Bank of America, Goldman Sachs & Co., Royal-Dutch Shell Group, Pacific Gas & Electric, and EPRI.

Dr. Entriken holds a B.S. degree in Electrical Engineering from Carnegie Mellon University, holds M.S. and Ph.D. degrees in Operations Research fro

Aidan Tuohy received the B.E. degree in Electrical and Electronic Engineering from University College Cork, Ireland in 2005 and the Ph.D. degree in power systems and wind energy at the Electricity Research Centre, University College Dublin in 2009. He works currently at the Electric Power Research Institute, Knoxville, TN, and Stanford University.