Rulemaking 12-03-014 (LTPP Local Reliability Track I)

Exhibit No. ______________________

Witness Mona Tierney-Lloyd

Commissioner Michel P. Florio

ALJ David R. Gamson

ENERNOC, INC.

LOCAL RELIABILTY TRACK I
SUPPLEMENTAL TESTIMONY OF MONA TIERNEY-LLOYD

Rulemaking 12-03-014
Long Term Procurement Plans (LTPP)
Track 1 (Local Reliability)

July 25, 2012

ENERNOC, INC.
SUPPLEMENTAL TESTIMONY OF MONA TIERNEY-LLOYD
RULEMAKING (R) 12-03-014:
LONG TERM PROCUREMENT PLANS (LTPP): LOCAL RELIABILITY TRACK I

By oral ruling at the Prehearing Conference (PHC) held in the Long Term Procurement Plans (LTPP) Local Reliability Track 1 on July 9, 2012, Administrative Law Judge (ALJ) Gamson directed that citations in Opening Testimony to weblinks (URL) or on-line documents would not be accepted. To the extent that a party wished to rely on such cited material, ALJ Gamson directed that a hard copy version of relevant pages must be provided by Supplemental Testimony served by July 25, 2012.

By this Supplemental Testimony, EnerNOC, Inc. (EnerNOC) provides the relevant pages from on-line or weblink citations used in the Opening Testimony of Mona Tierney-Lloyd served on behalf of EnerNOC on June 25, 2012. The footnotes where such citations occurred are noted, followed by the relevant pages from the cited document.

ENERNOC OPENING TESTIMONY OF MONA TIERNEY-LLOYD
JUNE 25, 2012

Footnotes 16, 17, and 18, at Pages III-1 to III-2

National Renewable Electricity Laboratories (NREL)

Western Wind and Solar Integration Study:
Executive Summary

May 2010




WESTERN WIND AND SOLAR INTEGRATION STUDY:

EXECUTIVE SUMMARY

PREPARED FOR:

The National Renewable Energy Laboratory

A national laboratory of the U.S. Department of Energy

PREPARED BY:

GE Energy

MAY 2010

NOTICE

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WESTERN WIND AND SOLAR INTEGRATION STUDY:
EXECUTIVE SUMMARY

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Prepared under Subcontract No. AAM-8-77557-01

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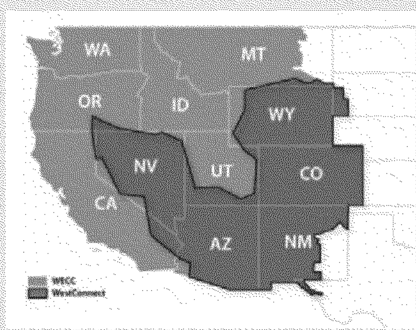
Finally, we thank Bruce Green (NREL) and Mark Schroder (Purple Sage Design) for designing this Executive Summary and the full report.

INTRODUCTION

The focus of the Western Wind and Solar Integration Study (WWSIS) is to investigate the operational impact of up to 35% energy penetration of wind, photovoltaics (PVs), and concentrating solar power (CSP) on the power system operated by the WestConnect group of utilities in Arizona, Colorado, Nevada, New Mexico, and Wyoming.[1] WWSIS was conducted over two and a half years by a team of researchers in wind power, solar power, and utility operations, with oversight from technical experts in these fields. This report discusses the development of data inputs, the design of scenarios to address key issues, and the analysis and sensitivity studies that were conducted to answer questions about the integration of wind and solar power on the grid.

WESTCONNECT

WestConnect is a group of transmission providers that are working collaboratively on initiatives to improve wholesale electricity markets in the West. Participants include Arizona Public Service, El Paso Electric Co., NV Energy, Public Service of New Mexico, Salt River Project, Tri-State Generation and Transmission Cooperative, Tucson Electric Power, Western Area Power Administration, and Xcel Energy.



The technical analysis performed in this study shows that it is operationally feasible for WestConnect to accommodate 30% wind and 5% solar energy penetration, assuming the following changes to current practice could be made over time:

- Substantially increase balancing area cooperation or consolidation, real or virtual;
- Increase the use of sub-hourly scheduling for generation and interchanges;
- Increase utilization of transmission;
- Enable coordinated commitment and economic dispatch of generation over wider regions;
- Incorporate state-of-the-art wind and solar forecasts in unit commitment and grid operations;
- Increase the flexibility of dispatchable generation where appropriate (e.g., reduce minimum generation levels, increase ramp rates, reduce start/stop costs or minimum down time);
- Commit additional operating reserves as appropriate;
- Build transmission as appropriate to accommodate renewable energy expansion;
- Target new or existing demand response programs (load participation) to accommodate increased variability and uncertainty;
- Require wind plants to provide down reserves.

In addition, suggestions for follow-on work to further explore these and additional mitigation options are listed in the Conclusions and Next Steps section.

[1] WestConnect also includes utilities in California, but these were not included in WWSIS because California had already completed a renewable energy integration study for the state.

BACKGROUND

WWSIS and its sister study, the Eastern Wind Integration and Transmission Study (EWITS), follow the U.S. Department of Energy's (DOE) 20% Wind Energy by 2030 Study that considered the benefits, costs, and challenges associated with sourcing 20% of the nation s energy from wind power by 2030 [1, 2]. The study found that while proactive measures were required, no insurmountable barriers to reaching 20% wind were identified. Thus, DOE and the National Renewable Energy Laboratory (NREL) embarked upon WWSIS and EWITS to examine, in much greater depth, whether there were technical or physical barriers in operating the grid with 20% wind. Solar power was included in WWSIS due to the significant solar resources and solar development in the West.

> **BALANCING AREAS**
> Balancing areas are responsible for balancing load and generation within a defined area and maintaining scheduled interchanges with other balancing areas.

Four of the five states in WestConnect have Renewables Portfolio Standards (RPS) that require 15-30% of annual electricity sales to come from renewable sources by 2020-2025. Additionally, WWSIS models the entire western interconnection, examining the operating impact of up to 23% penetration of wind and solar in the rest of the Western Electricity Coordinating Council (WECC). Most of the states in WECC have similar RPS requirements and renewable energy growth in the region has been significant.

The study was designed to answer questions that utilities, Public Utility Commissions, developers, and regional planning organizations had about renewable energy use in the West:

- What is the operating impact of up to 35% renewable energy penetration and how can this be accommodated?
- How does geographic diversity help to mitigate variability?
- How do local resources compare to remote, higher quality resources delivered by long distance transmission?
- Can balancing area cooperation mitigate variability?
- How should reserve requirements be modified to account for the variability in wind and solar?
- What is the benefit of integrating wind and solar forecasting into grid operations?
- How can hydro generation help with integration of renewables?

WWSIS and its sister study EWITS build upon a large body of work on wind integration [3-9]. Previous studies examined specific utilities or states, looking at the impact of wind on operations in the regulation (seconds to minutes), load following (minutes to hours), and unit commitment (hours to days) time frames. In these studies, hypothetical wind and transmission build-outs were typically added to the existing system, which was simulated or statistically analyzed over these time frames. These studies generally consider the impact of the variability of wind (due to varying weather) and the uncertainty of wind (due to our inability to perfectly forecast the weather). Even if the weather and the wind could be perfectly forecast,

STUDY ASSUMPTIONS

SCENARIO DEVELOPMENT:

- Specific energy targets for each of three technologies: wind, PV, and CSP were fixed. For example, wind sites could not be traded out for CSP sites.
- A number of capital cost assumptions in 2008 dollars were used in determining the different geographic scenarios: wind at $2000/kW, PV at $4000/kW, CSP with thermal storage at $4000/kW, transmission at $1600/MW-mile, and transmission losses at 1% per 100 miles. No tax credits are assumed or included.
- The geographic scenarios considered different interstate transmission build-outs and included these costs in the scenarios. Incremental intra-state transmission build-outs were not specified in this analysis. Existing transmission capacity is assumed to be unavailable for new renewable energy generation only for the scenario development process.
- New transmission was undersized: 0.7 MW of new transmission was added for each 1.0 MW of remote generation.

PRODUCTION SIMULATION ANALYSIS:

- All study results are in 2017 nominal dollars with 2% escalation per year.
- $2/MBTU coal; $9.50/MBTU natural gas.
- Carbon dioxide costs were assumed to be $30/metric ton of CO_2.
- Except in cases where specified, extensive balancing area cooperation is assumed (see box on page 19).
- The production simulation analysis assumes that all units are economically committed and dispatched while respecting existing and new transmission limits and generator cycling capabilities and minimum turndowns.
- Existing available transmission capacity is accessible to renewable generation.
- Generation equivalent to 6% of load is held as contingency reserves – half is spinning and half is non-spinning.
- The balance of generation was not optimized for renewables. Rather, a business-as-usual capacity expansion met projected load growth in 2017. Renewable energy capacity was added to this mix, so the system analyzed is overbuilt by the amount of capacity value of the renewable plants.
- Increased O&M of conventional generators due to increased ramping and cycling was not included due to lack of data.
- Renewable energy plant O&M costs are not included. Wind and solar are considered price-takers.
- The hydro modeling did not reflect the specific climatic patterns of 2004, 2005, and 2006, but rather a 10-year long term average flow per month.
- The sub-hourly modeling assumes a 5-minute economic dispatch.

grid operators would still have to accommodate wind's variability. It is important to note that operators already manage variability and uncertainty in the load; wind and solar add to that variability and uncertainty.

WWSIS was funded by DOE and was managed by NREL. The main partner in this study was WestConnect. The project team included 3TIER Group (wind power dataset, and wind and solar forecasts), State University of New York at Albany/Clean Power Research (solar radiation dataset), Exeter Associates (data collection), Northern Arizona University (wind validation and hydro), NREL (wind validation, and PV and CSP power datasets), and GE (scenarios, and main technical/economic analysis). A Technical Review Committee (TRC), composed of members of WestConnect utilities, western utility organizations, and industry and technical experts, met eight times to review technical results and progress. A broader stakeholder group, open to the public, met five times to ensure study direction and results were relevant to western grid issues. Interim and final results of this study have been vetted in approximately 30 public forums.

The study examined grid operation for the year 2017. That is, system loads and generation expansion were projected to represent year 2017. While 35% renewable energy penetration was not expected by 2017, this year was selected in order to start with a realistic model of the transmission grid. The study examined inter-annual operability by modeling operations for year 2017 three times, using historical load and weather patterns from years 2004, 2005, and 2006.

WHAT THIS STUDY DOES AND DOES NOT COVER

While this study undertakes detailed analysis and modeling of the power system, it was meant to be a complement to other in-depth studies:

- WWSIS is an operations study, not a transmission planning study, although different scenarios model different interstate transmission expansion options.
- WWSIS is not a cost-benefit analysis, even though wind and solar capital costs were incorporated in scenario development. Rather WWSIS focuses on the variable operational costs and savings due to fuel and emissions.
- WWSIS is not a reliability study, although analysis of the capacity value of wind and solar was conducted to assess their contributions to resource adequacy. A full complement of planning and operational electrical studies would be required to more accurately understand and identify system impacts.
- WWSIS does not address dynamic stability issues.
- WWSIS does not attempt to optimize the balance between wind and solar resources. Wind and solar levels were fixed independently.

In 2017, it is anticipated that WestConnect and WECC will operate differently from current practice. WWSIS assumed the following changes from current operational practice:

- Production simulations of WECC grid operations assume least-cost economic dispatch in which all generation resources are shared equally and not committed to specific loads. Except for California and Alberta, WECC currently utilizes a bilateral contract market with long and short-term contracts in which resources are contracted out to meet specific loads.
- Other than California and Alberta, WECC currently operates as 37 separate balancing areas that utilize these bilateral contracts to balance their areas. Except where specified, this study assumes five regional balancing areas in WECC (Arizona-New Mexico, Rocky Mountain, Pacific Northwest, Canada and California). WWSIS does not consider any power purchase agreements, including those for renewables[2].
- Except for California and Alberta, transmission in WECC is primarily contractually obligated and utilized. Existing available transmission capacity may be contractually obligated and not accessible to other generation. This study assumes that existing available transmission capacity is accessible to other generation on a short-term, non-firm basis.
- Pricing developed by production cost modeling can vary widely from bilateral contract prices, and was not aligned or calibrated with current bilateral contract prices. The incremental operations and maintenance (O&M) costs in the report do not necessarily replicate escalated current costs in the Western Interconnection.

In addition to these caveats, there are reasons that the study results tend toward the conservative:

- WWSIS did not model a more flexible non-renewable balance of generation than what exists and is planned in WECC today. If 20-35% variable generation were to be planned in WECC, more flexible generation would be likely planned as well, reducing the challenge that wind and solar place on operation in this study.
- This study modeled the grid for the year 2017. If WWSIS were conducted for a later year when 35% renewables would be more plausible, the power system would likely have a larger load, more flexible balance of generation, and more transmission, all of which would help to accommodate the renewables.
- The wind dataset used was conservative in terms of overestimating the actual variability found in measured wind plant output.
- The base assumption of $9.50/MBTU for gas means that gas is displaced, which leaves coal (which in the West, is less flexible than gas) to accommodate the variability of the renewables.

[2] *Thus, throughout this work, **costs** specifically and solely refer only to variable costs, i.e., fuel plus O&M plus carbon tax, that are incurred during operation. **Prices** paid to individual generators are not reported.*

SCENARIOS

WIND, SOLAR, AND LOAD DATA

About 75 GW of wind generation sites were required for the study scenarios. Because there are not adequate measurements of wind speed or wind power to model this amount of wind generation, 3TIER Group employed a mesoscale Numerical Weather Prediction (NWP) Model to essentially recreate the weather in a 3-dimensional physical representation of the atmosphere in the western U.S. for the years 2004-2006. They then sampled this model at a 2-km, 10-minute resolution and modeled wind plants throughout this region, based on a Vestas V90 3-MW turbine. 3TIER Group also developed day-ahead wind forecasts for each hour. Over 960 GW of wind sites were modeled. The wind dataset is publicly available [10, 11].

Similarly, a lack of solar irradiance or power measurements led to the use of a satellite cloud cover model to simulate the United States at a 10-km, hourly resolution [12]. Day-ahead hourly solar forecasts were also developed [10]. PV was modeled in 100-MW blocks as distributed generation on rooftops because modeling information for large, central station PV plants was not available at the time of the study. Over 15 GW of PV plants were included in the dataset. Ten-minute variability was subsequently added to the aggregate hourly outputs to create the 10-minute PV data.

CSP was modeled as 100-MW blocks of parabolic trough plants with six hours of thermal storage. Over 200 GW of CSP plants were modeled in the dataset. Because the CSP with thermal storage produces a very stable output, the 10-minute dataset was created simply by interpolating the hourly dataset.

Hourly load-profile data for all operating areas in WECC were obtained from a Ventyx database, and 10-minute load data were derived by interpolating the hourly data.

SCENARIO DESCRIPTION

The WWSIS used a multidimensional scenario-based study approach to evaluate:

- Different levels of energy penetration for wind and solar generation, ranging from 11% to 35%;
- Different geographic locations for the wind and solar resources;
- A wide array of sensitivities to assess issues such as fuel costs, operating reserve levels, unit commitment strategies, storage alternatives, balancing area size, etc.

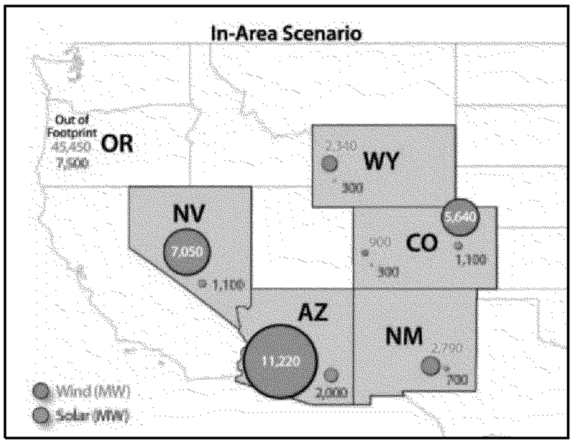
Table 1 shows the four levels of wind and solar energy penetration assumed for the study scenarios. The **Preselected case** includes that wind and solar capacity which was installed by the end of 2008. The **10% case** includes 10% wind energy (relative to total annual load energy) and 1% solar energy (solar consisted of 70% CSP and 30% PV) in the study footprint, as well as the rest of WECC. The **20% case** includes 20% wind energy and 3% solar energy in the study footprint, with 10% wind energy and 1% solar energy in the rest of WECC. The **20/20% case** includes 20% wind energy and 3% solar energy in the study footprint, as well as the rest of WECC. The **30% case** included 30% wind energy and 5% solar energy in the study footprint, with 20% wind energy and 3% solar energy in the rest of WECC.

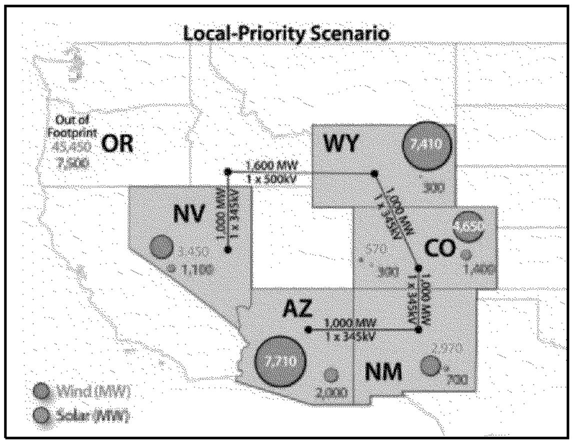
TABLE 1 – WIND AND SOLAR ENERGY PENETRATIONS FOR WWSIS CASES WITH NAMING CONVENTION IN BLUE.

CASE NAME	IN FOOTPRINT			REST OF WECC	
NAME	WIND + SOLAR	WIND	SOLAR	WIND	SOLAR
PRE-SELECTED CASE	3%*	3%	*	2%	*
10% CASE	11%	10%	1%	10%	1%
20% CASE	23%	20%	3%	10%	1%
20/20% CASE	23%	20%	3%	20%	3%
30% CASE	35%	30%	5%	20%	3%

Existing solar embedded in load

Three geographic scenarios were developed to examine the tradeoff between: 1) local resources that are closer to load, but have lower capacity factors and 2) remote resources that have higher capacity factors, but require long distance transmission to access loads. An algorithm was developed to select sites based on energy value, capacity value, and geographic diversity according to criteria developed for each scenario. Figure 1 shows maps of the study scenarios for the 30% case. Total nameplate ratings of wind generation for each state are shown in blue; solar MW ratings are shown in red. New transmission lines to increase interstate transfer capability are shown in black. Significant intra-state transmission also needs to be built to bring the renewable resources to the existing bulk transmission grid, but WWSIS did not examine intra-state transmission.





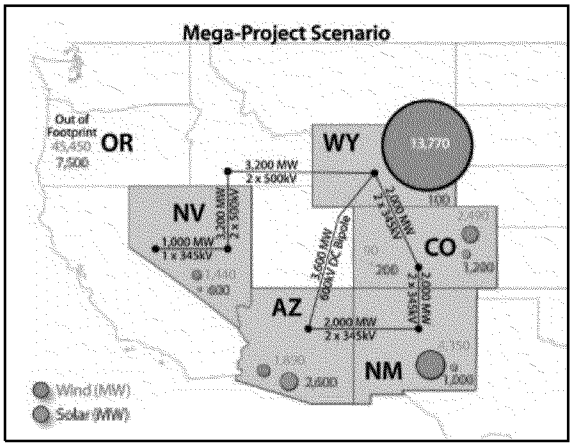


Figure 1 – Three geographic scenarios developed for siting of wind and solar plants in the 30% case, with appropriate interstate transmission included to bring resources to load.

In Area Scenario: Each state in the study footprint met its wind and solar energy targets using the best available wind and solar generation resources within its state boundary. No additional interstate transmission was added.

Local Priority Scenario: This scenario used the best wind and solar sites within the entire footprint, but included a 10% capital cost advantage to resources within each state. The result was a scenario that was about halfway between the In Area and Mega Project Scenarios. This scenario includes new interstate transmission, but not as much as the Mega Project Scenario.

Mega Project Scenario: The study footprint met its wind and solar energy targets by using the best available wind and solar resources within the study footprint. Given that many of the best wind resources are in Wyoming, this scenario includes a large penetration of wind generation in Wyoming (and other wind-rich areas), with new transmission lines to deliver the energy to load centers.

For all three of these scenarios, the rest-of-WECC scenario remains constant: each state in the rest of WECC meets its renewable energy target using the best available resources within the state boundary.

Table 2 shows a summary of the total wind and solar MW ratings by state for the three study scenarios. Table 3 summarizes the capital costs for the three study scenarios.

TABLE 2 – SUMMARY OF AGGREGATED WIND AND SOLAR MW RATINGS BY STATE FOR WWSIS SCENARIOS								
IN AREA								
			10%	1%	20%	3%	30%	5%
AREA	LOAD MIN. (MW)	LOAD MAX. (MW)	WIND (MW)	SOLAR (MW)	WIND (MW)	SOLAR (MW)	WIND (MW)	SOLAR (MW)
ARIZONA	6,995	23,051	3,600	400	7,350	1,200	11,220	2,000
COLORADO EAST	4,493	11,589	2,040	300	3,780	800	5,640	1,400
COLORADO WEST	712	1,526	300	0	600	200	900	300
NEW MEXICO	2,571	5,320	1,080	200	1,920	400	2,790	700
NEVADA	3,863	12,584	2,340	200	4,680	700	7,050	1,100
WYOMING	2,369	4,016	930	100	1,620	100	2,340	300
IN FOOTPRINT	**21,249**	**58,087**	**10,290**	**1,200**	**19,950**	**3,400**	**29,940**	**5,800**
LOCAL PRIORITY								
			10%	1%	20%	3%	30%	5%
AREA	LOAD MIN. (MW)	LOAD MAX. (MW)	WIND (MW)	SOLAR (MW)	WIND (MW)	SOLAR (MW)	WIND (MW)	SOLAR (MW)
ARIZONA	6,995	23,051	2,850	400	5,2550	1,200	7,710	2,000
COLORADO EAST	4,493	11,589	2,190	300	3,870	800	4,650	1,400
COLORADO WEST	712	1,526	210	0	450	200	570	300
NEW MEXICO	2,571	5,320	1,350	200	2,100	400	2,970	700
NEVADA	3,863	12,584	1,350	200	2,490	700	3,450	1,100
WYOMING	2,369	4,016	1,650	100	4,020	100	7,410	300
IN FOOTPRINT	**21,249**	**58,087**	**9,600**	**1,200**	**18,180**	**3,400**	**26,760**	**5,800**
MEGA PROJECT								
			10%	1%	20%	3%	30%	5%
AREA	LOAD MIN. (MW)	LOAD MAX. (MW)	WIND (MW)	SOLAR (MW)	WIND (MW)	SOLAR (MW)	WIND (MW)	SOLAR (MW)
ARIZONA	6,995	23,051	810	400	1,260	1,200	1,890	2,600
COLORADO EAST	4,493	11,589	2,010	300	2,400	800	2,490	1,200
COLORADO WEST	712	1,526	60	0	90	200	90	200
NEW MEXICO	2,571	5,320	1,860	200	2,700	400	4,350	1,000
NEVADA	3,863	12,584	570	200	1,020	700	1,440	600
WYOMING	2,369	4,016	3,390	100	8,790	100	13,770	100
IN FOOTPRINT	**21,249**	**58,087**	**8,700**	**1,200**	**16,260**	**3,400**	**24,030**	**5,700**
			10%	1%	20%	3%	30%	5%
OUT OF FOOT-PRINT	**46,328**	**119,696**	**22,950**	**2,500**	**22,950**	**2,500**	**45,450**	**7,500**

TABLE 3 – CAPITAL COSTS (IN US2008$) FOR STUDY SCENARIOS WITH 30% WIND ENERGY AND 5% SOLAR ENERGY IN THE STUDY FOOTPRINT.							
SCENARIO	WIND (MW)	SOLAR (MW)	TRANSMISSION (GW-MI)	WIND ($B)	SOLAR ($B)	INTERSTATE TRANSMISSION ($B)	TOTAL ($B)
IN-AREA	29,940	5,800	0	59.9	23.2	0	83.1
LOCAL PRIORITY	26,760	5,800	2,100	53.5	23.2	3.4	80.1
MEGA PROJECT	24,030	5,700	6,900	48.1	22.8	11.0	81.9

The rest of WECC includes 45,450 MW of wind ($91 billion), 4000 MW of PV ($16 billion), and 3500 MW of CSP ($14 billion). Intrastate transmission is not included in any of these scenario costs.

ANALYTICAL METHODS

Four primary analytical methods were used to evaluate the performance of the system with high penetrations of wind and solar generation: statistical analysis, hourly production simulation analysis, sub-hourly analysis using minute-to-minute simulations, and resource adequacy analysis.

Statistical analysis was used to quantify variability due to system load, as well as wind and solar generation over multiple time frames (annual, seasonal, daily, hourly, and 10-minute). The statistical analysis quantified the grid variability due to load alone over several time scales, using the interpolated hourly load data. The changes in grid variability due to wind and solar generation were also quantified for each scenario at various levels of aggregation. The statistical analysis also examined the forecast accuracy for wind generation.

Production simulation analysis with GE s MAPS (Multi-Area Production Simulation) program was used to evaluate hour-by-hour grid operation of each scenario for 3 years with different wind, solar, and load profiles. WECC was represented as a set of 106 zones, each with its own load profile, portfolio of generating plants, and transmission capacity with neighboring areas. The zones were grouped into 20 transmission areas. The production simulation results quantified numerous impacts of additional renewable generation on grid operation including:

- Amount of flexible generation on-line during a given hour, including its available ramp-up and ramp-down capability;
- Effects of day-ahead wind forecast alternatives in unit commitment;
- Changes in conventional generation dispatch;
- Changes in emissions (NO_x, SO_x, and CO_2) due to renewable generation;
- Changes in grid operation costs, revenues, and net cost of energy;
- Changes in transmission path loadings;
- Changes in use of hydro resources;
- Changes in use and economic value of energy storage.

Minute-to-minute simulation analysis was used to quantify grid performance trends and to investigate potential mitigation measures during challenging situations, such as large 1-hour, 3-hour and 6-hour changes in net load, high levels of wind and solar penetration, low load levels with minimal maneuverable generation on-line, and/or high wind forecast errors. Minute-to-minute analysis simulated the operation of dispatchable generation resources as well as variable wind and solar generation in the study footprint using one-minute time steps, while enforcing constraints related to unit maximum, minimum, ramp rate, intertie flow schedule, and regional Automatic Generator Control (AGC) functions.

Resource adequacy analysis involved loss-of-load-expectation (LOLE) calculations for the study footprint using the Multi-Area Reliability Simulation program, MARS. The analysis quantified the impact of wind and solar generation on overall reliability measures, as well as the capacity values of the wind and solar generation resources.

Impacts on system-level operating reserves were also analyzed using a variety of techniques including statistics, production simulation, and minute-to-minute simulation. This analysis quantified the effects of variability and uncertainty, and related that information to the system s increased need for operating reserves to maintain reliability and security.

The results from these analytical methods complemented each other, and provided a basis for developing observations, conclusions, and recommendations with respect to the successful integration of wind and solar generation into the WestConnect grid.

OPERATIONS WITH 35% RENEWABLES

The power system is designed to handle variability in load. With wind and solar, the power system is called on to handle variability in the net load (load minus wind minus solar), which can be considerable during certain periods of the year. Figure 2 shows the load, wind, solar, and net load profiles for the 30% case during two selected weeks in July and April. In the July week, (top plot), the net load (blue line at bottom edge) is not significantly impacted by wind and solar variation. However, in the April week (bottom plot), the high, variable wind output dominates the net load, especially during low load hours, leading to several hours of negative net load during the week. This week in April was the worst week in terms of operational challenges of the three years.

WWSIS finds that 35% renewable energy penetration is operationally feasible provided significant changes to current operating practice are made, including balancing area cooperation and sub-hourly generation and interchange schedule.

As an example of how the system would operate under less severe operating conditions, Figure 3 shows the generation dispatch for the same July week shown in Figure 2 for the In-Area Scenario. The left figure is without renewable generation and the right is the 30% case. Although the wind and solar generation are definitely noticeable, they primarily displace combined cycle and gas turbine generation, and have minimal impact on the steam coal units.

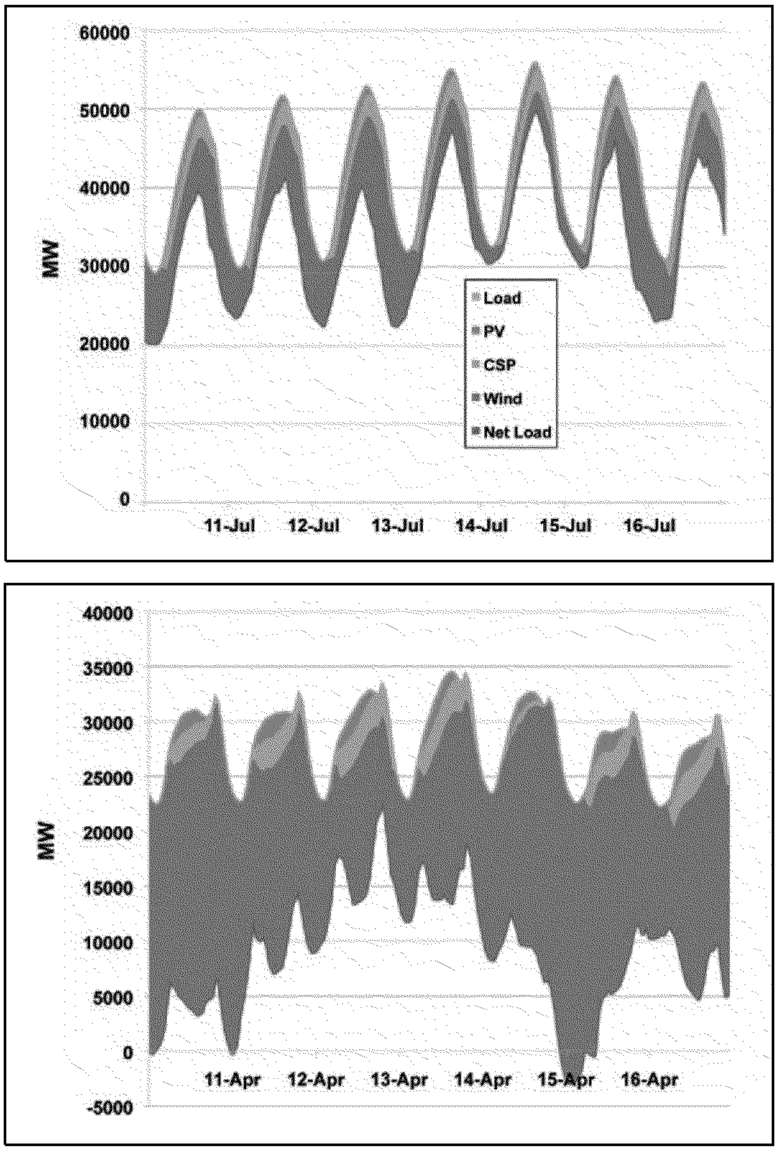


Figure 2 – With 35% renewables, system operators must now balance generation against the net load (blue) line. This may be straightforward (top, July) or challenging (bottom, April).

Figure 4 shows similar information for the April week shown in Figure 2. Here, operating the system with renewable generation is much more challenging. The combined cycle generation has been almost completely displaced, as have significant levels of coal generation. Nonetheless, the system can operate with balancing area cooperation. Without balancing area cooperation, operations during this week would be extremely difficult, if not impossible, for individual balancing areas.

How much renewable generation can the system handle? All three geographic scenarios show significant benefits with no negative effects in the 10% case. No significant adverse impacts were observed up to the 20% case in WestConnect, given balancing area cooperation. Increased renewable generation in the rest of WECC

[3] *WECC requires 6% of load to be held as contingency reserves, half of which is required to be spinning (i.e., synchronized to the grid) reserves.*

(20/20% case) led to increased stress on system operations within WestConnect, with some instances of insufficient reserves[3] due to wind and solar forecast error. These can be addressed, but the system has to work harder to absorb the renewables. Operations become more challenging for the 30% case in which load and contingency reserves are met only if the wind/solar forecasts are perfect. With imperfect forecasts, load is served but there are contingency reserve shortfalls. Extra spinning reserves can be held every hour of the year to meet those contingency reserve requirements, but the cost to hold enough to eliminate all contingency reserve shortfalls is very high. A more cost-effective alternative is to establish a demand response program or develop strategies to more accurately predict when these shortfalls occur and schedule more reserves during those hours or add additional quick start generation where needed. In the 20% and 30% cases, decreased flexibility of either the coal or hydro facilities made operation more difficult and increased the costs of integrating renewable generation.

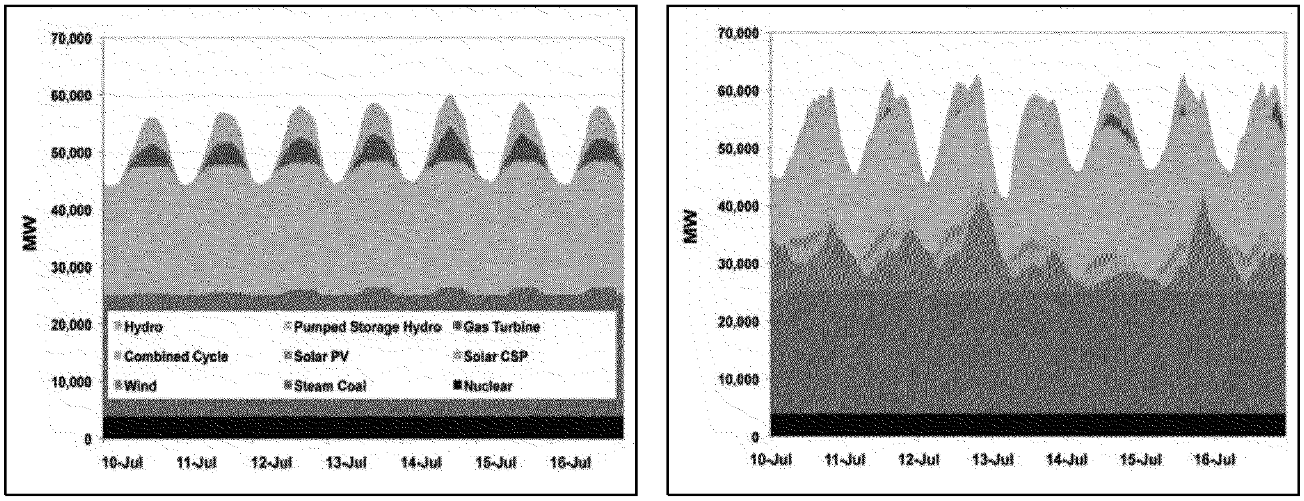


Figure 3 – 35% renewables have a minor impact on other generators during an easy week in July, 2006. *WestConnect dispatch - no renewables (left) and 30% case (right)*

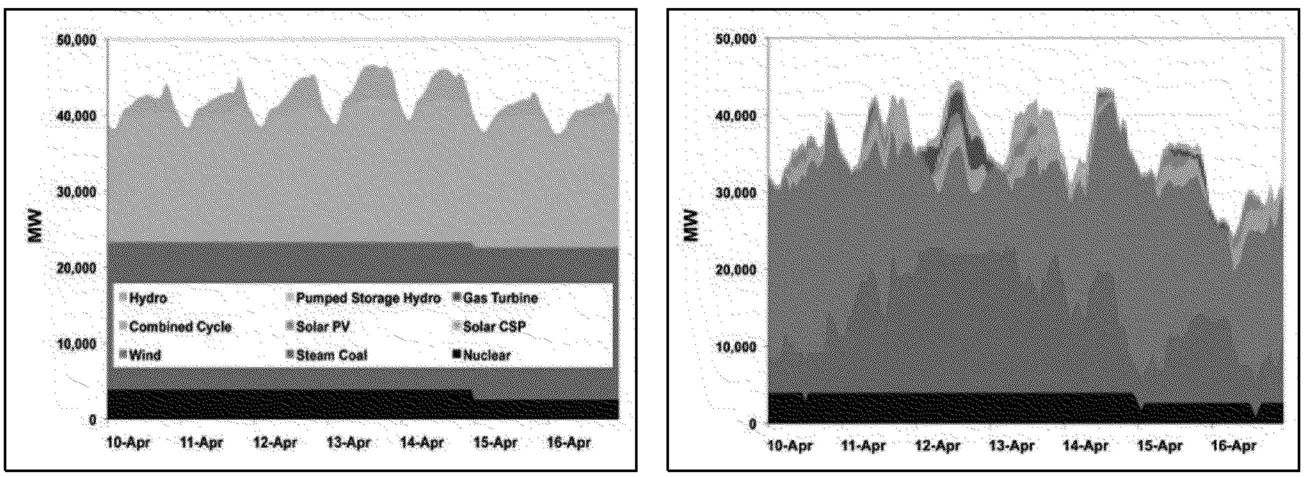


Figure 4 – 35% renewables have a significant impact on other generation during the hardest week of the three years (mid-April 2006). *WestConnect dispatch - no renewables (left) and 30% case (right)*

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BENEFITS OF 35% RENEWABLES

Wind and solar generation primarily displace gas resources nearly all hours of the year, given the fuel prices and carbon tax assumed for this study ($2/MBTU coal, $9.50/MBTU gas, $30/ton CO_2). Since gas-fired generation is typically more flexible than coal generation, the natural economic displacement of gas generation by wind and solar generation makes the balance of dispatchable generation on-line less flexible (fewer gas units, more coal units). Across WECC, operating costs drop by $20 billion/yr ($17 billion/yr in 2009$) from approx $50 billion/yr ($43 billion/yr in 2009$), resulting in a 40% savings due to offset fuel and emissions. This savings does not account for the capital or operating costs associated with the wind, solar, or transmission facilities, nor does it include any of the costs that would be required to implement the operational reforms needed to accommodate the renewables including balancing area cooperation or sub-hourly scheduling, although presumably some of this savings would be used to recover the capital costs of building this scenario, including payments to wind and solar generators. Figure 5 (left plot) shows the overall impact on the operating costs of WECC for the various penetration levels under the In-Area Scenario with a state-of-the-art (SOA) forecast. The 30% case shows WECC operating cost savings of $20 billion/yr ($17 billion/yr in 2009$) due to the wind and solar generation resources. Figure 5 (right plot) divides these values by the corresponding amount of renewable energy provided. In the 30% case, this equates to $80/MWh ($60/MWh in 2009$) of wind and solar energy produced. Lower penetrations of renewables showed values up to $88/MWh ($75/MWh in 2009$) of renewable energy produced (see Section 6.2). These operating cost savings would be applied toward the costs of the wind and solar energy, and depending on the magnitude of these costs, may or may not be sufficient to cover them.

> The 30% case reduced fuel and emissions costs by 40% and CO_2 emissions by 25-45% across WECC.

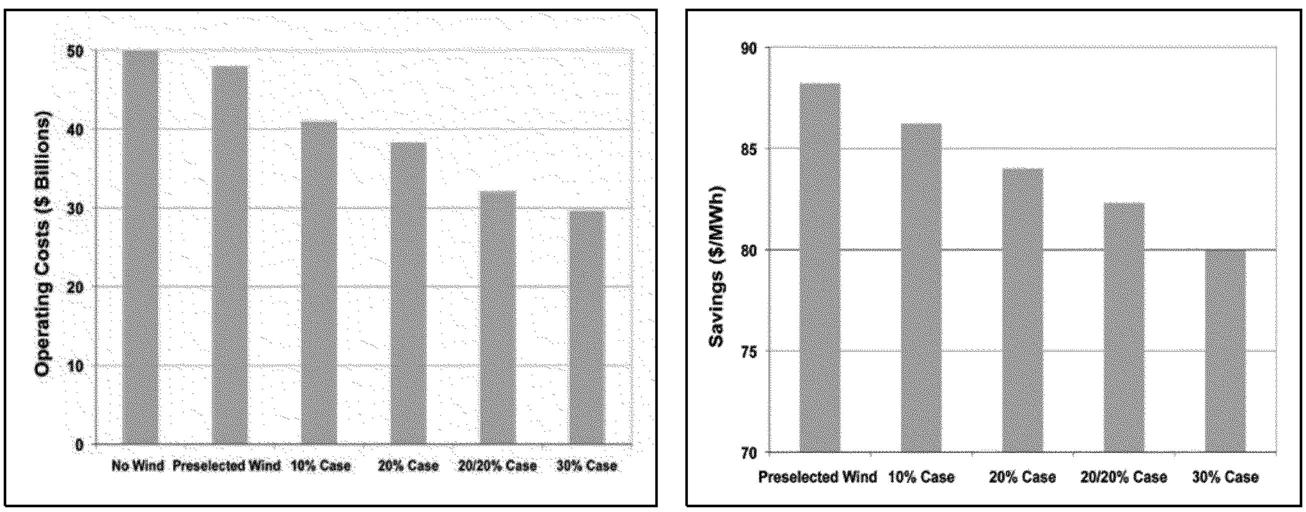


Figure 5 – WECC saves $20 billion ($17 billion in 2009$), or 40%, in annual operating costs in the 30% case, which is equivalent to $80 ($60 in 2009$) per MWh of wind and solar energy produced. *Note: Chart on right starts at $70/MWh.*

At a \$3.50/MBTU gas price, wind and solar primarily displace coal generation, leaving the more flexible gas generation resources to operate together with the wind and solar generation. With lower gas price assumptions, operating costs are reduced by about 40%, to \$46/MWh (\$39/MWh in 2009\$), but emissions reductions are higher.

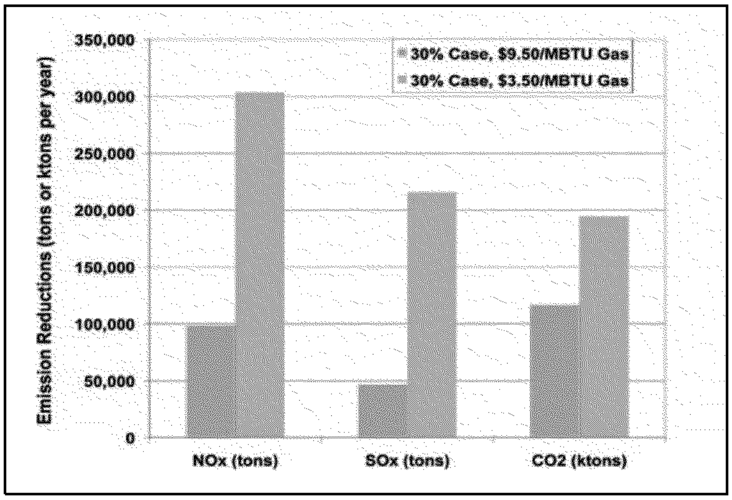


Figure 6 –Assuming \$9.50/MBTU gas, renewable energy displaces gas (orange). At lower gas prices (\$3.50/MBTU), coal is displaced instead, resulting in greater emissions reductions (blue).

Figure 6 shows the total WECC reductions in emissions for the 30% case. CO_2 emissions would be reduced by nearly 120 million tons/year, or approximately 25%, for the 30% case. SO_x emissions would be reduced by approximately 45,000 tons/year (~5%) and NO_x would be reduced nearly 100,000 tons/year (~15%) (see Section 6.2.1). At a \$3.50/MBTU gas price, CO_2 emissions are reduced by nearly 200 million tons/year (45%), and NO_x and SO_x by 300,000 tons/year (50%) and 220,000 tons/year (30%), respectively.

BALANCING AREA COOPERATION IS ESSENTIAL

There are three key benefits of balancing area cooperation: 1) aggregating diverse renewable resources over larger geographic areas reduces the overall variability of the renewables, 2) aggregating the load reduces the overall variability of the load, and 3) aggregating the non-renewable balance of generation provides access to more balancing (and more flexible) resources. Figure 7 shows the reduced-variability benefit arising from aggregating smaller transmission areas into the WestConnect footprint. Variability for small areas such as Colorado-West (CO-W) or Wyoming (WY) increases significantly as renewable penetrations increase from the 10% to the 30% case This effect becomes even more extreme at a more granular level, e.g., for specific balancing areas within

> The technical analysis performed in this study shows that it is feasible for the WestConnect region to accommodate 30% wind and 5% solar energy penetration, but it would require extensive balancing area cooperation or consolidation, real or virtual.

a state (see Section 7.1). However, when the balancing areas across WestConnect are aggregated, there is only a slight increase in variability with increased renewables penetrations, and even a slight decrease in variability WECC-wide.

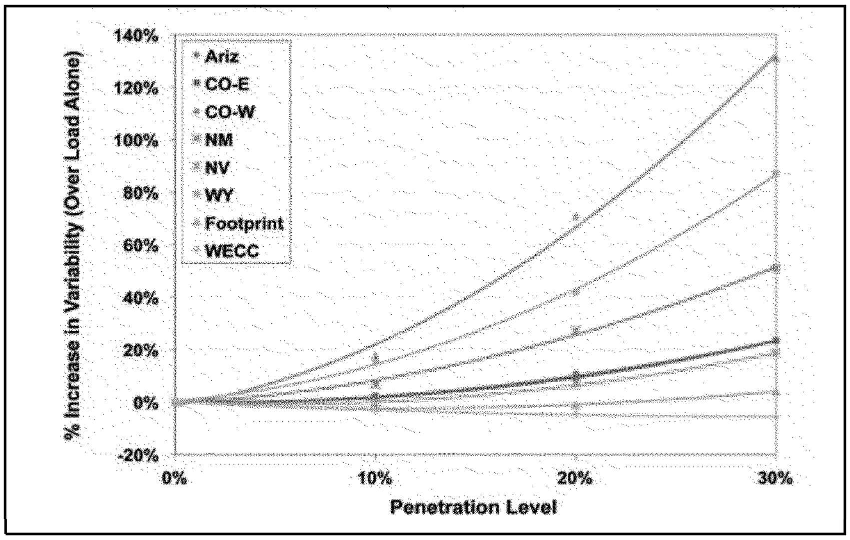


Figure 7 – The variability of the net load increases with increasing renewable energy penetration. Aggregating several transmission areas over the WestConnect footprint results in reduced variability. *Percent increase in the standard deviation of the hourly changes of the net load in all areas for In-Area Scenario.*

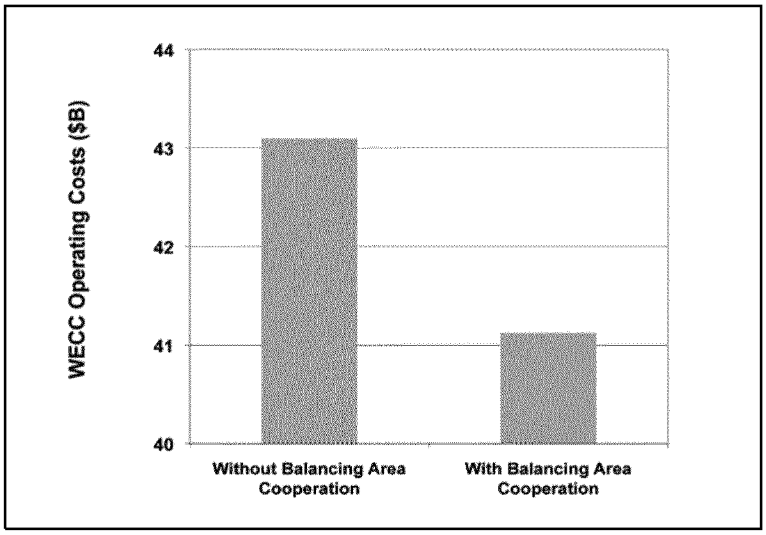


Figure 8 – WECC can save $2 billion ($1.7 billion in 2009$) by holding spinning reserves as 5 large regions (right) rather than many smaller zones (left).

From an operational perspective, balancing area cooperation can lead to cost savings because reserves can be pooled. A sensitivity analysis was performed, running WECC as 106 zones (which are roughly equivalent to balancing areas in the southwest, but there are multiple zones per balancing area in the northwest) versus 5 large regions.

Balancing area (BA) cooperation can take many forms and means different things to different people. In WWSIS, cooperation is modeled by assuming:

- All generation resources, across all BAs, are committed from a common regional generation stack on a least-cost basis
- Generation commitments assume physical transmission capability is available for import or export of power transfers between BAs
- All generation dispatches are made on a least–marginal-cost basis
- All regional reserves are shared across BAs; i.e., the most economic resources for reserves are used
- Day-ahead generation dispatch and inter-area transmission schedules can be modified during operation to enable sharing of load-following, regulation, and reserves

Mechanisms to enable these aspects of cooperation are numerous, and include facets currently used or proposed in WECC such as the ACE diversity interchange (ADI), dynamic scheduling, an energy imbalance service, and other means of consolidating BA services. Many technical and institutional barriers will need to be addressed to achieve the level of cooperation of the work presented here.

Figure 8 shows the $2 billion ($1.7 billion in 2009$) savings in WECC operating costs in the 10% case. There are significant savings from sharing reserves over larger regions, irrespective of the renewables on the system.

SUB-HOURLY SCHEDULING IS CRITICAL

The current practice of scheduling both the generation and interstate exchange only once each hour has a significant impact on the regulation duty. At high penetration levels, such hourly schedule changes can use most, if not all, of the available regulation capability to compensate for Area Control Error (ACE) excursions during large scheduled ramps. This can leave no regulation capability for the sub-hourly variability.

The minute-to-minute simulations showed that the current practice of hourly scheduling has a greater impact on the regulation requirements than does the wind and solar variability.

Sub-hourly scheduling will be required to successfully operate the system at high penetration levels without significantly increased regulating reserves.

Sub-hourly scheduling can substantially reduce the maneuvering duty imposed on the units providing load following. In the 30% case, the fast maneuvering of combined cycle plants with sub-hourly scheduling is about half of that with hourly scheduling, as shown in Figure 9. Sub-hourly scheduling in the 30% case is roughly equivalent to the 20/20% case with hourly scheduling. Improvements in plant efficiency and reductions in O&M costs, while difficult to quantify, are expected from this smoother operation.

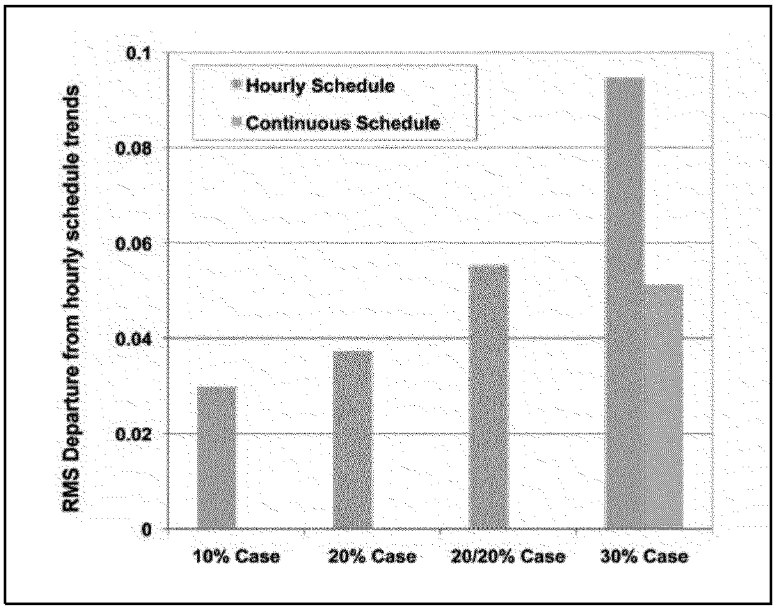
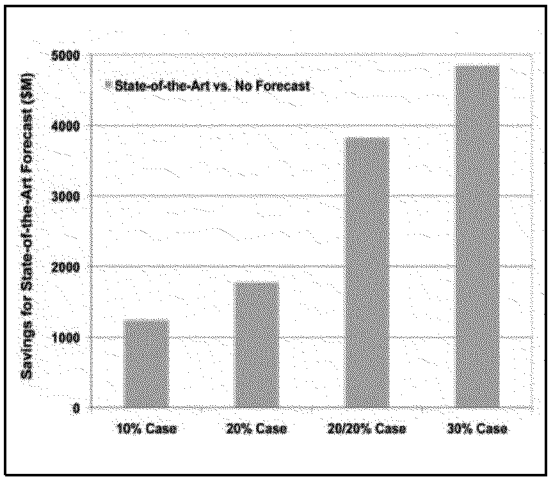


Figure 9 – Fast maneuvering duty of combined cycle units can be cut in half by moving from hourly to sub-hourly scheduling.

UNCERTAINTY (FORECAST ERROR) RESULTS IN THE BIGGEST IMPACT ON THE SYSTEM

Integrating day-ahead wind and solar forecasts into the unit commitment process is essential to help mitigate the uncertainty of wind and solar generation. Even though SOA wind and solar forecasts are imperfect and sometimes result in reserve shortfalls due to missed forecasts, it is still beneficial to incorporate them into the day-ahead scheduling process, because this will reduce the amount of shortfalls. Over the course of the year, use of these forecasts reduces WECC operating costs by up to 14%, or $5 billion/yr ($4 billion/yr in 2009$), which is $12-20/MWh ($10-17/MWh in 2009$) of wind and solar generation. The left side of Figure 10 shows the WECC-wide operating cost savings for using SOA forecasts compared to ignoring wind in the day-ahead commitment. The right side shows the incremental cost savings for perfect wind and solar day-ahead forecasts, which would reduce WECC operating costs by another $500 million/yr ($425 million/yr in 2009$) in the 30% case (see Section 6.2.1), or $1-2/MWh ($0.9-1.7/MWh in 2009$) of wind and solar generation.

> Using state-of-the-art wind and solar forecasts in day-ahead unit commitment is essential and would reduce annual WECC operating costs by up to $5 billion ($4 billion in 2009$) or $12-20/MWh ($10-17/MWh in 2009$) of renewable energy, compared to ignoring renewables in the unit commitment process. Perfect forecasts would reduce annual costs by another $500 million ($425 million in 2009$) or $1-2/MWh ($0.9-$1.7/MWh in 2009$) of renewable energy.



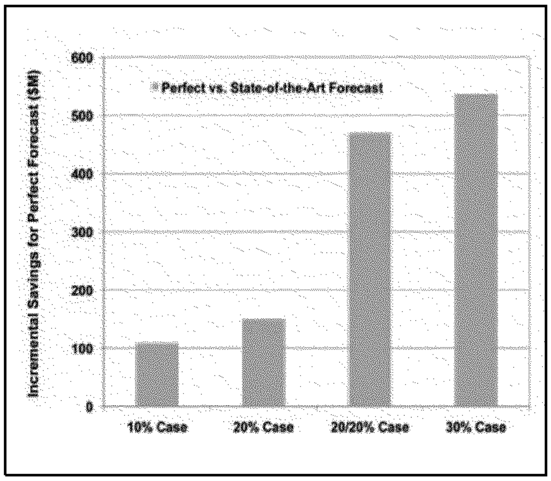


Figure 10 – WECC saves $1-5 billion ($1-4 billion in 2009$) in annual operating costs just by using a SOA day-ahead forecast in the unit commitment process (left). Incremental savings for perfect forecasts are an order of magnitude less (right).

THE IMPACTS OF EXTREME FORECAST ERRORS ON CONTINGENCY RESERVE SHORTFALLS

While on average, wind forecast error is not very large (8% mean absolute error across WestConnect), there are hours when wind forecast errors can be extreme, ranging up to over 11,000 MW of over- or under-forecast in WestConnect. Severe over-forecasts can result in contingency reserve shortfalls; severe under-forecasts can result in curtailment of wind.

Operating rules dictate that systems must carry contingency reserves to cover system events, such as tripping of a large generator. In WECC, the spinning portion of these contingency reserves is equivalent to 3% of the system load. Applying these WECC rules, severe over-forecasts can lead to under-commitment of generation units, which can result in contingency reserve shortfalls if insufficient quick-start capacity is available.

If the forecast is perfect, there are no contingency reserve shortfalls, even in the 30% case. With a SOA forecast, Figure 11 shows that these contingency reserve shortfalls become an issue in the 30% case. It should be noted, however, that even these shortfalls represent only a tiny percentage (~0.005%) of the total load energy.

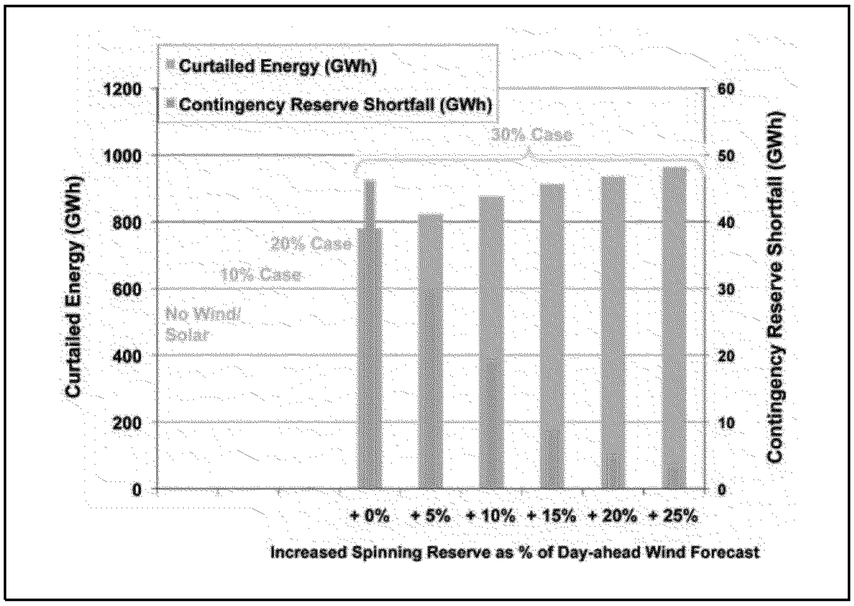


Figure 11 – Contingency reserve shortfalls start to become an issue in the 30% case. Increasing spinning reserve can reduce the shortfalls but even increasing spinning reserves by 25% of the day-ahead wind forecast does not completely eliminate reserve shortfalls.
Hourly production simulation analysis shows spilled energy, or curtailment, on the left axis and contingency reserve shortfalls on the right axis for the In-Area Scenario with no wind/solar, the 10, 20, and 30% case for a SOA forecast. The five bars on the right show the effect of increasing spinning reserve by 5, 10, 15, 20, and 25% of the day-ahead wind forecast.

Spinning reserves can be increased to cover these contingency reserve shortfalls, but at a cost. Figure 11 shows the impact of increasing spinning reserves by 5, 10, 15, 20 and 25% of the day-ahead wind forecast. However, each additional 5% increment of committed spinning reserve is increasingly expensive, as shown in Figure 12, and even with a 25% increase in committed spinning reserves, not all contingency reserve shortfalls are eliminated.

The average cost of increasing reserves is shown in Figure 12. Increasing the committed spinning reserve by 5% of the wind forecast increases WECC operating costs by over $3,000 per MWh ($2,550/MWh in 2009$) of reduced reserve shortfall. Expressed another way, it would be comparable to pay some of the load $3,000/MWh ($2,550/MWh in 2009$) to drop off rather than increasing the spinning reserve by 5% of the forecast. At the other extreme, if spinning reserve is increased by 25%, it would cost an average of roughly $13,600/MWh ($11,600/MWh in 2009$) of reserve shortfall. The incremental reduction achieved by increasing the spinning reserve from 20% to 25% of the forecast would cost over $100,000/MWh ($85,000/MWh in 2009$). It should

It is more cost-effective to have demand response address the 89 hours of contingency reserve shortfalls rather than increase spin for 8760 hours of the year. Demand response can save up to $600M/yr ($510M/yr in 2009$) in operating costs versus committing additional spinning reserves.

be more economic to use load participation (i.e., demand response) than to increase the spinning reserves to achieve the same objectives. Using load participation instead of committing additional generation for operating reserves would save up to $600 million ($510 million in 2009$) in operating costs per year (see Sections 5.4, 7.2, and 6.2.2).

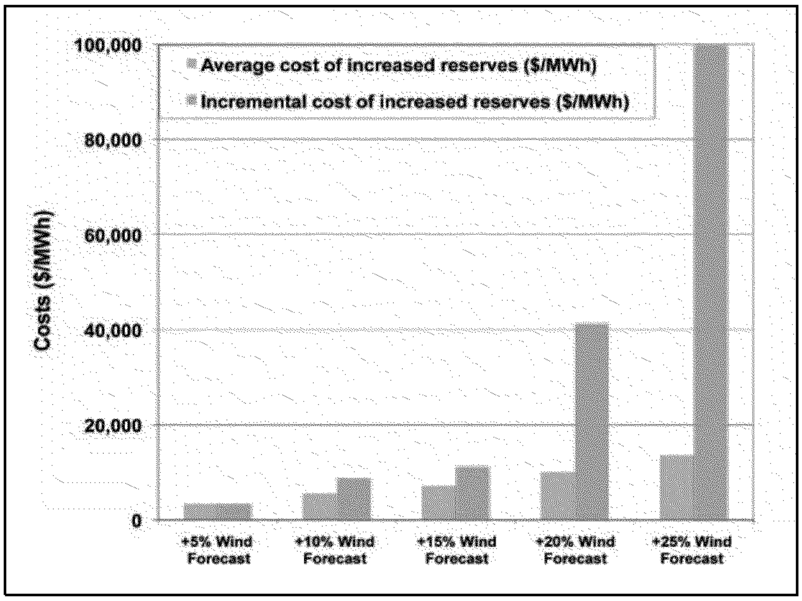


Figure 12 – The cost of increasing spinning reserves increases with higher percentages of spin. The incremental cost increases sharply at higher percentages of spin, indicating that the cost of reducing those final reserve shortfalls is prohibitively high. *The five bars show the effect of increasing spinning reserve by 5, 10, 15, 20, and 25% of the day-ahead wind forecast.*

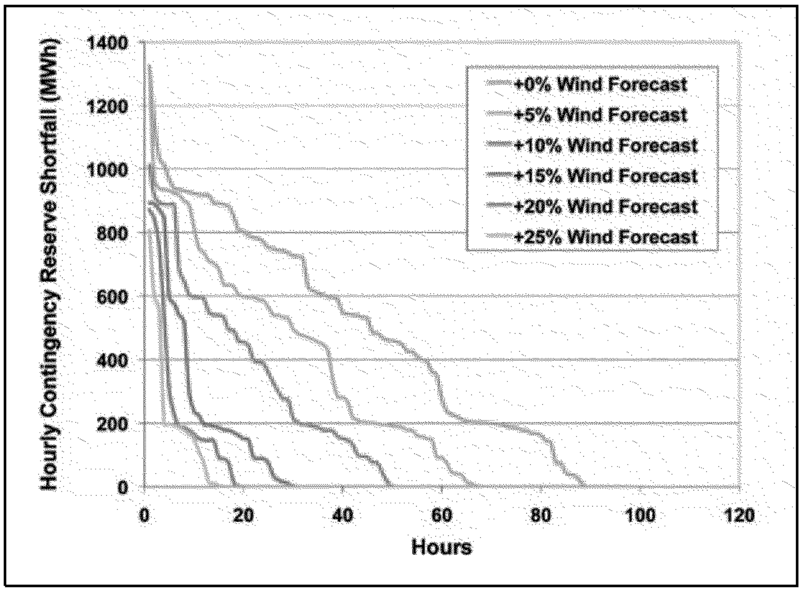


Figure 13 – A demand response program which requires load to participate in the 89 hours of the year that there are contingency reserve shortfalls is more cost-effective than increasing spin for each of the 8760 hours of the year. *Hourly contingency reserve-shortfall duration curves for the In-Area 30% case with a SOA forecast with no additional spinning reserves, and then with spinning reserves increased by 5, 10, 15, 20, and 25% of the day-ahead wind forecast.*

Instead of holding additional spinning reserve for each of the 8760 hours of the year, Figure 13 shows that a demand response program could address those 89 hours of the year when there is a contingency reserve shortfall and have a total participation of approximately 1300 MW of load. The contingency reserve shortfalls could also be met by a combination of increased spinning reserves and a smaller demand response program. An alternative to demand response or increased spinning reserve for every hour of the year could be dynamic allocation of spinning reserves based on better forecasting, improved reserve policies, and more accurate prediction of when shortfalls are likely to occur.

HOW OFTEN IS WIND CURTAILED?

Uncertainty drives both curtailment and reserve shortfalls. With a perfect forecast, no wind or solar curtailment was necessary in any of the scenarios. Even in the few hours when the renewable generation exceeded the load in WestConnect, there was sufficient flexibility within WECC to absorb all of the generation. With a SOA forecast, no curtailment occurred up through the 20% case (see Figure 11). The hourly production simulations showed about 800 GWh of wind curtailment in the 30% case, representing less than 0.5% of the total wind energy production. In addition, the minute-to-minute analysis indicated that more wind curtailment may be required under some combinations of low load and high wind. Altogether, wind curtailment in the 30% case is estimated to be on the order of 1% or less of the total wind energy. Curtailment is also affected by flexibility of the balance of generation, e.g., raising the minimum operating point of the coal units to 70% increased the wind curtailment slightly (see Sections 6.2 and 6.4.4).

THE EFFECT OF VARIABILITY – ARE ADDITIONAL RESERVES NECESSARY?

In addition to contingency reserves, utilities are required to hold variability or load following reserves to cover 10-minute load variability 95% of the time. Typically, utilities do not commit additional variability reserves because the existing dispatchable generating fleet can adequately cover this variability reserve requirement. With wind and solar, the net load variability increases and in the 30% case, the average variability reserve requirement doubles. However, when wind and solar are added to the system, thermal units are backed down because it is sometimes more economical to back down a unit rather than to decommit it. This results in more up-reserves available than in the case when there is no wind and solar, as shown in Figure 14. Therefore, commitment of additional reserves is not needed to cover variability in the study footprint. Figure 14 shows a duration curve of the total amount of up-reserves in the committed generation after the contingency reserve requirement is subtracted out, showing that 95% of the time, there are adequate up-reserves in the 30% Local Priority case.

> **While the need for variability reserves doubles in the 30% wind case, the backing down of conventional units results in more available up-reserves. Therefore, commitment of additional reserves is not needed to cover the increased variability.**

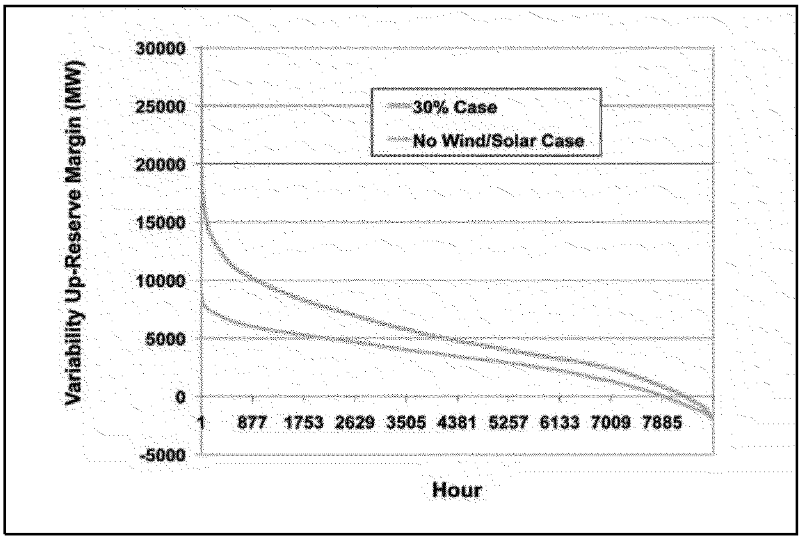


Figure 14 – There are more up-reserves available in the 30% case than in the no wind/solar case because the additional renewable energy generation causes many conventional units to be backed down. *Variability Up-Reserve Margin – Local Priority 30% vs. No Wind or Solar Case.*

Regulating reserves are a subset of the fast variability requirement, but are held separately from the 10-minute variability reserves. Regulating reserves are required to be automatically controlled through AGC. While WWSIS did not evaluate which units were on AGC, the minute-to-minute analysis showed that sufficient regulating reserve capability was available in WestConnect.

Down reserves can be handled through wind curtailment when other resources are depleted. A wind plant can reduce its output very quickly in response to a command signal. Simulations in this study show that down reserves can be implemented through command signals (ACE signals) from system operators. With extensive balancing area cooperation, WestConnect can accommodate large amounts of renewables, and curtailment of wind is expected to be on the order of 1% or less in the 30% case.

Wind plants can be curtailed to provide down regulating reserves instead of moving regulating units. Even so, curtailment is estimated to be on the order of 1% or less of total wind energy in the 30% case.

WHAT IS THE EFFECT OF DIFFERENT TRANSMISSION AND GEOGRAPHIC SCENARIOS?

The In-Area, Local Priority, and Mega Project Scenarios showed similar overall performance and economics for a given penetration level. This indicates that the specific locations of the wind and solar resources within WestConnect are not critical, provided there is adequate transmission infrastructure and access, and balancing area cooperation (see Sections 4.2.3, 5.5, 6.4.1, 6.4.6, 7.3.1). The assumption that existing transmission capacity can be fully utilized is an important change from present practice underpinning these results.

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Figure 15 shows the study footprint s monthly wind and solar energy as a percentage of load energy for all three scenarios in the 30% case in 2006.

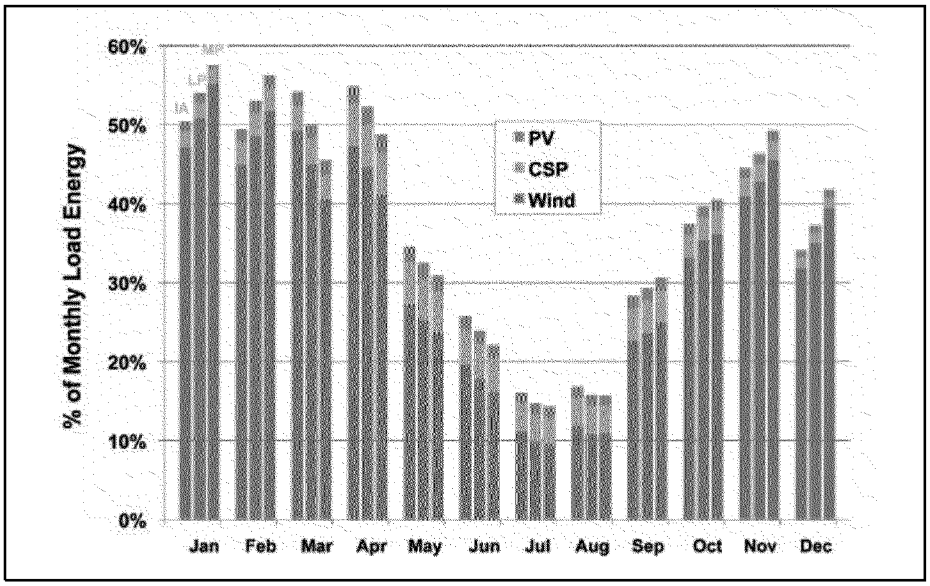


Figure 15 – The month-to-month variation of wind and solar penetration is greater than the scenario-to-scenario variation.

The plots clearly illustrate that 1) despite the month-to-month variation, there is relatively little difference among scenarios at the footprint resolution and 2) there is significant month–to-month variation in energy across the year. In fact, there is more interannual variation in each month s penetration levels than there is inter-scenario variation (see Section 4.1.1-4.1.2)

The total WECC operating cost savings per MWh of renewable energy for the different scenarios was also very similar across the three geographic scenarios, with only a slight increase in value as the wind plant locations were shifted to the higher capacity factor sites in the Local Priority and Mega Project Scenarios (see Section 6.4.1)

IS NEW LONG DISTANCE TRANSMISSION NEEDED?

Sufficient intra-area transmission within each state or transmission area for renewable energy generation to access load or bulk transmission is needed. However, the In-Area Scenario, which included no additional long distance, interstate transmission, worked just as well operationally as the other scenarios. A sensitivity case examined the impact of the interstate transmission build-outs in the Local Priority and Mega Project Scenarios (which required $3.4 and $11 billion dollars, in 2008$, of interstate transmission respectively). Figure 16 shows the increased annual operating

> **Up to 20% renewable penetration could be achieved with little or no new long distance, interstate transmission additions, assuming full utilization of existing transmission capacity.**

costs for the cases in which the new interstate transmission build-outs associated with the Local Priority and Mega Project Scenarios were eliminated. These increased costs are modest because renewables have displaced other generation and freed up transmission capacity. Assuming renewables have full access to this newly opened up capacity, there is less need for new transmission.

Assuming a 15% fixed charge rate, the 30% Local Priority Scenario would justify about $2 billion ($1.7 billion in 2009$) in transmission investments and the Mega Project Scenario would justify a little over $10 billion ($8.5 billion in 2009$). This rough estimate suggests that the full-scale transmission build-out might be justified in the 30% Mega Project Scenario, but not at lower penetrations in the Mega Project or for any of the other scenarios. A more limited transmission build-out may be justified for the Local Priority Scenario. Of course, these estimates do not include any reliability benefits that would be realized from adding more transmission. Ail scenarios could be built out to the 10% case without any new interstate transmission (see Section 6.4.6).

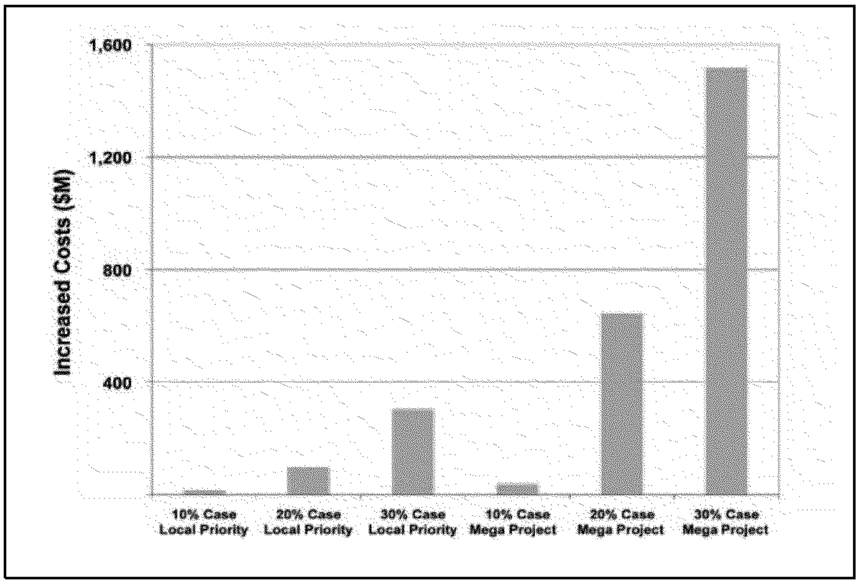


Figure 16 – Building the Local Priority and Mega Project Scenarios without the accompanying interstate transmission, increases costs at high penetrations in the Mega Project Scenario.

IS ADDITIONAL STORAGE NEEDED?

Storage can provide many benefits to the system, including price arbitrage (charging when spot prices are low and discharging when prices are high), reliability, and ancillary services. Pumped storage hydro (PSH), solar thermal storage, and plug-in hybrid electric vehicles (PHEVs) were examined in WWSIS, with the largest focus on PSH (see Chapter 8). WWSIS evaluated only the price arbitrage part of the value proposition for PSH and found it much less than sufficient to economically justify additional storage facilities.

In the 10% and 20% wind penetration scenarios, gas generation is always on the margin (meaning that there are only small spot price variations during most days). As a result, there is no apparent opportunity to economically justify energy storage based on price arbitrage. Spot price variations increase in the 30% wind penetration scenarios, primarily due to errors in day-ahead wind energy forecasts. Occasionally, the price swings are very large. However, because this is driven by forecast uncertainty, it is not possible to strategically schedule the use of storage resources to take advantage of the price variations (and subsequently help eliminate the operational problems due to wind forecast errors).

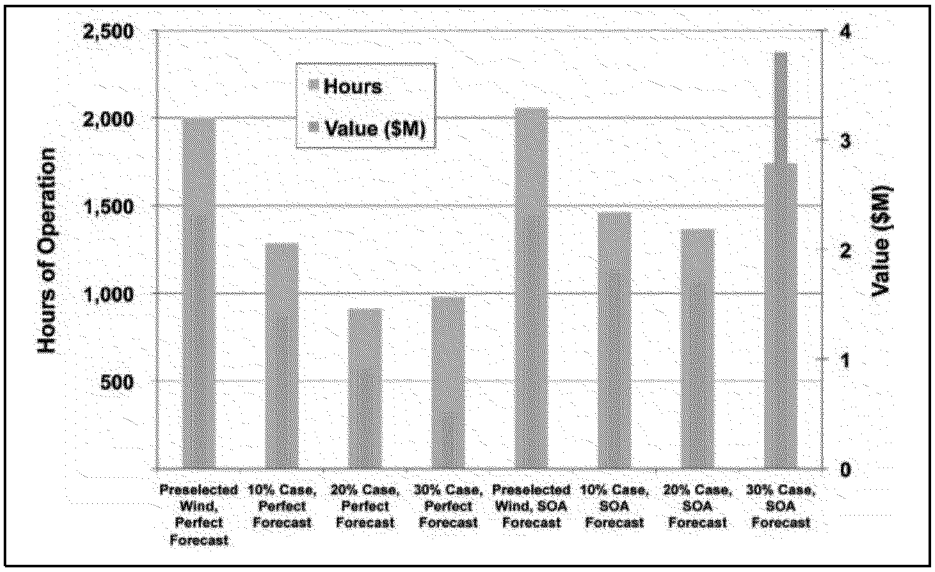


Figure 17 –A new 100-MW PSH plant with perfect pricing foresight would earn approximately $4 million/yr ($3.4million/yr in 2009$) from price arbitrage in the 30% case.

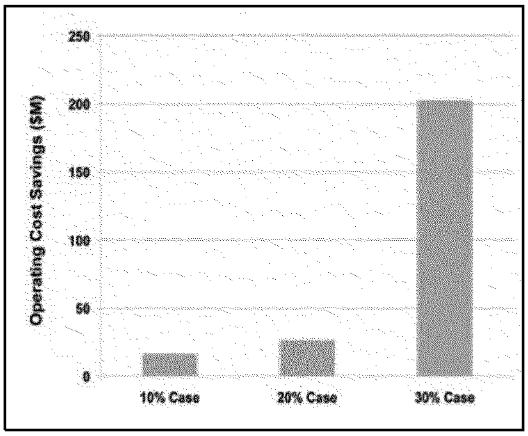
To examine a best-case scenario for storage, a new 100-MW PSH plant was added to the system and given perfect foresight of spot prices so that it could be dispatched to optimize revenue. The results in Figure 17 show the resulting number of operating hours and value. With no renewables, the PSH unit would run about 2200 hours (total pumping and generating time) and have an operating value of about $2.6 million ($2.2 million in 2009$) for the year. With a perfect forecast, the value of the PSH unit decreased as the renewable penetration increased, due to decreased spot prices. With 30% penetration and a perfect forecast the 100-MW PSH plant only had an annual operating value of $0.5 million ($0.4 million in 2009$) which would only yield a capitalized value of about $35/kW ($30/kW in 2009$). With an SOA forecast, spot prices are higher due to forecast error, and the 30% case increased the PSH annual operating value to $3.8 M ($3.2M in 2009$). However, this is several times less than would be required to recover costs for a new PSH plant (see Section 8).

WHAT IS THE BENEFIT OF FLEXIBILITY IN THE REST OF THE GENERATION FLEET?

System flexibility is the key to accommodating increased renewable generation. WWSIS finds that at higher (30% case) penetration levels, decreased flexibility of either the coal or hydro facilities made operation more difficult and increased the costs of integrating the renewable generation.

ALLOWING HYDRO TO PROVIDE LOAD FOLLOWING FOR WIND/SOLAR VARIABILITY IS HELPFUL

Hydro generation is capable of quick start/stop cycling and fast ramping, which makes it a good partner for variable wind and solar generation. Sensitivity analyses were conducted to examine the effects of hydro constraints on operating costs (see Section 6.4.2).



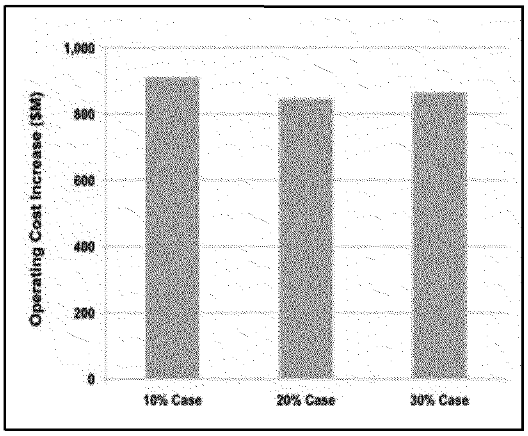


Figure 18 – Decreasing the flexibility of the hydro system increases costs. *Operating cost savings for hydro dispatch to net load (left), and operating cost increase for constant output hydro operation (right), WECC.*

This study assumed that hydro generation is normally committed and dispatched to serve daily peak net-load periods, while respecting the minimum operating points on the hydro units. The left side of Figure 18 shows the impact of adjusting the hydro schedules to account for the day-ahead renewable forecasts. Although the impact is relatively small at low levels of penetration, the WECC operating costs would be reduced by $200 million/yr ($170 million/yr in 2009$) at the 30% case, increasing the value of wind and solar energy by about $1/MWh ($0.9/MWh in 2009$).

The right side of Figure 18 examines the impact if hydro operation were severely constrained, such as a requirement to maintain constant river flow. In this case, the WECC operating costs would increase by up to $1 billion/yr ($0.9 billion/yr in 2009$). Clearly it is important to maintain as much operational flexibility as possible with the hydro generation (see Section 6.4.2).

[4] *Assuming $1200-2000/kW capital cost and a fixed charge rate of 15% for a new PSH, $18-30 million annually would be needed to recover capital costs.*

CONSTRAINTS ON COAL PLANTS RESULT IN HIGHER OPERATING COSTS

In WWSIS, coal plants were assumed to be able to operate down to minimum generation levels of 40% of nameplate capacity. WWSIS finds that higher minimum generation levels result in increased operating costs.

A sensitivity case explored the impact of varying coal plant minimum loading on system operating costs. Increasing the minimum loading had minimal impact with wind penetrations less than 20%. At the 30% scenario, the impact becomes more noticeable, as shown in Figure 19. If coal plants are allowed to only operate above 70% load, then WECC operating costs would increase by nearly $160 million/yr ($136 million/yr in 2009$). See Section 6.4.4.

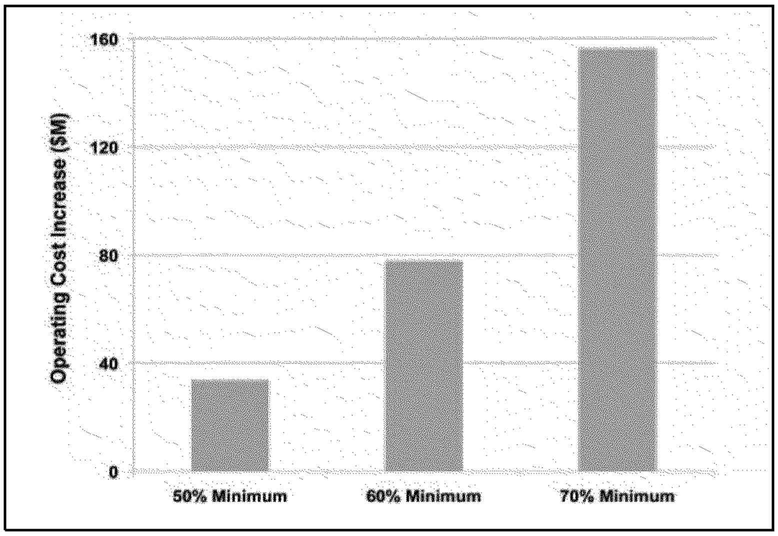


Figure 19 – Decreasing the flexibility of the coal fleet by increasing minimum generation levels on coal plants increases costs. *Increased WECC operating costs over 40% minimum ratings on coal plants, 30% case.*

WHAT IS THE CONTRIBUTION OF RENEWABLES TO RESOURCE ADEQUACY?

Variable resources such as wind and solar PV are primarily energy resources rather than capacity resources. However, they provide some contribution to reliability (resource adequacy). A range of capacity valuation techniques based on traditional loss-of-load-expectation (LOLE) data were evaluated to consider the variability inherent with the renewable generation. This was conducted for WestConnect assuming no transmission constraints within the study footprint and no interconnections with the rest of WECC, so that the capacity value characteristics of the renewable generation could be isolated.

Table 4 shows capacity values of wind based on daily LOLE which were typical of the overall analysis. Wind generation resources selected for this study were found to have capacity values in the range of 10% to 15%. Wind plant energy output tends to be higher during winter and spring seasons, and during nighttime hours, which is contrary to system peak load periods. Hence, the capacity value is low relative to the plant rating. PV solar plants have capacity values in the range of 25% to 30%. Although PV solar produces its energy during the daytime, output tends to decline in the late afternoon and early evening when peak load hours often occur. The PV output was based on the DC rating of the system; it would be 23% higher if based on the AC rating and included inverter and other losses from the outset. Concentrating solar plants with thermal energy storage have capacity values in the range of 90% to 95%, similar to thermal generating plants. Their maximum energy production tends to be during the long summer days, and the storage capability extends the energy output through the late afternoon and early evening hours, when peak loads occur (see Sections 4.2, 4.3, and 9.2 through 9.7).

Wind was found to have capacity values of 10-15%; PV was 25-30%; and CSP with 6 hours of thermal energy storage was 90-95%.

TABLE 4 – CAPACITY VALUES FOR 2004-2006.

CASE	WIND ONLY	PV ONLY	CSP ONLY	WIND+PV+CSP
10%	13.5%	35.0%	94.5%	18.2%
20%	12.8%	29.3%	94.8%	19.7%
30%	12.3%	27.7%	95.3%	19.8%

CONCLUSIONS AND NEXT STEPS

The technical analysis performed in this study shows that it is feasible for the WestConnect region to accommodate 30% wind and 5% solar energy penetration. This requires key changes to current practice, including substantial balancing area cooperation, sub-hourly scheduling, and access to underutilized transmission capacity.

WWSIS finds that both variability and uncertainty of wind and solar generation impacts grid operations. However, the uncertainty (due to imperfect forecasts) leads to a greater impact on operations and results in some contingency reserve shortfalls and some curtailment, both of which are relatively small. The variability leads to a greater sub-hourly variability reserve requirement, but because conventional units are backed down, the system naturally has extra reserve margins.

This study has established both the potential and the challenges of large scale integration of wind and solar generation in WestConnect and, more broadly, in WECC. However, changes of this magnitude warrant further investigation. The project team regards the following as valuable topics for exploration:

- Characterization of the capabilities of the non-renewable generation portfolio in greater detail (e.g., minimum turndown, ramp rates, cost of additional wear and tear);
- Changes in non-renewable generation portfolio (e.g., impact of retirements, characteristics, and value of possible fleet additions or upgrades);
- Reserve requirements and strategies (e.g., off-line reserves, reserves from non-generation resources);
- Load participation or demand response (e.g., functionality, market structures, PHEV);
- Fuel sensitivities (e.g., price, carbon taxes, gas contracts and storage, hydro constraints and strategies);
- Forecasting (e.g., calibration of forecasting using field experience, strategies for use of short-term forecasting);
- Rolling unit commitment (e.g., scheduling units more frequently than once on a day-ahead basis);
- Transmission planning and reliability analyses (e.g., transient stability, voltage stability, protection and control, intra-area constraints and challenges);
- Hydro flexibility (e.g., calibration of hydro models with plant performance).

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ENERNOC OPENING TESTIMONY OF MONA TIERNEY-LLOYD
JUNE 25, 2012

Footnotes 19 - 21, at Page III-3

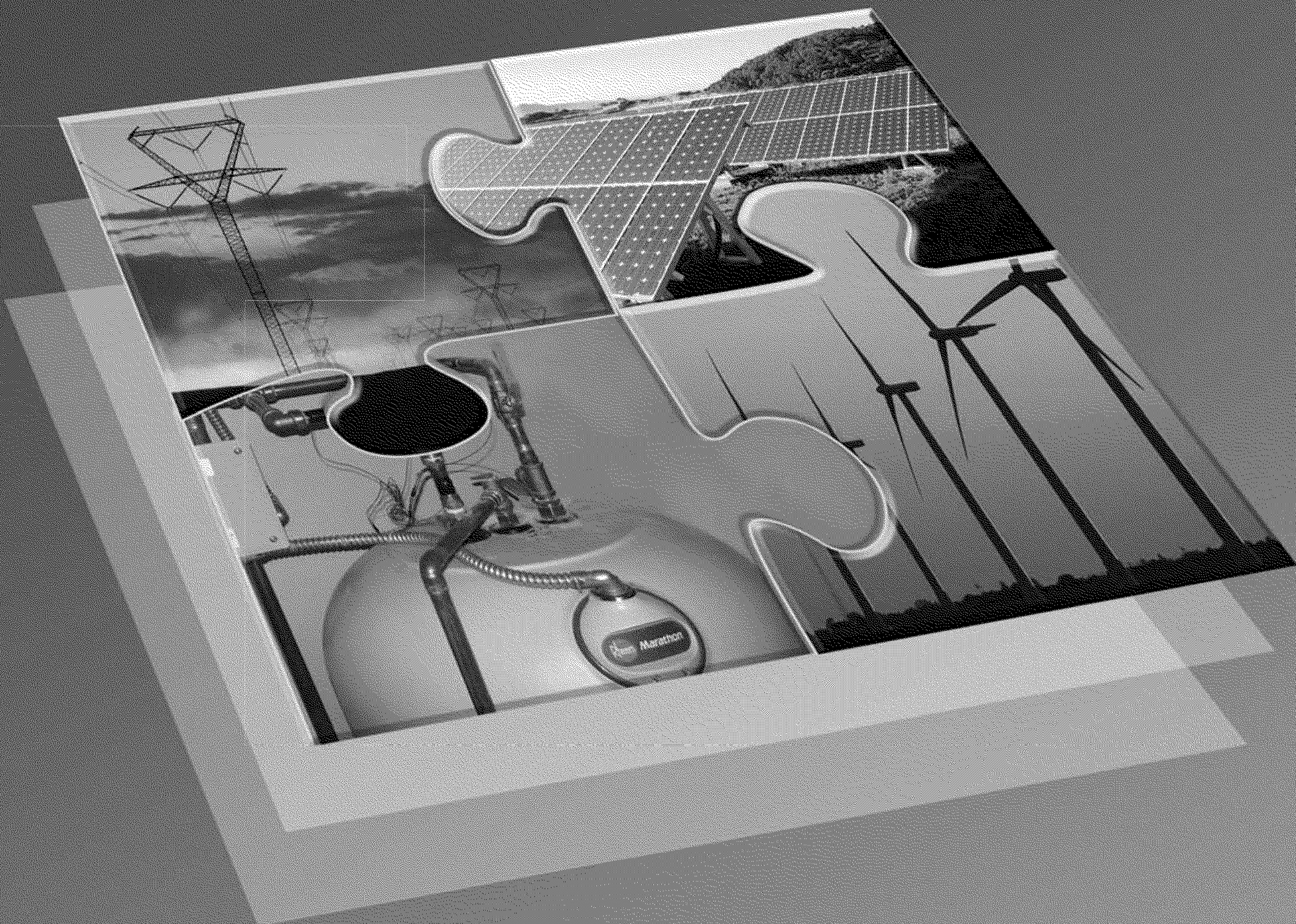
Western Governor's Association (WGA)

Meeting Renewable Energy Targets in the West at Least Cost: The Integration Challenge
Executive Summary

June 10, 2012

Meeting Renewable Energy Targets in the West at Least Cost: The Integration Challenge

Executive Summary



June 10, 2012
Western Governors' Association

The Integration Challenge

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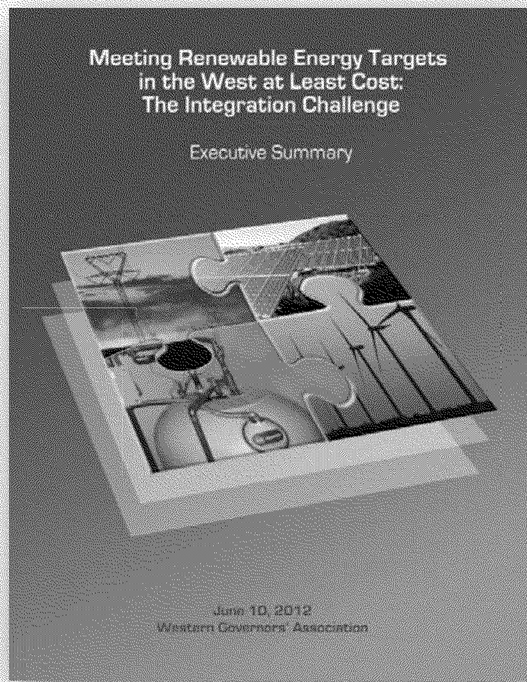
Western Governors' Association

Meeting Renewable Energy Targets in the West at Least Cost: The Integration Challenge

Introduction

Clean, affordable energy is essential for continued growth of the economy in Western states. State laws and policies put in place in the last decade requiring energy suppliers to bring on-line large amounts of wind and solar generation have changed the traditional mix of "fuels" used for energy generation. By 2022, these policies are expected to more than double the amount of renewable resources in the Western U.S. compared to 2010.



Integrating these resources into a reliable and affordable power system will require an unprecedented level of cooperative action within the electric industry and between the industry and state, subregional and federal entities. Western Governors have encouraged utilities and transmission providers to reduce the cost of integrating renewable energy (see WGA Resolution 10-15). These efforts need to increase as wind and solar resources scale up to help power the Western economy in the future.

Western Governors can help accelerate these efforts by:

* Asking for regular reports from utilities and transmission providers serving their state on actions they are taking to put in place recommendations in this paper;
* Calling for an assessment from the state's utility regulators and energy office on whether an energy imbalance market and faster scheduling of energy and transmission could reduce ratepayer costs and, if so, what is needed to put these practices in place;
* Urging transmission providers and federal power marketing agencies to evaluate the cost and benefits of actions to increase transmission capacity and system flexibility and act on ones that look most promising;
* Directing state agencies to incorporate the recommendations in this report in state energy and transmission plans and economic development initiatives and requesting utilities and regulators to include the recommendations in requirements for utility resource plans and procurement;
* Asking utilities and state agencies to work collaboratively to inventory generating facilities and evaluate future flexibility options to integrate wind and solar resources; and
* Convening parties to discuss benefits to the region from least-cost delivery of wind and solar resources and to develop solutions to address institutional barriers.

The Western Governors' Association commissioned this report to explore ways to reduce costs to the region's electricity consumers for integrating wind and solar, identify barriers to adopting these measures and recommend possible state actions.

The Western U.S. power grid has existing flexibility in the system to cost-effectively integrate wind and solar resources but, as operated today, that flexibility is largely unused. Integration involves managing the variability (the range of expected electricity generation output) and uncertainty (when and how much that generation will change during the day) of energy resources.

Integration is not an issue that is unique to renewable resources; conventional forms of generation also impose integration costs. In fact, most of the measures described in the report would reduce costs and improve the reliability of the grid even if no wind or solar generation is added.

Other regions of the country have found ways to increase flexibility and efficiency from supply- and demand-side resources and transmission, although the West faces some unique challenges including:

* The Western Interconnection is a large area that includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of 14 Western states.
* It is organized into 37 balancing authorities that operate independent areas within an interconnected grid system.
* Energy and capacity are acquired primarily through utility-built projects and long-term bilateral agreements driven by utility resource plans and procurement processes.
* Outside of organized wholesale markets in Alberta and the California Independent System Operator (CAISO) footprint, subhourly energy transactions are limited.
* Energy is largely delivered on hourly schedules that are fixed shortly before the hour of delivery, with little (or no) ability to make changes.

Drawing from existing studies and experience to date, this report identifies operational and market tools as well as flexible demand- and supply-side resources that can be employed to reduce ratepayer costs for integrating wind and solar in the Western states. The following table provides a high-level overview of the costs and integration benefits for each of these approaches and indicates the level of certainty of these appraisals. The table also provides estimated timeframes for implementation. The remainder of the Executive Summary outlines these approaches and recommendations for states to consider.

Executive Summary

Assessment of Integration Actions

The following table takes a West-wide view of costs and integration benefits of actions described in this report and estimates implementation timeframe. Appendix A describes underlying assumptions. The extent to which any of these actions is undertaken, and therefore its costs and benefits, depend in part on the level of adoption of other actions. However, each action is treated independently here; there is no ranking of options against each other. Colors indicate confidence in the assessment of costs and integration of benefits: blue – high confidence, yellow – medium confidence, and orange – low confidence.

Option	Expected Cost of Implementation[1] (west-wide except where noted)	Expected Benefit for Integrating Variable Generation	Projected Timeframe in Implementing Option
Subhourly Dispatch and Intra-Hour Scheduling (non-standard, voluntary – not West-wide, 30-minute interval)	Low	Low	Short
Subhourly Dispatch and Intra-Hour Scheduling (standard, voluntary – not West-wide[2])	Low to Medium	Low to Medium	Short
Subhourly Dispatch and Intra-Hour Scheduling (standard, required, West-wide)	Low to High	Medium to High	Medium
Dynamic Transfers (improved tools and operating procedures)	Low	Low to Medium	Short to Medium
Dynamic Transfers (equipment upgrades, including new transmission lines)	Medium to High	Medium to High	Medium to Long
Energy Imbalance Market (subregion only)	Medium to High	Medium	Medium
Energy Imbalance Market (West-wide)	Medium to High	High	Medium to Long
Improve Weather, Wind & Solar Forecasting	Medium	Medium to High	Short to Medium
Geographic Diversity (if using existing transmission)	Low to Medium	Low to Medium	Medium
Geographic Diversity (if new transmission needed)	High	Medium	Long
Reserves Management: Reserves Sharing	Low	Low to Medium	Short
Reserves Management: Dynamic Calculation	Low	Low to Medium	Short
Reserves Management: Using Contingency Reserves for Wind Events	Low to Medium	Low to Medium	Short to Medium
Reserves Management: Controlling Variable Generation (assuming requirements are prospective)	Low to Medium	Low to Medium	Medium to Long
Demand Response: Discretionary Demand	Low to Medium	Low to Medium	Short to Medium
Demand Response: Interruptible Demand	Low to Medium	Low to Medium	Short to Medium
Demand Response: Distributed Energy Storage Appliances	Low to Medium	Low to Medium	Short to Medium
Flexibility of Existing Plants—Minor Retrofits	Low to Medium	Low to Medium	Short to Medium
Flexibility of Existing Plants—Major Retrofits	Medium to High	Medium to High	Medium to Long
Flexibility for New Generating Plants	Low to High	Medium to High	Medium to Long

[1] Low - less than $10 million region-wide; medium - between $10 million and $100 million; high – more than $100 million.

[2] Ranges in costs and integration benefits reflect differences in scheduling intervals– 5 to 15 minutes vs. 30 minutes.

Summary of Integration Actions

Expand subhourly dispatch and intra-hour scheduling.

Economic dispatch is the process of maximizing the output of the least-cost generating units in response to changing loads. Scheduling is the advance scheduling of energy on the transmission grid.

Subhourly dispatch refers to changing generator outputs at intervals less than an hour. Intra-hour scheduling refers to changing transmission schedules at intervals less than an hour. In organized energy markets in the U.S., regional system operators dispatch generation at five minute intervals and coordinate transmission with dispatch.

While most transmission in the Western Interconnection is scheduled in hourly intervals, output from variable energy resources changes within the hour. Greater use of subhourly dispatch and intra-hour scheduling in the West's bilateral markets could allow generators to schedule their output over shorter intervals and closer to the scheduling period, effectively accessing existing generator flexibility that is not available to most of the West today. Among other benefits, this would facilitate a large reduction in the amount of regulation reserves needed with significant savings for consumers.

Barriers to achieving these savings in the West include the upfront cost to move from hourly to intra-hourly scheduling; inconsistent practices across areas where intra-hour scheduling is allowed today; the need to synchronize metering, control center operations and software; lack of coordination of intra-hour scheduling with financial settlements; and the lack of a formal, standard market for intra-hour energy transactions outside Alberta and the CAISO footprint.

Recommendations for states to consider:

* Encourage expansion of the Joint Initiative's intra-hour scheduling activities to shorter time intervals.
* Promote expansion of subhourly dispatch and intra-hour scheduling to all entities in the West.
* Foster standardization of intra-hour scheduling among Western balancing authorities, allowing updating of schedules within the hour.
* Evaluate the costs, benefits and impacts of extended pilots on the need for reserves, particularly for regulation.
* Commission an independent analysis of the estimated equipment and labor costs of transitioning to subhourly dispatch and intra-hour scheduling for all transmission providers in the West. Such an analysis also should estimate the benefits, including projected reductions in regulation and other reserve needs, especially for balancing authorities with large amounts of variable energy resources. In addition, the study should evaluate costs and benefits of intra-hour scheduling operations, such as:
  1. two 30-minute schedules both submitted at the top of the hour,
  2. one 30-minute schedule submitted at the top of the hour and another at the bottom of the hour,
  3. 15-minute scheduling and
  4. five-minute scheduling.
* Consider strategies for assisting smaller transmission providers to recover costs of transitioning to intra-hour scheduling, such as coordinated operations among multiple transmission providers or phasing in equipment and personnel upgrades over multiple years.
* Explore harmonized implementation of faster dispatch, scheduling, balancing and settlement across the Western Interconnection.
* Allow regulated utilities to recover costs for wind integration charges assessed by a third party at the lesser of the rate charged for intra-hour scheduling or hourly scheduling, if intra-hour scheduling is an available option. Grant cost recovery for software upgrades and additional staff necessary to accommodate intra-hour scheduling.

Facilitate dynamic transfers between balancing authorities

Dynamic transfer refers to electronically transferring generation from the balancing authority area in which it physically resides to another balancing authority area in real-time. Such transfers allow generation to be located and controlled in a geographic location that is outside of the receiving balancing authority area. Dynamic transfer involves software, communications and agreements and requires the appropriate amount of firm, available transmission capacity between locations.

Dynamic transfers facilitate energy exchanges between balancing authority areas and increase operational efficiency and flexibility. Using dynamic transfers, the within-hour variability and uncertainty of a wind or solar facility can be managed by the balancing authority where the energy is being used. Absent dynamic transfers, that responsibility remains with the balancing authority area where the facility interconnects, even if the plant schedules the power to be sold in another region. Dynamic transfers can result in greater geographic diversity of wind and solar facilities and reduced integration costs and imbalance charges.

For most transmission providers in the Western Interconnection, transmission slated for dynamic transfers must be held open for the maximum dynamic flow that could occur within the scheduling period, typically an hour. Thus, transmission slated for dynamic transfers could displace other potential fixed, hourly transactions on the line. While reservations can be updated in real-time to be used by other market participants, increased dynamic transfers may come at the expense of other uses of the line.

Dynamic transfers also increase intra-hour power and voltage fluctuations on the transmission system that can pose challenges for system operators. The impacts are more difficult to manage as more dynamic transfers have large and frequent ramps within the scheduling period. Lack of automation of some reliability functions is a barrier to increased use of dynamic transfers, as are concerns about the impact on transmission system operating limits.

Recommendations for states to consider:

- Complete transmission provider calculations of dynamic transfer limits to help identify which lines are most receptive, and which are most restrictive for dynamic transfers.
- Determine priority for transmission system improvements to alleviate restrictions on dynamic transfers considering locations for existing and potential renewable generation and balancing resources, and lines needed for dynamic transfers.
- Assess options and costs for additional transmission capacity and additional flexibility on transmission systems to facilitate more widespread use of dynamic transfers. For example, more flexible AC transmission systems can be "tuned" to operate more flexibly. Dynamic line ratings can increase utilization of existing transmission facilities. Also, the impact of lower transmission utilization factors due to dynamic transfers could be minimized through upgrades such as reactive power support and special protection systems.
- Explore use of ramping limits to increase the dynamic transfer capability of certain paths.
- Assess best approaches for integrating dynamic transfer limits into scheduling and operating practices and determine compensation issues.

* Conduct outreach and disseminate information to stakeholders on the implications of dynamic transfer limits and potential system impacts of dynamic scheduling in order to help identify solutions. Dynamic transfer limits may have implications for other mechanisms that can help integrate renewable resources, such as an energy imbalance market and flexible reserves.
* Automate reliability procedures such as voltage control and RAS arming to enable expanded use of dynamic transfers and increase the efficiency of system operations.
* Use near real-time data to calculate system operating limits to address concerns about potential violations of limits due to lack of current data. This could help mitigate restrictive dynamic transfer limits.
* Encourage balancing authorities to use dynamic transfers to aggregate balancing service across their footprints.

Implement an energy imbalance market (EIM)

As proposed for the Western U.S., an EIM is a centralized market mechanism to:

1. re-dispatch generation every five minutes to maintain load and resource balance, addressing generator schedule deviations and load forecast errors and
2. provide congestion management service by re-dispatching generation to relieve grid constraints.

An EIM would increase the efficiency and flexibility of system operations to integrate higher levels of wind and solar resources by enabling dispatch of generation and transmission resources across balancing authorities. That would harness the full diversity of load and generation in a broad geographic area to resolve energy imbalances. An EIM would optimize the dispatch of imbalance energy within transmission constraints, reducing operating costs and reserve needs and making more efficient use of the transmission system. In addition, an EIM would provide reliability benefits by coordinating balancing across the region, making more generation available to system operators.

Among the implementation barriers are upfront financing and accepting and adapting to a new operational practice. Other issues to be resolved include selection of a market operator, governance, a market monitor to prevent and mitigate potential market manipulation, coordination agreements with reserve sharing groups, seams agreements with non-participants and organized market areas, and uncertainty in the level of interest in participation.

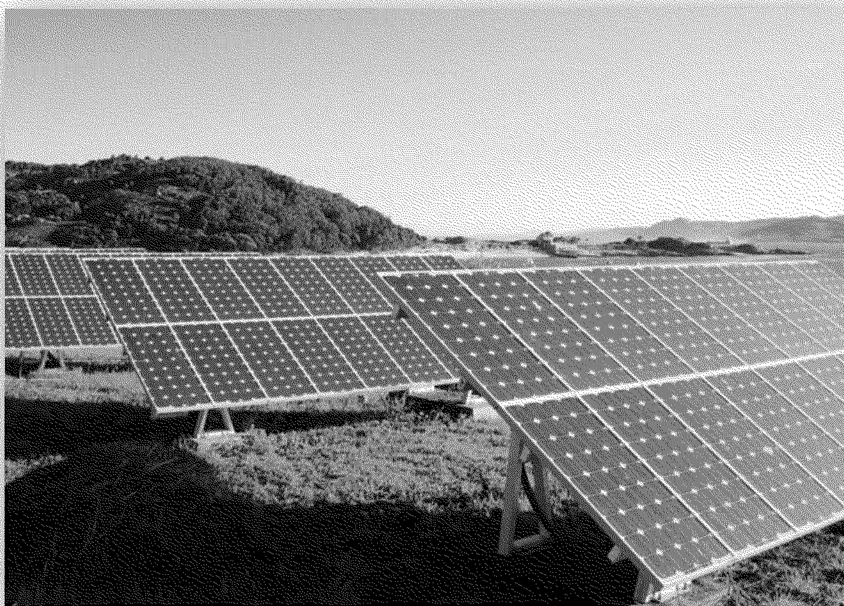
Recommendations for states to consider:

* Undertake efforts to define the rates and terms for transmission service agreements for each transmission provider.
* Explore financing options to enable entities to defer some of the startup costs to future years and to better plan and budget for costs.
* Investigate the costs and benefits to ratepayers of regulated utilities participating in an EIM through public utility commission proceedings. Encourage publicly owned utilities to investigate costs and benefits of EIM participation for their consumers. Such evaluations should include potential reduction in integration costs, potential enhanced reliability, changes to compensation for transmission providers and impacts for customers, potential disadvantages of participation, and possible negative economic impacts for meeting renewable energy requirements in the absence of utility participation in an EIM.
* Examine mechanisms for preventing and mitigating potential market manipulation that could reduce benefits.
* Support continuing efforts to explore how governance of an EIM would work, including provisions that address concerns that an EIM could lead to the creation of an RTO.
* Determine the viability of an EIM if major balancing authorities do not participate.
* Provide encouragement and support for the Northwest Power Pool Market Assessment and Coordination Committee which has assembled 20 Western balancing authorities and several other participating utilities to fully evaluate the business case for an EIM.

- Support Western Interconnection-wide efforts to design a proposed EIM for the broadest possible geographic footprint.
- Establish a timeline for implementing the proposed EIM in the West.

Improve weather, wind and solar forecasting

Weather is a primary influence on all electric systems as it drives load demand, in addition to variable generation sources such as wind and solar. Hot days require more power generation to meet demand for cooling, while cold weather requires more generation to serve electric heating requirements. Thus, forecasting of variable generation should be viewed in the broader context of weather forecasting.



Variable generation forecasting uses weather observations, meteorological data, Numerical Weather Prediction models, and statistical analysis to generate estimates of wind and solar output to reduce system reserve needs. Such forecasting also helps grid operators monitor system conditions, schedule or de-commit fuel supplies and power plants in anticipation of changes in wind and solar generation, and prepare for extreme high and low levels of wind and solar output.

Key barriers to greater use of wind and solar forecasting are deficiencies in forecast accuracy, time required to implement forecasting processes including collection of necessary data, increased need to incorporate variable generation forecasts in day-ahead schedules and dispatch, and lack of updating schedules and dispatch with more accurate forecasts closer to real time. In addition, improvements in the foundational forecasts that variable generation forecasters rely upon will improve the quality and accuracy of variable generation forecasts. Improvements including more frequent measurements and observations, more measurements from the atmosphere, and more rapid refreshing of Numerical Weather Prediction models will improve variable generation forecasting as well as weather forecasting, which have broader benefits for the public, the aviation industry and other users of weather data.

Recommendations for states to consider:

- Support government and private industry efforts to improve the foundational models and data that are incorporated into variable generation forecasting models.
- Encourage the expanded use of variable generation forecasting by balancing authorities.
- Ask balancing authorities that already have implemented variable generation forecasting to study the feasibility and costs and benefits of improvements, such as using multiple forecasting providers or installing additional meteorological towers.
- Study the feasibility and costs and benefits of using variable generation forecasts for day-ahead unit commitments and schedules, including updating schedules closer to real time to take advantage of improved forecast accuracy.

* Consider the feasibility and costs and benefits of more regional variable generation forecasts involving multiple balancing authorities or exchange of forecasts among balancing authorities.
* Ask balancing authorities whether variable generation ramps are of concern now or are expected to be of concern in the future, whether any existing forecasting system adequately predicts ramps in variable generation, and the status of potential adoption of a ramp forecast for variable generation.

Take advantage of geographic diversity of resources

Over a large geographic area, and a corresponding large number of generating facilities, wind and solar projects are less correlated and have less variable output in aggregate. This reduces ramping of conventional generation for balancing, as well as forecasting errors and the need for balancing (not contingency) reserves.

Some regions in the U.S. have large balancing authority areas that naturally provide geographic diversity. Diversity also can be accessed through greater balancing authority cooperation, building transmission and optimized siting of wind and solar plants.

Siting these resources without regard to geographic diversity may have higher costs compared to projects sited to minimize transmission costs. However, if the resource sites are not of equal quality, more wind and solar capacity may be required to achieve the same generation output – at higher cost – compared to developing higher quality resources that are geographically concentrated.

Although the benefits of geographic diversity are generally recognized, there is insufficient information that quantifies the costs and benefits. Further, geographic diversity is typically not factored into transmission planning or resource planning and procurement processes. The question is whether reducing aggregate variability of variable generation through geographic diversity, with the resulting reductions in reserves requirements and wind and solar forecast errors, justifies initiatives such as transmission expansion. By itself, geographic diversity is probably insufficient to justify new or upgraded transmission lines but it may be an additional benefit. Regardless, the benefits of geographic diversity clearly support balancing authority area aggregation and greater cooperation across areas.

Recommendations for states to consider:

* Quantify the costs and benefits of geographic diversity in utility resource plans and procurement, subregional plans and Interconnection-wide plans. This includes, but is not limited to, siting wind and solar generation to minimize variability of aggregate output and better coincide with utility load profiles.
* Investigate the pros and cons of siting optimization software and whether it can be advantageously used in processes such as defining state and regional renewable energy zones and utility resource planning and procurement to reduce ramping of fossil-fuel generators and minimize reserve requirements.

- Support right-sizing of interstate lines that access renewable resources from regional renewable energy zones designated through a stakeholder-driven process in areas with low environmental conflicts, when it is projected that project benefits will exceed costs. Right-sizing lines means increasing project size, voltage, or both to account for credible future resource needs. Building some level of transmission in advance of need could avoid construction of a second line in the same corridor or minimize the need for additional transmission corridors, and associated environmental disruption, as well as the risk that transmission may not be available to deliver best resources identified in long-term planning.

Improve reserves management

Power system reserves are quantities of generation or demand that are available as needed to maintain electric service reliability. Contingency reserves are for unforeseen events, such as an unscheduled power plant outage. Balancing reserves are for day-to-day balancing of generation and demand.

Higher penetrations of wind and solar resources increase the variability and uncertainty of generation in the system, increasing the need for balancing reserves. These reserves can be managed more efficiently. First, reserve sharing can reduce the requirements of individual balancing authorities by averaging out short-term load and resource fluctuations across a broader area. Second, dynamically calculating regulation and load following reserves would take into account levels of renewable generation (for example, variability of wind plant output changes with output level), load on the system and other system conditions. Third, system operators can work with reliability entities to determine whether contingency reserves could be used for extreme events when wind output drops rapidly. Fourth, relatively modest limits and ramp rate controls for variable generation could significantly reduce the need to hold balancing reserves, at the cost of curtailing some output of renewable energy generation. Automatic generation control for down-regulation also may prove useful if variable generators are compensated for the service.

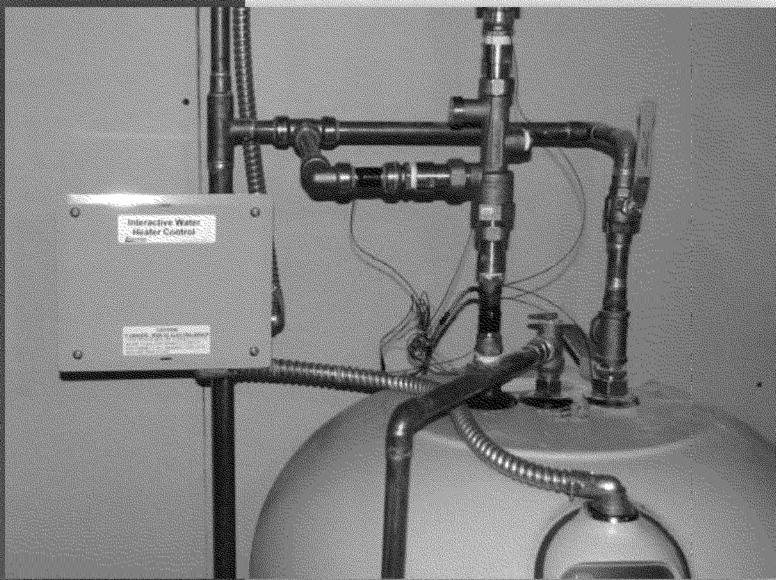
The first two of these approaches are more proven, while at least some aspects of the latter two approaches are less developed. Among the implementation barriers, additional research and implementation experience are needed in several areas.

Recommendations for states to consider:

- Equip more existing conventional generating facilities with automatic generation control. Experiment with automatic generation control for wind projects and evaluate the benefits to the system against compensating wind generators for lost output.
- Expand reserve-sharing activities such as ADI. Implementation costs are minimal and benefits may be substantial. In addition, ADI programs should consider expanding capacity limits.
- Request the WECC Variable Generation Subcommittee to analyze dynamic reserve methods to help with wind and solar integration.
- Ask balancing authorities to explore calculating reserve requirements on a dynamic basis to take into account the levels of wind and solar on the system and other system conditions.
- Perform statistical analysis to determine the benefits in reduced net reserves that result if balancing reserves for wind and contingency reserves can be at least partially shared. If results are positive, work with NERC and WECC to develop protocols allowing the use of contingency reserves for extreme wind ramping events.
- Develop coordinated or standardized rules for controlling variable generation that minimize economic impacts to wind and solar generators. Controls should be limited to situations where actions are needed to maintain system reliability or when accepting the variable generation leads to excessive costs.
- Consider different wholesale rate designs to encourage more sources of flexibility.

Retool demand response to complement variable supply

Where the fuel that drives a growing share of supply is beyond the control of system operators, as is the case with wind and solar energy, it is valuable to shift load up and down by controlling water heaters, chillers and other energy services. To realize significant integration benefits this must be done through either direct control of the load or pre-programmed responses to real-time prices.



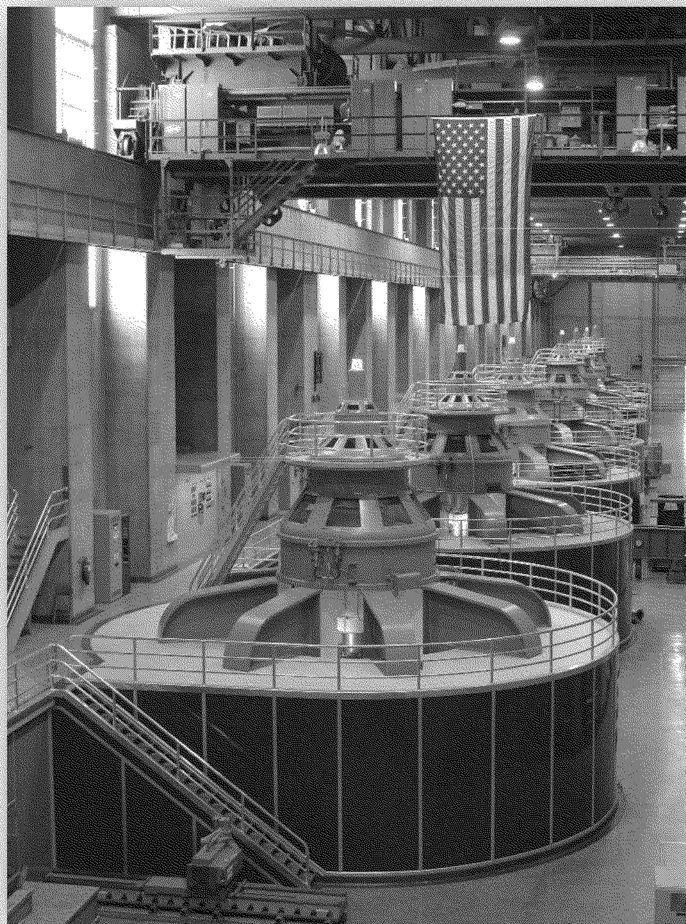
Experience in some regions and results from studies suggest that demand response can be a key component of a low-cost system solution for integrating variable generation. Demand response also provides many other benefits, including increased customer control over bills, more efficient delivery of energy services and a more resilient power system.

Among the barriers, demand response programs that could help integrate variable generation are nascent, advanced metering infrastructure is not in place in many areas, better customer value propositions are needed, and strategies for measuring and verifying demand response must be improved.

Recommendations for states to consider:

* Consider demand response as part of a suite of measures designed and deployed to complement the reliable and cost-effective deployment of larger shares of variable energy resources.
* Further develop and test a range of value propositions to assess customer interest in direct load control and pricing event strategies that support variable generation, with frequent control of loads both up and down.
* Evaluate experience with program designs that pay consumers based on the value of the flexibility services they provide to system operators, with either direct control of selected loads or automated load responses programmed for customers according to their preferences.
* Consider the potential value of enabling demand response programs that can help integrate variable generation when evaluating utility proposals for advanced metering infrastructure.
* Particularly for real-time pricing based programs, cultivate strategies that earn consumer confidence in advanced metering infrastructure and pricing programs, including development of robust policies safeguarding consumer privacy and well-designed consumer education programs.
* Allow and encourage participation of third-party demand response aggregators to accelerate the development of new sources of responsive demand, new consumer value propositions and new service offerings. Address open-source access to demand response infrastructure, access to consumer information, and privacy and data security issues to enable third parties to offer demand response products and services.
* Allow demand response to compete on an equal footing with supply-side alternatives to provide the various services it is capable of delivering. Further, actively accommodate demand response in utility solicitations for capacity.
* Isolate and quantify costs of balancing services to make transparent the value of flexibility options such as demand response.
* Develop robust measurement and verification processes that recognize the unique characteristics of demand-side resources in ways that encourage, rather than discourage, wider participation.
* Examine ratemaking practices for features that discourage cost-effective demand response. Examples include demand charges that penalize (large) customers for higher peak demand levels when they shift load away from periods of limited energy supplies to periods of surplus, and revenue models that tie the utility's profits primarily to volume of energy sales.

Access greater flexibility in the dispatch of existing generating plants



Output control range, ramp rate and accuracy – along with minimum run times, off times and startup times – are the primary characteristics of generating plants that determine how nimbly they can be dispatched by the system operator to complement wind and solar resources. There are economic tradeoffs between plant efficiency, emissions, opportunity costs (the revenue lost when a generator foregoes energy production in order to provide flexibility), capital costs and maintenance expenses.

The best way to achieve the needed generator flexibility is to design and build it into the fleet, selecting technologies that are inherently flexible. Some plants can be retrofitted to increase flexibility by lowering minimum loads, reducing cycling costs and increasing ramp rates. Generators that can reduce output or shut down when wholesale market prices are lower than their operating costs can make more money than generators that have to continue operating at a loss.

Among the barriers to retrofitting plants are the fundamental limitations of the technology, uniqueness of each plant, cost and uncertain payback. The benefits of increasing existing plant flexibility may be comparatively small compared to other ways to reduce integration costs, such as larger balancing authorities and intra-hour scheduling. But the benefits are additive.

Recommendations for states to consider:

First, establish generator scheduling rules that do not block access to the flexibility capability that already exists. Subhourly energy scheduling has proven to be an effective method for maximizing the flexibility of the generation fleet. Second, perform balancing over as large a geographic area as possible. The larger the balancing area, the greater diversity benefit where random up and down movements of loads and variable generators cancel out. Third, design flexibility into each new generator by selecting technologies that are more flexible.

Fourth, retrofit existing generators to increase flexibility when this is practical and cost-effective:

* Analyze the potential for retrofitting existing, less flexible generating facilities. Evaluation on a plant-specific basis is required to determine what additional flexibility, if any, can be obtained through cost-effective modification. It may be possible to achieve faster start-ups, reduce minimum loads, increase ramp rates (up and down), or increase the ability to cycle the generator on and off, or off overnight, and at other times when it is not needed.
* Provide appropriate incentives to encourage generating plant owners to invest in increased flexibility.
* Consider establishing incentives or market options to encourage generators to make their operational flexibility available to system operators.

- Explore development of a flexible ramping ancillary service to take advantage of fast-response capabilities of some types of demand resources and generation.
- Require conventional generators to have frequency response capability or define frequency response as a service that generators can supply for compensation.
- Quantify cycling costs and identify strategies to minimize or avoid cycling.

Focus on flexibility for new generating plants

Traditionally, system operators relied on controlling output of power plants – dispatching them up and down – to follow highly predictable changes in electric loads. Generating plants were scheduled far in advance with only small adjustments in output required to follow changes in demand.

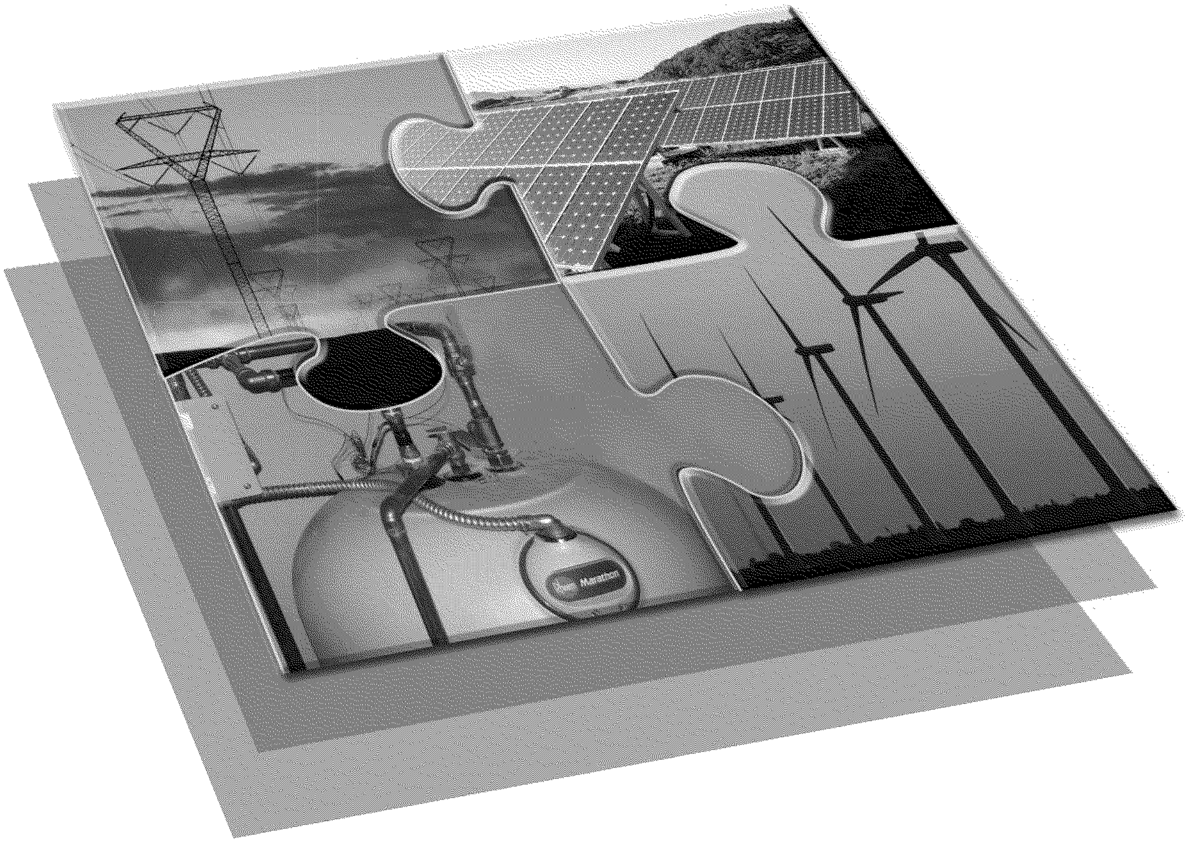
With an increasing share of supply from variable renewable energy resources, grid operators will no longer be able to control a significant portion of generation capacity. At the same time, renewable resources are among the most capital-intensive and lowest cost to operate. Once built, typically the least-cost approach is to run them as much as possible. Therefore, grid operators will need dispatchable generation with more flexible capabilities for following the less predictable "net load" – electricity load after accounting for energy from variable generation.

New dispatchable generation will need to frequently start and stop, change production to quickly ramp output up or down, and operate above and below standard utilization rates without significant loss in operating efficiency. Flexible resources that can meet increased system variability needs with high levels of wind and solar generation will enable more efficient system operation, increased utilization of zero variable-cost resources, and lower overall system operating costs.

A significant challenge is assessing how much flexible capacity already exists and how much will be needed – and when. Resource planning and procurement processes typically are not focused on flexible capability. New metrics and methods are needed to assess flexibility of resource portfolios and resource capabilities needed in the future.

Recommendations for states to consider:

- Retool the traditional approach to resource adequacy and planning analysis to reflect the economic benefit of flexibility service.
- Conduct a flexibility inventory of existing supply- and demand-side resources.
- Evaluate the need for flexible capacity at the utility, balancing authority, subregional and regional levels.
- Examine how utility resource planning and procurement practices evaluate long-term needs, benefits and costs of flexible capacity with increasing levels of variable renewable energy resources, including capabilities and limitations of analytical tools and metrics. Amend planning requirements or guidance to address these needs.
- Review recommendations of NERC's Integration of Variable Generation Task Force on potential metrics and analytical methods for assessing flexibility from conventional power plants for application in utility resource planning and procurement.
- Examine incentives and disincentives for utilities to invest in flexible supply- and demand-side resources, including those directed at resource adequacy, to meet the growing demand for flexibility services.
- Use competitive procurement processes to evaluate alternative capacity solutions, looking beyond minimum requirements for resource adequacy and analysis focused simply on cost per unit. Specify capabilities, not technologies and fuels, allowing the market to bring the most attractive options.
- Review air pollutant emissions rates allowed under state rules for impacts on procurement of flexible generation, with the aim of maintaining integrity of overall environmental goals.



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