WESTERN INTERSTATE ENERGY BOARD

Integration of Renewable Variable Energy Resources

Thomas A. Carr

2/28/2017

Acknowledgment: The information, data, or work presented herein was funded in part by the Office of Energy Efficiency and Renewable Energy (EERE), U.S. Department of Energy, under Award Number DE-EE0006884.

Table of Contents

1. Introduction

Emerging technology and policy drivers are causing significant changes in the generation resource mix of the power sector. Renewable energy is becoming an increasing and significant source of electric generation. The largest share of renewable energy growth comes from wind and solar technologies, both of which are known as variable energy resources (VERs) that have variable dispatch patterns dependent on weather conditions and sunlight. An important emerging issue is the impact of increasing levels of renewable variable energy resources on the operations and reliability of the power system.

The ability of the power system to integrate variable energy resources depends on a number of interrelated factors and conditions. Research over the past six years is providing new and interesting insights on this question. One of the most important challenges facing policy makers and regulators in the Western Interconnection is finding technological and economically efficient solutions to integrating higher levels of variable energy resources into the power system.

Since the early 2000s, many Western states enacted renewable portfolio standards (RPS) to promote the development of renewable energy. There are a mix of different and unique RPS policies for all states and provinces in the Western Interconnection. California and Oregon have recently increased their top RPS rate to 50%. Future carbon reduction policies could lead to even greater use of renewable energy across states and provinces in the Western Interconnection.

This paper examines the issues associated with integrating variable generation in the power system over the 10-20 year planning horizon. The paper draws upon the research of recent studies that have modeled the Western Interconnection under high levels of renewable energy and explored steps to facilitate more efficient operations. These findings provide the basis for a series of options that policymakers and regulators may consider for the electric sector.

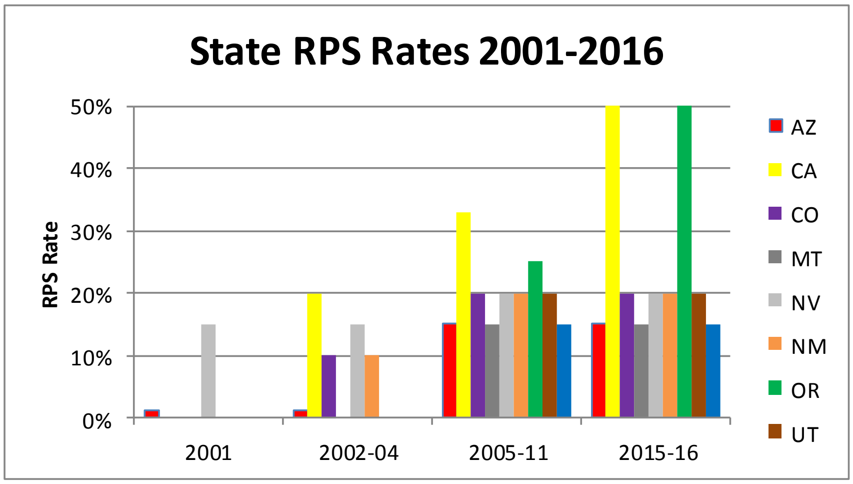
2. Background

A number of important factors contribute to the growth of renewable energy in the electric sector including state and provincial policies, federal tax incentives, and technological innovation that has lowered the cost of wind and solar energy over the past two decades.

State and provincial policies, especially renewable portfolio standards (RPS) policies, have played a critical role in the rise of renewable energy in the Western Interconnection. Since 2001, nine of eleven Western states adopted RPS requirements. Each state has its own RPS policy with distinct and unique features. Many states have increased their RPS percentage rate over time. Figure 1 below depicts the historical progression of the top RPS rates adopted among western states over 4 periods from 2001-2016. In 2001, Arizona and Nevada adopted initial RPS policies with rates of 1.1% and 15%, respectively. In the following three years, California

Colorado and New Mexico enacted RPS statutes that put their top RPS rates at 20%, 10% and 10%, respectively. From 2005-2011, nine states had RPS policies with top rates ranging from 15% to 33%. In 2015-2016, two states significantly increased their RPS requirements as part of the broader policy objective of reducing greenhouse gas (GHG) emissions. California adopted SB 350 which increased its RPS target to 50% in 2030 from the previous mandate of 33% in 2020. Oregon passed SB 1547 which raised its top RPS rate to 50% in 2040 from its previous top rate of 25% in 2025.

Figure 1.



British Columbia and Alberta have also adopted provincial policies that promoted renewable energy development. In 2007, the BC Energy Plan committed British Columbia to clean or renewable electricity production for at least 90 percent of total generation, and all new electricity generation will have net zero greenhouse gas emissions.[1] In 2015, the Alberta Climate Leadership Program set a provincial policy to retire all existing coal plants by 2030 and require that renewable energy account for 30% of generation by 2030.[2]

Renewable energy is playing a significant and growing role in the Western Interconnection. In 2015, the Western Electricity Coordinating Council (WECC) reports that renewable energy was 83,400 GWh or 10% of net electric generation in the Western Interconnection. The remaining shares of generation come from fossil fuels consisting of gas, coal and other thermal (60%), hydro 23%, and nuclear 7%. See Table 1.

---

[1] The BC Energy Plan: A Vision for Clean Energy Leadership, 2007. http://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/bc_energy_plan_2007.pdf.
[2] Alberta Climate Leadership Plan, 2015. http://www.alberta.ca/climate-coal-electricity.aspx .

Table 1.

Western Interconnection Net Generation 2015		
	GWh	%
Gas	266,300	32%
Coal	216,900	26%
Other Thermal	17,100	2%
Hydro	196,600	23%
Nuclear	60,200	7%
Renewables	83,400	10%
Total	840,500	100%

WECC develops a Common Case that represents the expected 10-year future with a generation mix that is consistent with state and provincial policies. For the most recent 2026 Common Case, the amount of renewable energy to meet existing RPS policies would amount to over 204,830 GWh or 20% of the expected 2026 loads. See Table 2.

Table 2.

State/ Province	2026 Load Forecast (GWh)	2026 Sales* Forecast (GWh)	2026 RPS Energy Requirement (GWh)	RPS Rates Applicable in 2026	Maximum RPS Rates Under Existing Policies
AB	118,389	111,286	33,386	30%	30% in 2030
AZ	97,821	91,952	7,964	15%	15% in 2025
BC	72,870	68,498		N.A.	
CA	279,914	248,582	107,120	43%	50% in 2030
CO	65,497	61,567	12,180	30%, 20%, 10%	30% in 2020
ID	30,918	29,063		N.A.	
MEX	15,325	14,406		N.A.	
MT	15,501	14,570	1,204	15%	15% in 2015
NV	44,036	41,393	9,192	25%	25% in 2025
NM	19,184	17,412	2,689	20%, 10%	20% in 2020
OR	55,524	52,193	10,970	27%, 25%, 10%, 5%	50% in 2040
TX	7,458	7,011	379	5%	
UT	37,528	35,277	7,028	20%	20% in 2025
WA	113,710	106,887	12,719	15%	15% in 2020
WY	20,802	19,553		N.A.	
Total	**994,476**	**919,649**	**204,830**		
RPS%	20.6%	22.3%			

* Loads denote expected net generation by producers. Sales reflect consumption by consumers.
Loads differ from sales based on the amount of electric losses in transmission and distribution.

The potential implementation of the Clean Power Plan would likely lead to additional modest increases of renewable energy in the 2030 timeframe. Potential future policies to reduce GHG emissions could become a driver to significantly increase the penetration of renewable energy in the electric sector. Climate scientists investigating long term scenarios to attain the target of limiting global warming to 2 degrees Celsius above pre-industrial levels calculate that it would require an 80% reduction in GHG emissions.[3] Under the United Nations Framework Convention on Climate Change (UNFCC), nations around the globe in 2015 made formal pledges known as

[3] Intergovernmental Panel on Climate Change, Fourth Assessment Report, Climate Change2007. https://www.ipcc.ch/publications_and_data/ar4/wg3/en/ch3s3-es.html

Intended Nationally Determined Contributions (INDCs) to address climate change in 2020 and beyond. The United States submitted a pledge to reduce GHG emissions 26-28% below 2005 levels by 2025.[4] Studies exploring aggressive decarbonization pathway targets in the electric sector indicate that renewable energy penetration levels may have to reach 75% to 80% in the Western Interconnection to meet such 2050 targets.[5]

The ability to integrate increasing levels of renewable energy in the power system has become a critical question and the subject of a growing body of research. Here is a brief overview of some of those studies examining the portions or most of the Western Interconnection.

> **Western Wind and Solar Integration Study Phases 1, 2 and 3.[6]** The Western Wind and Solar Integration Study (WWSIS) Phase 1 performed production cost modeling and operational analysis of the WestConnect[7] region and the Western Interconnection with a 35% renewable energy penetration for the year 2017. The study found that it was operationally feasible to integrate 35% renewable energy provided the implementation of a number of operational reforms such as virtual balancing area consolidation, sub-hourly scheduling, using wind and solar forecasting, and other measures. WWSIS Phase 2 examined the impact of wear-and-tear costs and emission rates on the fossil-fuel fleet from increased ramping with higher penetrations of renewable energy. The Phase 2 study found that the fossil-fuel fleet had an increase operation and maintenance costs per MWh of generation (2%-5%) due to cycling but this was small compared to the fuel savings of using renewable energy. The small increase of emissions from cycling the fossil-fuel fleet was more than offset by the reduction in emissions from using zero emission renewable generation. WWSIS Phase 3 applied traditional reliability tools and analysis of frequency response and transient stability under conditions of high levels of renewable generation in the Western Interconnection.
>
> **Investigating a Higher Renewables Portfolio Standard in California**.[8] This study explored the operational challenges and potential consequences of increasing California's RPS rate from 30% to 50% by the year 2030. Energy and Environmental Economics (E3) used its Renewable Energy Flexibility (REFLEX) model deployed on ECCO

[4] White House Fact Sheet: U.S. Reports its 2025 Emissions Target to the UNFCCC, 2015. https://www.whitehouse.gov/the-press-office/2015/03/31/fact-sheet-us-reports-its-2025-emissions-target-unfccc

[5] Deep Decarbonization Pathways Project High Renewables Case, cited in Western Interconnection Flexibility Assessment, at 3-4. http://deepdecarbonization.org/countries/#united-states

[6] GE Energy, Western Wind and Solar Integration Study Phase 1, 2010. http://www.nrel.gov/docs/fy10osti/47434.pdf;
NREL, Western Wind and Solar Integration Study Phase 2, 2013. http://www.nrel.gov/docs/fy13osti/55588.pdf; GE Energy, Western Wind and Solar Integration Study Phase 3, 2014. http://www.nrel.gov/docs/fy15osti/62906.pdf

[7] WestConnect is a group of transmission providers that at the time of this study included 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 WestConnect footprint covered all or parts of Arizona, Colorado, Nevada, New Mexico, and Wyoming.

[8] Investigating a Higher Renewables Portfolio Standard in California, Energy and Environmental Economics, 2014. https://ethree.com/documents/E3_Final_RPS_Report_2014_01_06_with_appendices.pdf

International's ProMaxLT platform. The REFLEX model performed probabilistic simulations of scenarios with RPS renewable levels of 33%, 40% and 50%. Four 50% RPS renewable scenarios evaluated different renewable mixes characterized as large solar, small solar, rooftop solar, and diverse renewables. Modeling results showed that the 50% RPS scenarios in 2030 resulted in persistent overgeneration in California if operational practices are not changed to tap into the physical flexibility that exists in the electric system. The case representing current procurement trends (50% RPS large solar case), showed high levels of renewable curtailment for 20% of the hours of the year and 9% of the renewable generation. The study proceeded to evaluate five options to reduce renewable curtailment: (1) improved regional coordination; (2) conventional demand response; (3) advanced demand response; (4) energy storage; and (5) diversifying the renewable resource portfolio. These options, except for conventional demand response, were effective to reduce curtailment to 4% or lower.

Low Carbon Grid Study: Analysis of a 50% Emission Reduction in California.[9] The Low Carbon Grid Study (LCGS) examined grid operation impacts of alternative scenarios designed to achieve a 50% reduction in carbon emissions in the California power sector. The National Renewable Energy Laboratory (NREL) performed the analysis on behalf of the Center for Energy Efficiency and Renewable Technologies and supporting sponsors. NREL used the PLEXOS production cost model to evaluate the power sector operations in California and the rest of the Western Interconnection for the year 2030. The study modeled 23 scenarios to better understand the effects of diversifying the renewable portfolios, energy efficiency, demand response, energy storage, and improving grid flexibility. Modeling results showed that California could reach a 50% reduction of CO_2 emissions under most scenarios. The scenario assumptions about grid flexibility made a significant difference in the resulting level of curtailment of renewable generation. A high solar renewable mix under conventional flexibility assumptions resulted in more than 9% curtailment of renewable generation compared to the 0.5% curtailment for the enhanced grid flexibility case. A combination of sources contributed to meeting the steepest 11 GW ramp for the year including physical imports, storage, gas fleet, and demand response.

Western Interconnection Flexibility Assessment.[10] The Western Interconnection Flexibility Assessment explored the operational flexibility of a high level of renewable generation across the U.S. portion of the Western Interconnection. The Western Electricity Coordinating Council (WECC) and the Western Interstate Energy Board jointly sponsored the study performed by E3 and NREL. The study started with a

[9] National Renewable Energy Laboratory, Low Carbon Grid Study: Analysis of 50% Emission Reduction in California, 2016. http://www.nrel.gov/docs/fy16osti/64884.pdf
[10] Energy and Environmental Economics, Western Interconnection Flexibility Assessment, 2015. https://www.wecc.biz/Reliability/WECC_Flexibility_Assessment_Report_2016-01-11.pdf.

> resource adequacy check on WECC's 2024 Common Case using a loss-of-load probability model. A high renewables case was developed by increasing renewables to higher target levels across 5 distinct regions that were expected to stress system flexibility. E3's REFLEX model was run on the PLEXOS platform to perform probabilistic simulations of the power system. Modeling results showed that the solar dominated regions of California and the Southwest exhibited a regular diurnal pattern of high mid-day solar output that resulted curtailment levels approaching 9% and 8%, respectively. The Northwest was challenged to integrate its wind output with a large hydro-dominated system that both reach seasonal peaks during the spring. More detail on the regional results are in the following section.

This paper draws upon the Western Interconnection Flexibility Assessment and other relevant studies to explore the challenges and potential solutions of integrating renewables across the Western Interconnection.

3. Challenges of Renewable Integration

Increasing the amount of renewable energy into the power system can lead to operational challenges. The extent of the challenge, however, is not a simple linear function of the percentage of renewable power in the power system. There are many factors that can influence the ability to integrate renewables. It is important to consider: (a) the types of renewable technologies and mix in a resource portfolio; and (b) the flexibility of the rest of the power system with its physical capability and institutional constraints to meet fluctuations in loads minus renewable generation (net loads).

Different renewable technologies have different patterns of output over daily and seasonal periods. Solar dominated regions have a diurnal pattern of increasing solar energy during the day and then tapering off into the evening. This pattern will hold fairly consistently over different seasons. Wind dominated regions will have a more variable daily pattern depending on the weather patterns. Wind in the western United States generally provides more seasonal fluctuations with highest levels in the spring and lower levels during the summer.

The flexibility of the rest of the power system will also be a critical factor in the ability to meet changes in net loads. The physical capabilities of other generators in the system are important for flexibility. Gas combustion turbine generators are designed for meeting fast ramping and peak periods. Older gas combined cycle generators were designed to operate for longer periods of time to reach efficient operations. New gas-fired generators have the capability to quickly ramp up and down to meet changing levels of net load. By contrast, coal generators have typically been used as baseload generators with more limited capability to ramp up or down. An individual hydro generator may have the technical capability to increase or decrease its output, but when operated in the context of a broader river system, there may be less operational flexibility to control water flows down a river system, especially if there are other environmental constraints imposed on water flows.

Institutional operating practices can impose constraints that reduce the potential least cost dispatch. A power system organized over a small footprint or fragmented in small units across a larger footprint constrains least cost dispatch of resources. Similarly, a market structure based on bilateral contracting among parties can also hinder system-wide efficiency and flexibility. Other types of institutional constraints can also reduce the potential flexibility of the power system.

Some of the most challenging periods for system operators are during low loads with high renewable generation. This combination reduces net loads to very low levels that can force much of the fossil fleet to either shut down or go to minimum generation levels. Operators need to keep enough of the fossil fleet ready to meet anticipated ramps for the start of a new work day or to respond to a sudden drop of renewable output.

The above factors interact in unique combinations for different regions across the Western Interconnection. Results from the 2015 Flexibility Assessment study provide insights on how five regions across the Western Interconnection would be able to integrate higher levels of renewables.

The Flexibility Assessment study developed a high renewables case which was purposefully designed to stress the system and evaluated using sophisticated probabilistic modeling techniques. The starting point for this case was the 2024 Common Case which was evaluated to ensure there were sufficient resources to meet resource adequacy requirements of a loss of load probability standard. Renewables were then added to each reach region consistent with the Common Case portfolio mix until the target penetration level was reached. The high renewable case featured penetration levels across the five regions as follows: Basin 40%, California 50%, Northwest 30%, Southwest 40%, and Rocky Mountains 40%. See Figures 2 and 3 below.

Figure 2

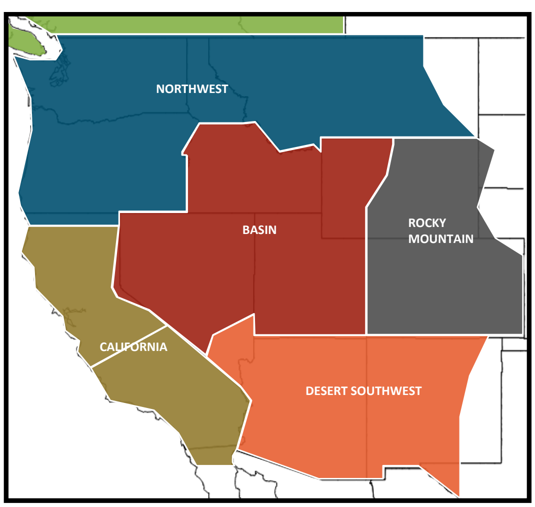
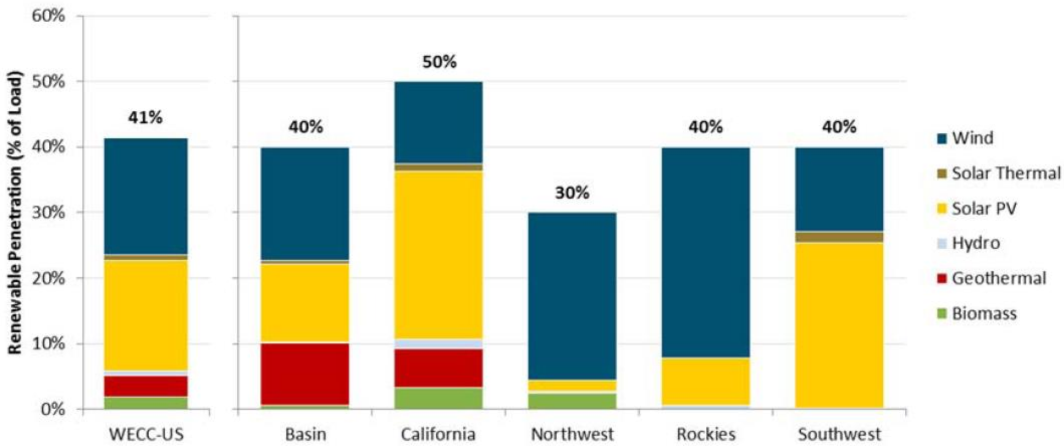


Figure 3



Under the Flexibility Assessment modeling, the high renewables case specified a 41% penetration of renewables across five regions covering the western states in the Western Interconnection. While there are important variations across the five regions, each region was able to integrate the very high penetration of renewable energy targeted under this study while maintaining resource adequacy and reliable operations. Renewable curtailment provides a "relief value" which serves as a last resort for operators who have exhausted their flexibility in real time to balance load and generation. Collectively across the five regions, renewable curtailment amounted to 6.4 percent of renewable generation.

California. Modeling results of California with a 50% renewable penetration level under the high renewables case are depicted in Figure 4(a). A key finding is the high amount of surplus generation that is curtailed on a daily and annual basis. Surplus generation that cannot be delivered to loads or exported is curtailed. The average spring day depicted shows a large diurnal pattern of curtailed energy. For the year, 8.7% of the renewable generation is curtailed and curtailment occurs in 20% of the hours during the year. The mid-day curtailment pattern becomes the most severe during the spring months and to a lesser extent during the fall and winter months. This high level of curtailed renewable energy is a function of the resource mix and operational parameters assumed in this case.

The renewable mix specified for California in this case consists of about 50% solar, 25% wind, and a mix of geothermal, biomass and small hydro for the remainder. The large amount of solar PV generation leads to a diurnal pattern of increasing generation during the morning, peaking mid-day and declining in the evening. The gas fleet follows an inverse pattern of the solar fleet. Gas generation declines during the morning, hits minimum operating levels mid-day, and increases for the evening ramp. Hydro, imports, and storage resources also contribute to meeting the morning and evening ramps in net load.

Three important modeling assumptions in this study serve to constrain the operational flexibility in the California power system. First, the California generation fleet modeled in this study includes "must run" generation[11] including the Diablo Canyon Power Plant (2,160 MW) and the fleet of non-dispatchable cogeneration resources (4,721 MW). Second, the California power system was modeled with a minimum generation requirement that requires 25% of local loads be met with qualifying thermal resources. Third, transmission line flows were constrained to its historically observed range rather than its physical capacity limits. If these three modeling assumptions overstate the inflexibility of California power system, the modeling results will overstate the projected level of renewable curtailment. Since the release of this study, the owner of Diablo Canyon announced that it will fully retire the nuclear plant in 2025. Additionally, the California ISO has replaced its 25% minimum generation requirement planning assumption with a less constraining rule.

Southwest. Modeling results of the Southwest region with 40% renewables are shown in Figure 4(b). Similar to California, the Southwest region exhibits the diurnal pattern of mid-day curtailment but to a lesser degree. The Southwest has 7.3% of its annual renewable generation curtailed and the incident of curtailment occurs in 13% of the hours in the year. The seasonal curtailment pattern is also the most severe during the spring months and to a lesser extent during the fall and winter months. Some of the Southwest curtailment may be the result of ripple effects emanating from surplus generation in California. The renewable mix in the Southwest has a high level of solar with solar PV accounting for about 70% and about 30% from wind. In contrast to California, the Southwest's remaining generation fleet excluding renewables has a larger share of coal and nuclear generation. The traditional practice has been to operate coal and nuclear units as baseload generation. The modeling results of the High Renewables case showed that the coal fleet in the Southwest would have an average of four start-ups and shutdowns per month over the year. During the spring months, coal units start-up nearly 9 times per month. This would be a significant increase of coal cycling over the traditional operations. If the coal fleet cannot operate with such flexibility, it will need to be replaced by gas generation during those months or the levels of renewable curtailment in the Southwest would be higher than the High Renewables case indicates. The challenge for the Southwest to integrate high levels of solar PV is to find flexibility in the coal fleet, substitute more flexible thermal generation for the coal and nuclear fleet, or other measures such as institutional reforms or storage to improve system flexibility.

Northwest. Modeling results for the Northwest region with 30% renewable penetration are shown in Figure 4(c). The Northwest operations lead to curtailment of 5.6% of its annual renewable generation which occurs over 10% of the hours in a year. The unique feature of the Northwest is the large role of the hydro system which peaks during the spring run-off period and

[11] "Must run" generators refer to those electric generators that have physical or reliability-based constraints that limit the ability of the generator to decrease or increase their output over short periods of time. For example, large nuclear generating stations typically cannot be operated to start up and shut down repeatedly, or ramp up and down during a day.

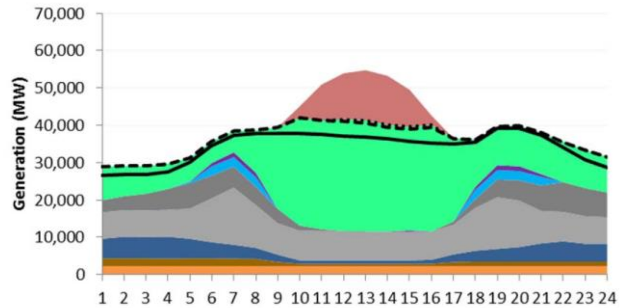
can vary significantly from high-hydro years to low-hydro years. The renewable mix in the Northwest was assumed to be 70% wind and the remainder from biomass and solar. The potential for renewable energy curtailment corresponds to the overlap between the hydro system and wind generation. Wind does not have the daily diurnal patter that solar PV creates in California and the Southwest. Wind patterns can change with daily weather variations. Wind tends to be strongest during the spring which coincides with the hydro system seasonal peak. In the Northwest, surplus hydro generation has historically been exported to other regions. Under the High Renewable case, the increase of wind generation creates additional surplus generation that increases curtailment. The increase of renewables in other regions creates an additional complication as other regions that may have imported hydro generation are experiencing their own oversupply problems, and leads to further curtailment in the Northwest.

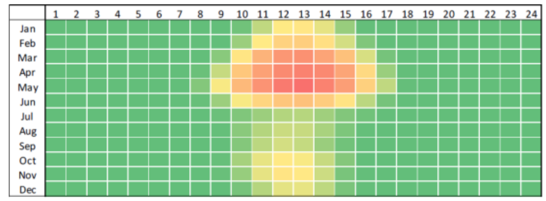
Basin. The High Renewables case assumed a 40% penetration level for the Basin region with results depicted in Figure 4(d). Curtailment in the Basin region amounted to 0.1% annual renewable generation and it occurred 1% of the hours in a year. An important factor contributing to the low curtailment in Basin is its diverse renewable mix. Basin's renewable shares are wind 45%, solar 30%, and geothermal 25%. Each of these technologies has a different temporal profile that effectively spreads the total renewable generation around more evenly over time and reduces the incidence of over supply events. The 30% solar PV does contribute to the diurnal increase of renewables but within the bounds of the non-renewable fleet to ramp down. Similar to the Southwest, coal generation is a sizeable portion of the Basin non-renewable generation fleet. If coal units have less flexibility to cycle as modeled in the High Renewables case, the amount of curtailment in Basin would increase to higher levels.

Rocky Mountains. Results for the Rocky Mountain region are shown in Figure 4(e). Similar to Basin, the Rocky Mountain region was modeled at a 40% renewables penetration level and it encountered very low levels of curtailment. Curtailment accounted for 0.1% of the annual renewable generation and the frequency of curtailment was 1% of the hours in a year. The Rocky Mountain renewable portfolio contained 80% wind with most of the remaining share from solar PV. Wind dominated regions do not have a typical daily pattern. The more relevant challenging periods for the Rocky Mountains is during periods of high winds which can account for a high percentage of generation, and large ramps up and down on the system. Most of the non-renewable generation fleet consists of gas and coal generation. The combination of thermal units ramping, pumped hydro storage operations, and exporting surplus generation during the early morning and late evening periods serves to minimize renewable curtailments.

Figure 4. High Renewables Case on 5 Regions for Average Spring Day and Curtailment Impacts

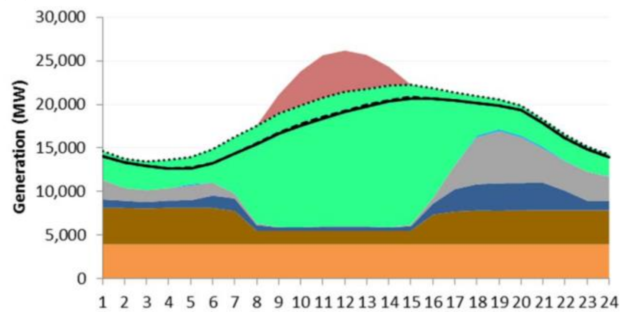
(a) California

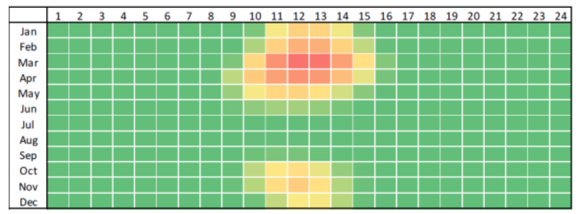




Renewable Penetration (% of load)	Renewable Curtailment (% of annual renewables)	Curtailment Frequency (% of hours per year)
50%	8.7%	20%

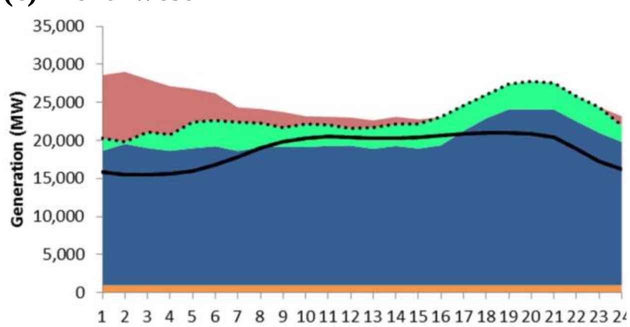
(b) Southwest

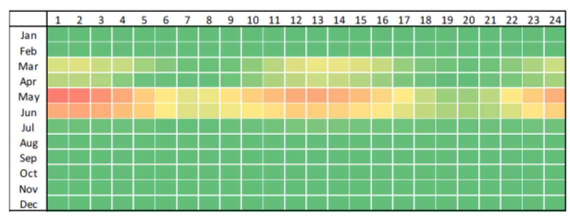




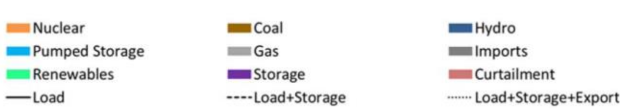
Renewable Penetration (% of load)	Renewable Curtailment (% of annual renewables)	Curtailment Frequency (% of hours per year)
40%	7.3%	13%

(c) Northwest

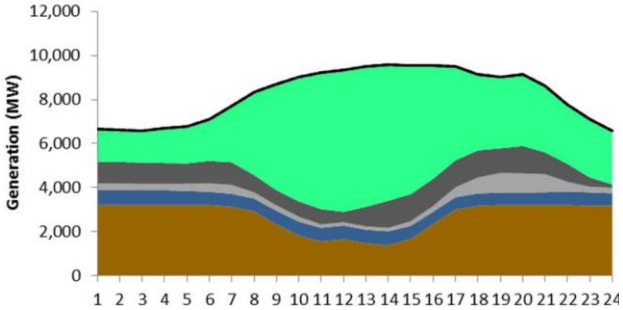




Renewable Penetration (% of load)	Renewable Curtailment (% of annual renewables)	Curtailment Frequency (% of hours per year)
30%	5.6%	10%

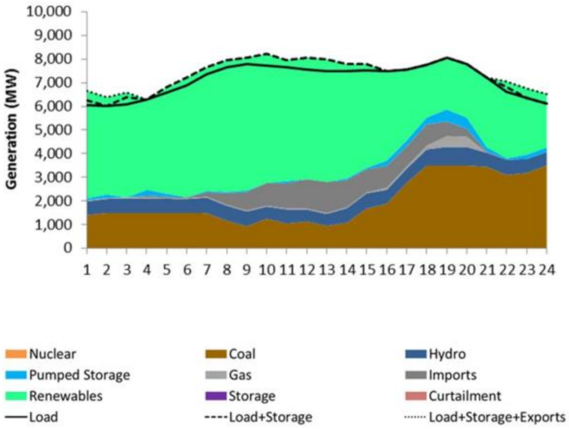


(d) Basin



Renewable Penetration (% of load)	Renewable Curtailment (% of annual renewables)	Curtailment Frequency (% of hours per year)
40%	0.4%	1%

(e) Rocky Mountain



Renewable Penetration (% of load)	Renewable Curtailment (% of annual renewables)	Curtailment Frequency (% of hours per year)
40%	0.1%	1%

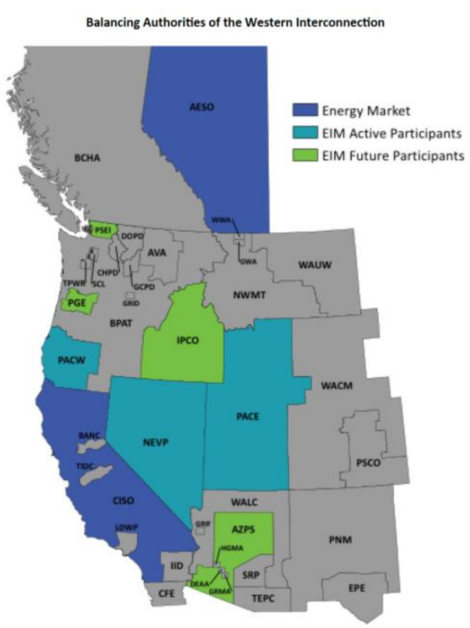
4. Options for Renewable Integration

There are a number of potential steps to improve the flexibility of the power system to integrate variable renewable energy. This section focuses on five potential options: regional coordination, renewable diversity, storage, advanced demand response, and thermal fleet and institutional flexibility. These options represent potential steps that policy makers and regulators may want to consider to improve the power system flexibility in order to more efficiently integrate renewable integration. While this list is not an exhaustive list of potential action items, it does attempt to capture some of the most important topics and reflect the emerging key issues with a changing resource mix in the electric power system. These changes are contributing to a paradigm shift from electric system planning from a focus on peak reliability to planning around the economics of renewable integration.

4.1. Regional Coordination

Today, the Western Interconnection operates within a disaggregated institutional structure of 38 different Balancing Authorities (BAs). See Figure 5. BAs are responsible for dispatching generation to meet loads in their respective area and maintaining reliability. Seven BAs are generation only BAs with no loads. Two BAs operate with full energy markets: the California Independent System Operator (CAISO) and the Alberta Electric System Operator (AESO). Outside of the CAISO and AESO, power trading across the remaining 36 BAs has historically occurred through bilateral transactions between buyers and sellers. Bilateral trades that send power through multiple BA territories incur transmission charges that serve to increase the cost and complexity of executing trades in an integrated power system.

Figure 5.

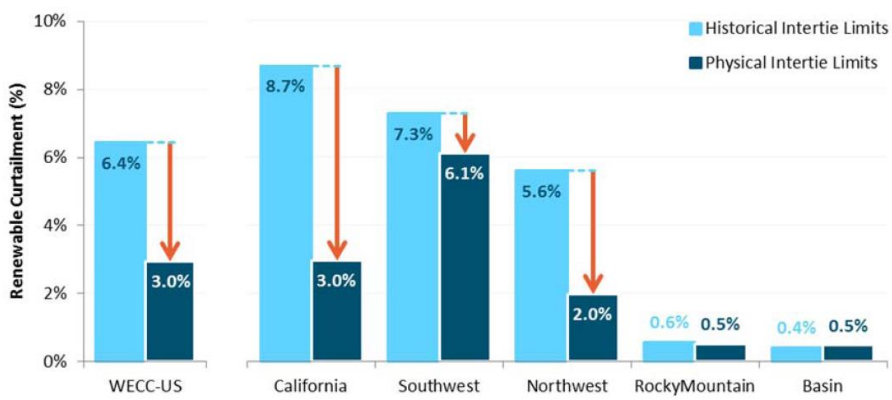


Study Findings. The 2010 Western Wind and Solar Integration Study Phase 1, the first major interconnection-wide analysis of integrating renewables, identified regional coordination as its first recommendation for solutions to address high penetrations of renewable energy.

The 2015 Flexibility Assessment study performed an interesting sensitivity analysis that illustrates the potential gains from improved regional coordination. A proxy method for representing better regional coordination was to increase the transmission intertie limits that link the five regions modeled in this study (Basin, California, Northwest, Rockies and Southwest). The baseline intertie limits were initially set at historical observed flow levels. This regional coordination sensitivity raised the intertie limits from the historical flow level to the physical limits of the paths. Relaxing the intertie constraints makes it easier for regions to trade with other regions during a day or season across the entire Western Interconnection. A region with surplus renewable generation would be able to export low-cost power to another region. An importing region could use lower cost imports and back down more expensive thermal generation. Expanding the footprint of operations provides more diversity of the renewable portfolio and a great pool of loads to absorb the generation. Raising the intertie limits to their physical limits served as a proxy for other measures that could also improve regional coordination such as institutional operating changes, creation of new energy markets, and expanding the transmission system.

Modeling results of the regional coordination sensitivity in the Flexibility Assessment study showed that increasing the intertie limits to their physical limits served to reduce the amount of renewable curtailment across the Interconnection from 6.4% to 3.0%. See Figure 6. The three regions with the highest initial curtailment levels would have larger reductions: California from 8.7% to 3.0%; Southwest from 7.3% to 6.1%, and the Northwest 5.6% to 2.0%.

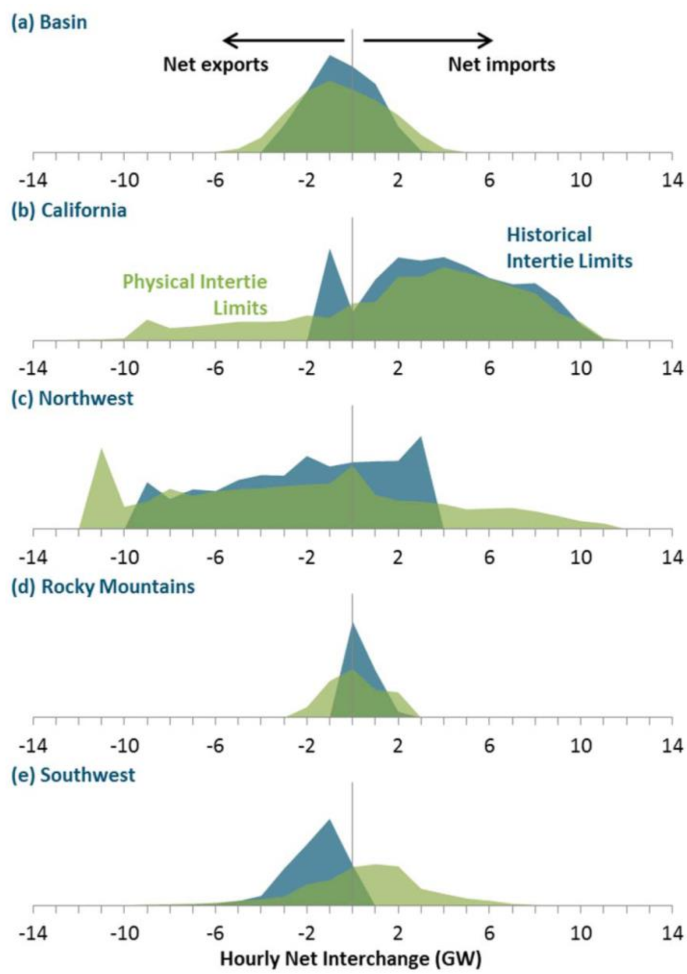
Figure 6.



Regional coordination that reduces the constraints on trade across the regions leads to a reallocation of resources that lowers total costs across the system. In this application, a high renewables future leads to interesting shifts in the pattern of historic power flows. See Figure 7 for the changes in flows across the regions caused by a reduction in the intertie limits of the five regions.

- California, a traditional net importer, would export surplus renewable generation to other parts of the Interconnection at times over the year.
- The Northwest, a traditional next exporter, becomes a net importer during certain periods as it absorbs the inexpensive California surplus generation.
- The Southwest, a traditional net exporter, has a significant increase of imports over the year. The Southwest imports surplus generation from California during periods of the year, as well as surplus generation in the Northwest that flows south through California and into the Southwest.
- Both Basin and the Rocky Mountain regions participate in more power trading that shifts the distribution of net exports wider and roughly equal in both directions.

Figure 7



Application. Over the past five years, a number of initiatives have explored steps to improve regional coordination. Utilities in the Northwest Power Pool collaborated on proposals under the MC Initiative. Entities in the southwest formed the Southwest Variable Energy Resources Initiative to facilitate the integration of higher levels of renewables. State regulatory commissioners organized the PUC EIM Group to investigate the potential benefits and costs of an energy imbalance market.

In November 2014, the CAISO and PacifiCorp launched the Energy Imbalance Market (EIM) that provides real time energy trading between the CAISO and PacifiCorp's two balancing authorities. NV Energy joined the EIM in December 2015. Arizona Public Service and Puget Sound Energy are the two most recent participants to join the EIM in October 2016. Portland General Electric and Idaho Power plan to enter the EIM in 2017 and 2018, respectively. Additional entities that have announced their intent or interest in the EIM are the Balancing Authority of Northern California (BANC), Sacramento Municipal Utility District, and Mexico's electric system operator El Centro Nacional de Control de Energia (CENACE). [12]

In the third quarter of 2016, the EIM operations yielded an estimated $26.16 million of gross benefits. The EIM's cumulative estimated gross benefits since operations began in November 2014 to the third quarter 2016 are $114.35 million.[13] Benefit calculations are based on gains from more efficient dispatch of generation resources across the participating BAs, reduced renewable energy curtailment, and reduced reserves needed to integrate variable renewable resources. The benefits of the EIM footprint will likely increase as the EIM footprint expands with the addition of more utilities, more generating resources, and larger loads.

In 2015, PacifiCorp and the CAISO announced an agreement to explore the feasibility and benefits of PacifiCorp joining the CAISO. A number of important institutional and regulatory issues must be resolved before PacifiCorp could operate the CAISO energy market. If the proposal moves forward, and other utilities follow, the CAISO could expand into a broader Western regional independent system operator. This would build upon the EIM's real time market operations to include a day-ahead market and greater optimization potential of the generation fleet with the operation of the transmission system.

In 2016, a group of seven utilities within the WestConnect footprint organized as the Mountain West Transmission Group (MWTG) for the purpose of creating a single multi-company transmission tariff and explore creating a "Day 2" regional transmission organization (RTO). The MWTG issued a request for information from different regional entities that could serve as

[12] California Independent System Operator, Energy Imbalance Market Overview, https://www.caiso.com/informed/Pages/EIMOverview/Default.aspx.
[13] California Independent System Operator, Western EIM Benefits Report, Oct. 26, 2016. https://www.caiso.com/Documents/ISO-EIMBenefitsReportQ3_2016.pdf

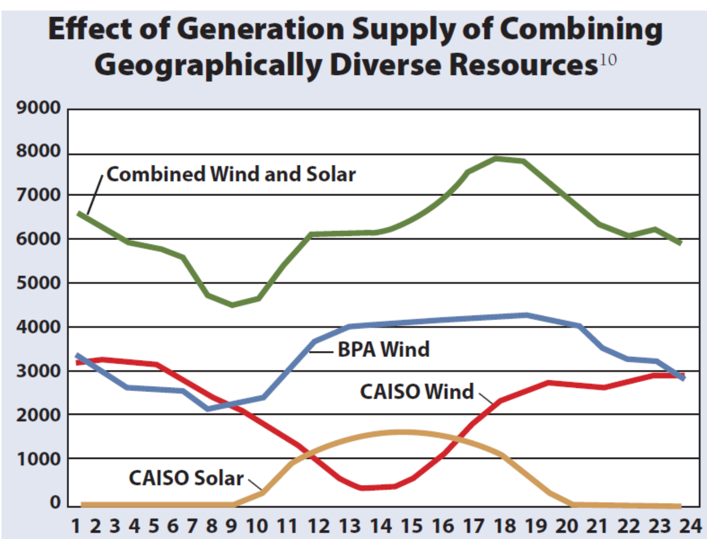
potential regional operator for the MWTG. The MWTG entities will be making important decisions about their objectives and organization over the next 2-3 years.

4.2. Renewable Diversity

Building a diverse renewable portfolio is another option to address the challenge of integrating variable generation. Diversification can take two forms: technology diversity and geographical diversity. Technology diversity implies the use of different renewable technologies with different generation profiles. Solar energy generally provides a regular diurnal pattern with a peak increase in the middle of the day. Wind generation tends to be more variable over the daily cycle but with stronger seasonal output during the spring and fall seasons. Geographic diversity refers to variations in renewable generation across different regions. Different weather patterns, moving storm fronts, and time zone differences will contribute to variations in the output of wind generators located in the western part of the interconnection relative to a wind generator in the eastern part of the interconnection.

Figure 8 below shows the potential impact of combining three different sources of renewables. Wind output from the Columbia River basin in Oregon and Washington (blue line) could be combined with wind generation located in Tehachapi in California (red line) for a complementary geographic mix of wind output. Furthermore, adding solar PV generation in California (yellow line) provides technology diversity that produces the less variable output of the portfolio represented by the green line.

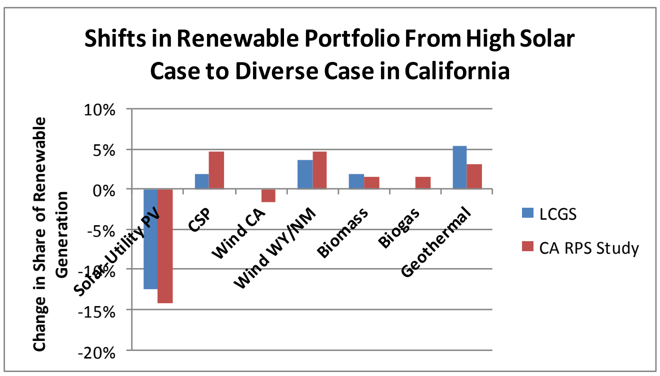
Figure 8.



The potential gains from increasing renewable diversity must be weighed against the relative costs of using potentially more expensive resources. For example, a utility with access to good solar resources may get more solar energy per dollar relative to wind energy. To shift away from solar to wind would increase costs of the portfolio. However, if that utility found that incremental additions of solar were being curtailed or it incurred high costs to integrate more solar, diversifying to wind energy could become the cheaper marginal resource.

Study Findings. Two different studies that examined high renewable penetrations in California provide insight on the contributions of a more diverse renewable portfolio. NREL's Low Carbon Grid Study modeled multiple versions of a 55% renewable scenario including a diverse renewable portfolio and a high solar PV portfolio. E3's California RPS study developed a baseline 50% renewable portfolio with a high level of solar PV to reflect the procurement trend in California. The California RPS study also explored alternative options including a more diverse resource portfolio to reduce the curtailment of renewables. Both of these studies specified a diverse renewable portfolio by reducing PV solar in California and adding wind from Wyoming and New Mexico, concentrated solar power (CSP)[14], geothermal and biomass. See Figure 9 below for the percentage changes in the high solar PV portfolio to the diverse portfolio.

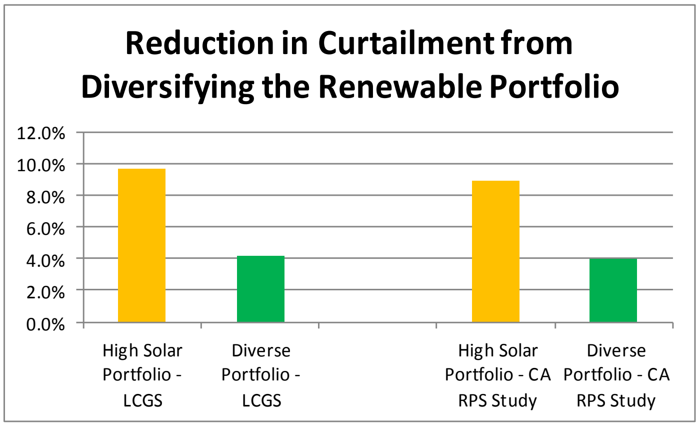
Figure 9



Modeling runs of the high solar cases by the California RPS study and the Low Carbon Grid Study resulted in curtailment of renewable generation equal to 8.9% and 9.7%, respectively. By contrast, the modeling results of the diverse portfolio cases lowered curtailment to 4.0% in the California RPS study and 4.2% in the Low Carbon Grid Study. These two independent studies showed that diversifying a portfolio with a high renewable penetration level can reduce curtailment by more than 50% compared to the high solar case. See Figure 10.

[14] Concentrated solar power (CSP) is a category of solar energy that uses mirrors or lens to concentrate sunlight over a large area to centralized point that heats a fluid solution and drives a turbine.

Figure 10.

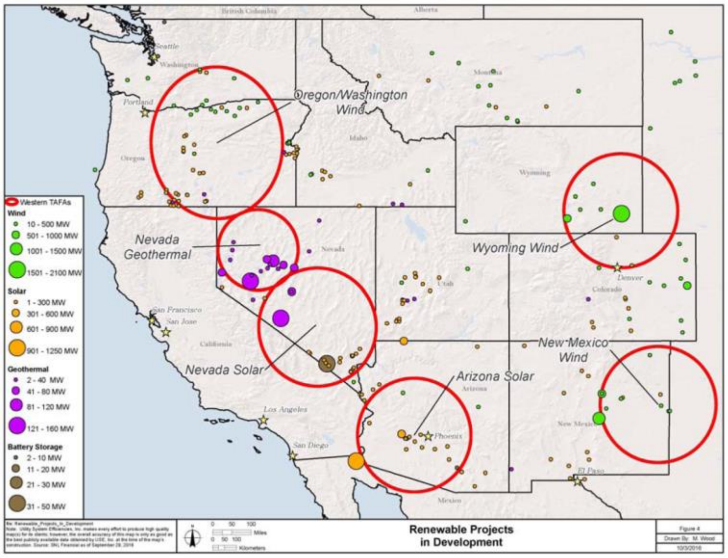


Applications. Diversifying the renewable portfolio can make it easier to integrate variable generation. However, the quality of different renewable technologies differs across the Western Interconnection. The best solar resources tend to be in the southern part of the Interconnection. The highest quality wind resources are in the north and eastern parts of the Interconnection. Some of the best geothermal resources are located in northern Nevada. If the Western Interconnection operated as single optimized market, the highest quality resources would be selected to meet loads across the footprint and use a diverse renewable portfolio.

In the current 38 BA operating structure, many utilities operate in an area where there is a dominant low cost renewable resource such as solar or wind. Utilities can import renewable energy over considerable distance. Dynamic scheduling enables a utility to import renewable energy from a remote resource and integrate it into their operating system as if it were located in their footprint. This can be helpful in developing remote renewables in areas with low loads that may not otherwise be able to absorb a large amount of wind or solar. For example, Arizona Public Service uses dynamic scheduling to bring in wind energy from projects located in New Mexico and integrate the wind into its operations in the Phoenix area. Similarly, the CAISO set up its first dynamically scheduled resource located in Nevada at the Copper Mountain solar project which was located in NV Energy's balancing authority.

In 2016, California's Renewable Energy Transmission Initiative 2.0 (RETI 2.0) has been exploring options to reach its new 50% RPS requirement and integrate the additional renewables with a more diverse portfolio. The process identified areas outside the state for potential renewable energy development and corresponding transmission enhancements known as Transmission Assessment Focus Areas (TAFAs). The TAFA areas identified by the RETI 2.0 process were: wind in the Northwest, wind in Wyoming, wind in New Mexico, geothermal and solar in Nevada, and solar in Arizona. See Figure 11 below.

Figure 11.



4.3.Storage

Energy storage is another option to address the challenge of integrating high levels of renewable generation. Energy storage provides additional flexibility in power operations by shifting the time of generation from the time of dispatch. With storage capability, operators can store renewable energy during periods of surplus and dispatch that energy during times of shortage. This added flexibility has the dual benefit for integrating renewables to meet downward ramps by storing energy and respond to upward ramps by dispatching stored energy.

There are a number of different types of electric storage technologies. Pumped hydro storage systems use two reservoirs at different elevations to alternately store energy in the upper reservoir and release that water to the lower reservoir through a turbine. Pumped hydro is an established technology with about 20 GW capacity of operating facilities in the U.S.[15] Large-scale battery storage is an emerging commercial technology with many different types of battery technologies.[16] Compressed air energy storage (CAES) technology stores energy by inserting compressed air into a large underground storage facility. When the compressed air is released it can run a turbine and dispatch electricity to the grid. There are currently two large operating CAES plants in the world and a number of smaller scale research facilities.[17]

[15] National Hydro Power Association, Pumped Storage. http://www.hydro.org/tech-and-policy/technology/pumped-storage/

[16] Energy Storage Association. http://energystorage.org/energy-storage/energy-storage-technologies

[17] Pacific Northwest National Laboratory.. Two large operating CAES plants are 110 MW in McIntosh, Alabama and 290MW in Huntorf, Germany. http://caes.pnnl.gov/ .

Study Findings. The Flexibility Assessment study provides insights on the potential impact of higher levels of energy storage on integrating renewable energy across the Western Interconnection. Recall that the High Renewables case in the Flexibility Assessment assumed very high penetration levels of 50% in California, 40% in the Southwest, Basin and the Rocky Mountain regions, and 30% in the Northwest region. Under these penetration levels, three regions faced significant amounts of curtailed renewable energy: 8.7% in California, 7.3% in the Southwest, and 5.6% in the Northwest. A storage sensitivity case added 6000 MW of storage resources across three regions: 4000 MW in California, 1000 MW in the Southwest, and 1000 MW in the Basin. Three storage scenarios were modeled assuming 3 different storage duration devices: 2-hour, 6-hour, and 12-hour capabilities.

Modeling results showed there were significant gains in reducing curtailment moving from a 2-hour to a 6-hour duration storage, but no material gains moving from a 6-hour to a 12-hour storage. Figure 12 shows the changes to curtailment in the 6-hour duration storage case. The additions of storage reduced renewable curtailments in the solar PV dominated regions of California (8.7% to 5.7%) and the Southwest (7.3% to 5.1%). By contrast, storage in the wind and hydro dominated Northwest did not reduce curtailment from 6-hour storage, or the 2-hour and 12-hour storage cases. Storage devices were not added in Basin or the Rocky Mountain regions.

Figure 12.

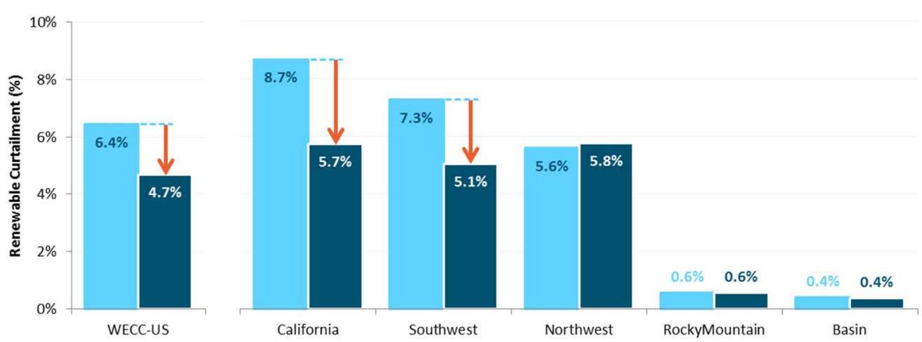
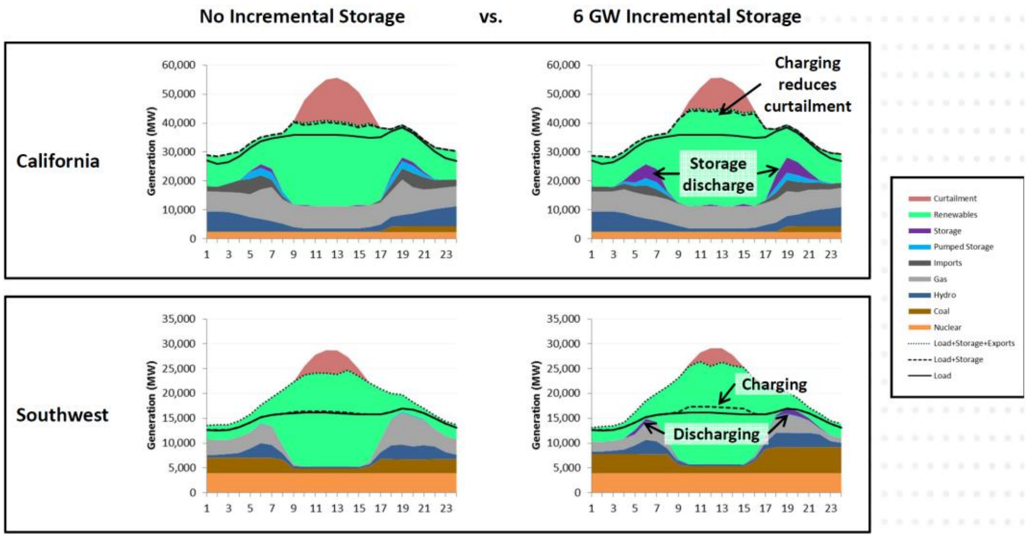


Figure 13 illustrates how the 6-hour duration storage matches with the mid-day curtailment of solar PV renewable generation in both California and the Southwest. The storage devices charge up and store surplus renewable energy to reduce the amount of curtailment for the day. Additionally, the storage devices discharge during the shoulder periods to support the rest of the non-renewable fleet to down ramp in the morning and up ramp in the late afternoon.

In the Northwest, curtailment does not follow the diurnal pattern as it does in California or the Southwest. Surplus generation has different temporal characteristics that are driven by hydro power seasonal levels and wind patterns. Other types of storage devices may well reduce curtailments and provide other benefits for this region.

Figure 13.



Applications. The California Legislature established energy storage procurement goals under AB 2514 in 2013. Under this statutory mandate, the California Public Utility Commission (PUC) adopted an energy storage procurement framework and a storage target for the three investor owned utilities totaling 1,325 MW by the year 2020.[18] California's storage procurement framework was informed by a joint agency collaboration of the CAISO, California PUC and the California Energy Commission that produced a final report known as the Energy Storage Roadmap.[19]

In Washington, the state's Clean Energy Fund supports a number of programs including two utility pilot projects for energy storage. In 2015, Avista started its Energy Storage Project that features a 1 MW and 3.2 MWh large-scale battery system designed to assist in the integration of wind energy in the region. In 2014-15, Snohomish Public Utility District (PUD) installed two battery systems using Modular Energy Storage Architecture (MESA) which allows for building of additional units for expansion. The first set of batteries were installed at a substation located next to the PUD's control center. The objective of the MESA standards is to provide a common, standard-based platform to combine components, simplify the system, and lower costs to the utility.

---

18 California Public Utility Commission. Storage procurement policy enacted by AB 2514 in 2015 and rules established through the PUC under docket 15-03-011. http://www.cpuc.ca.gov/General.aspx?id=3462

19 Advancing and Maximizing the Value of Energy Storage Technologies: A California Roadmap. 2014. https://www.caiso.com/Documents/Advancing-MaximizingValueofEnergyStorageTechnology_CaliforniaRoadmap.pdf

4.4. Advanced Demand Response

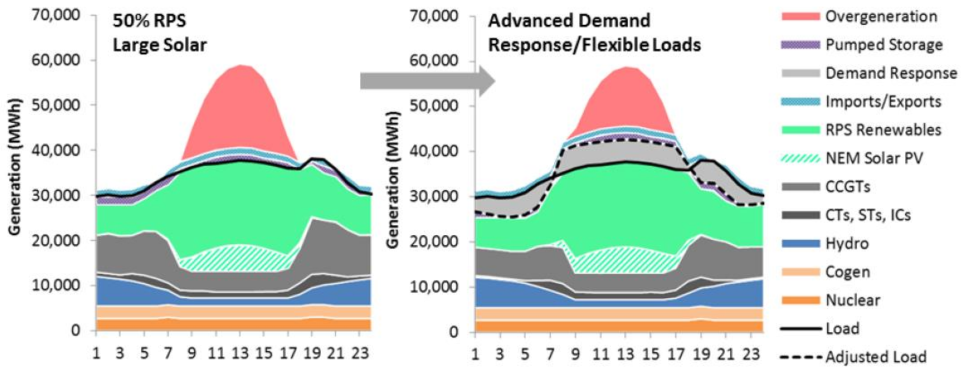
The historical early use of Demand Response (DR) resources was to reduce seasonal peak loads or infrequent price peaks on the system. These applications of DR were typically predictable and limited to a small number of hours during the year. Innovation has expanded the capability of DR resources to operate more frequently through automated communication systems to effectively shift loads from one period to another period. The advanced DR is capable of providing downward flexibility (absorbing energy during a surplus period) and upward flexibility (releasing energy to assist in meeting loads). The advanced DR resources can contribute to system flexibility and assist in the integration of variable energy resources.[20]

Advanced DR resources that would perform to integrate variable energy resources need to have the following features: (1) DR loads must be available for frequent uses such as 100 times per year, and used for at least 1 hour to 10 hours; (2) DR loads must have short response times ranging from 10 minutes to one minute; and (3) DR loads must be connected to two-way communications, automated controls and advanced telemetry.[21] The categories of major end use DR resources include: agricultural pumping, data centers, refrigerated warehouses, residential water heaters, wastewater pumping, commercial heating and cooling, municipal pumping, residential cooling, and electric vehicles.

Study Findings. E3's 2013 California RPS study modeled the impact of adding 5 GW of advanced DR loads to the California system assuming a 50% high renewables case with heavy reliance on solar in 2030. Advanced DR was modeled as a load modifier with daily constraints. DR resources can increase or decrease by 5 GW over the day but the net energy change is constrained to zero in a day. Figure 14 below presents the case of a 50% RPS on the left, and the 50% RPS with advanced DR resources. During the mid-day period with high levels of solar and surplus generation, DR is absorbing energy and pushing the adjusted load level higher and reducing the amount of surplus generation. During the morning and evening periods, DR is releases energy and reduces adjusted loads. The lower adjusted loads in the morning and evening hours reduces the morning down ramp and the evening upward ramp on the thermal fleet. The level of curtailed energy drops from 9% in the high RPS case to 4% in the advanced DR case.

[20] Energy and Environmental Economics, Inc. Investigating a Higher Renewable Portfolio Standard in California, 2014, at 121-122. https://ethree.com/documents/E3_Final_RPS_Report_2014_01_06_with_appendices.pdf
[21] Enernoc, Inc., "The Role of Demand Response in Integrating Variable Energy Resources, 2013, at vi. http://www.westernenergyboard.org/sptsc/documents/12-20-13SPSC_EnerNOC.pdf

Figure 14.



Application. In a study for the Western Interstate Energy Board, the consultant firm Enernoc estimated the potential of DR resources for variable integration purposes across the interconnection for the year 2020 for an average hourly load summer weekday. The load reduction potential was estimated to be 3.3 GW for providing contingency reserves, 2.6 GW for providing load following services, and 1.8 GW for providing regulation services. Table 3 shows the load following potential by state and province for a typical summer day in 2020. Further into the future, the potential size of DR resources is likely to increase with new technologies, new equipment standards, new building codes, and the growth the electric vehicles. Electric vehicles were not a significant source of DR for the timeframe of the Enernoc study.

Table 3. Load Following Potential by States/Provinces in Typical Summer Day in 2020 (MW)

	Residential		Commercial		Industrial		Total	
State/Province	Load Dec.	Load Inc.	Load Dec.	Load Inc.	Load Dec.	Load Inc.	Load Dec.	Load Inc.
Alberta	13	2.5	87	51.9	15	0.2	**115**	**55**
Arizona	414	4.1	130	69.8	19	0.4	**563**	**74**
British Columbia	27	5.3	76	45.2	16	0.3	**119**	**51**
California	256	3.6	498	245.5	99	2.2	**853**	**251**
Colorado	24	1.4	101	64.7	19	0.3	**144**	**66**
Idaho	17	1.2	30	19.2	3	0.1	**51**	**21**
Montana	10	0.7	25	15.7	2	0.1	**37**	**16**
New Mexico	54	0.6	41	21.7	3	0.1	**98**	**22**
Nevada	91	1.1	40	21.1	9	0.2	**139**	**22**
Oregon	23	4.4	73	43.2	12	0.2	**107**	**48**
Utah	18	1.3	46	24.7	11	0.2	**75**	**26**
Washington	42	8.2	136	81.0	33	0.4	**211**	**90**
Wyoming	6	0.4	22	13.7	2	0.0	**30**	**14**
Total	**995**	**34.6**	**1,304**	**717.6**	**243**	**4.6**	**2,542**	**757**

The 2016 Low Carbon Grid Study modeled the potential contribution of electric vehicles as a DR resource in California for the year 2030. Electric vehicles were assumed to increase annual loads by 12.9 GW in 2030. Half of the vehicles were specified with fixed charging profile and the other half had a flexible recharging profile that is price-responsive and advantageous for the electric utility. The combined fixed and flexible electric fleet would contribute over 3 GW of mid-day loads that would absorb high levels of solar PV generation.

In summary, E3's modeling showed the potential for advanced DR that could shift large amounts of power from one period in the day to another period in the same day. The Enernoc study quantified different types of DR resources with different characteristics that could be available in western states. Further research would be helpful to further assess the longer time horizon of 5 years of advanced DR's potential to reduce renewable curtailment.

4.5. Thermal Fleet and Institutional Flexibility

Increased flexibility of the natural gas fleet and the coal fleet can contribute to high levels integrating renewable generation. The conventional dispatch strategy relied on coal generation as a base load resource to operate with high capacity factors. The natural gas fleet was dispatched on top of the baseload to meet higher level loads and provide the ramping capability to changing loads over a typical day.

Within the natural gas fleet, combined cycle gas turbines (CCGT) were the efficient work horse units that provided the mid-level dispatch over longer periods than less efficient gas units. The combustion turbine (CT) is built for fast ramping and peak hour capability to meet subhourly fluctuations. In recent years, manufacturers have designed more flexible gas generators. New areoderivative combustion turbines provide fast ramping capabilities. Newer combined cycle units have more flexibility ramp up and down and have fewer constraints between starts. Table 4 compares key operating factors of a representative existing, older, fleet-wide average combined cycle unit, an existing fleet-wide average combustion turbine unit, and a new flexible combined cycle unit. The newer combined cycle units have faster ramp rates, less restrictive up times and down times, and can maintain lower stable levels of output.

Table 4. Gas generator specifications for existing and new flexible units.

Parameter	Existing CCGT Fleet	Existing CT Fleet	New Flexible CCGT
Maximum output (MW/unit)	375	57	500
Minimum stable level (% of maximum output)	51%	41%	30%
Maximum ramp rate (% of Pmax per min)	0.9%	4.9%	1.7%
Minimum up time (hrs)	8.0	3.1	1
Minimum down time (hrs)	4.5	2.4	1
Heat rate at Pmin (kBtu/MWh)	8,117	13,152	8,000
Heat rate at Pmax (kBtu/MWh)	7,374	10,248	7,000

Study Findings. The Flexibility Assessment modeled a gas flexibility case that added 6,000 MW of new flexible combustion turbines to the existing fleet. The modeling results showed that the addition these new flexible combined cycles did not lower the amount of curtailed renewable energy in any region. See Figure 15.

Figure 15.

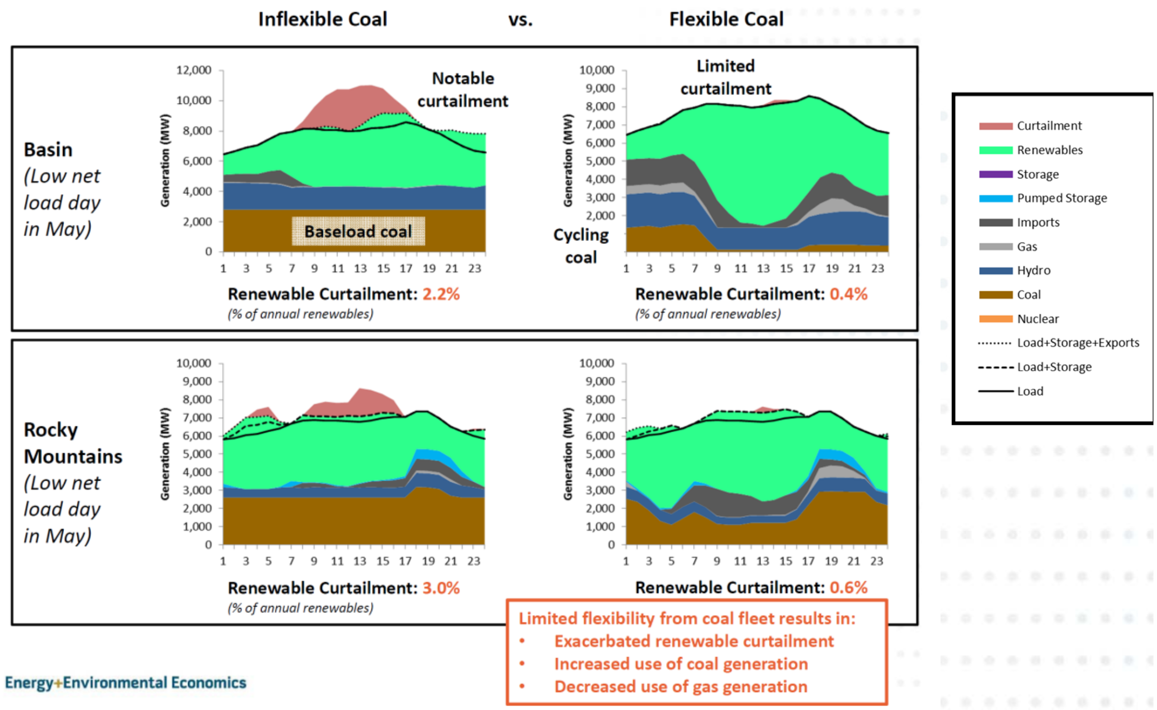
In California and the Southwest region, these flexible combined cycles were used on the shoulder periods (morning and evening) of the large mid-day solar peak. The flexible combined cycle units were not operating during the period of surplus generation, and therefore did not contribute to lowering the amount of curtailment in the solar-dominated regions. In the Northwest, the flexible combined cycle units had lower average capacity factors across the year. The period of operation tended to be during the evening hours with marginally more seasonal use in July and December. It may be that the hydro system serves as a relatively cheaper source of flexibility than the flexible combined cycle units.

The flexibility of the coal fleet is another critical factor influencing the ability of the power system to integrate renewable generation. As noted above, coal plants have historically been operated as baseload units with little need for flexibility. In regions with a large coal fleet, finding new flexibility in coal operations can make a big difference in whether increasing levels of renewables can be integrated into the power system.

Key constraints determining coal plant flexibility are the minimum generation level, the start-up time, and ramp rates. Models attempt to represent these constraints in simulating actual market operations. In the Flexibility Assessment study, the probabilistic modeling technique compiled data in three-day periods. As a result, the constraints representing minimum up time and minimum down time are not enforced. This leads to a higher degree of flexibility for coal plants than what actual operations encounter. The Flexibility Assessment study modeled an additional sensitivity case that imposed a high penalty cost ($1 billion/MWh) on coal unit startup and shutdowns to discourage potentially excessive coal plant cycling.

Figure 16 below presents the results for the Basin and the Rocky Mountains with a side-by-side comparison of the flexible coal case and the inflexible coal case for a day in May. For the Basin, the inflexible coal case increased curtailment from 0.4% to 2.2% of renewable generation. Similar for the Rocky Mountain region, the inflexible coal case raised curtailment from 0.6% to 3.0% in the inflexible case.

Figure 16.



The important insight from these results has less to do with the magnitude of curtailment than the direction of curtailment reduction. Steps that enable coal plants to be more flexible will make it easier to integrate more renewable energy.

Creating a flexible thermal fleet provides the physical capability for a more flexible power system. However, tapping into the physical flexibility is only possible if the power system has an efficient institutional operating system. Institutional constraints on operations nullify gains in physical system flexibility. Section 4.1 above addressed the potential benefits of regional coordination to enhance system flexibility.

The Low Carbon Grid Study performed sensitivity analyses and identified two institutional constraints that have a very large impact on renewable curtailment. The first institutional constraint was an import requirement for California's generation resources that located in another state. The important constraint required that 70% of output from these out-of-state resources must be physically delivered into California for every hour. Another institutional constraint required that California loads must be served at all times by 25% local gas generation. Both of these constraints were modeled as part of conventional grid assumptions that followed CAISO modeling practices at the time. Removing these institutional constraints contributed to a significant reduction of renewable curtailment for both a diversified renewable portfolio (Target Case curtailment dropped from 4.2 % to 0.2%) and a high solar renewable mix (High Solar Case curtailment declined from 9.7% to 0.5%).[22] The important point is that physical system flexibility must have complementary institutional operating system that does not constrain power system flexibility.

Application. Xcel Energy of Colorado has taken a series of steps to make its thermal fleet more flexible in order to integrate high levels of wind generation into its operations. In 2010, Xcel Energy modified a 750 MW combined cycle unit that lowered its minimum generation level by 300 MW and squeezed the time needed between shut-off and restart from 8 hours to 2 hours. In 2011, it lowered the minimum operating level of a large coal unit from 500 MW to 405 MW. In addition to these operational improvements, Xcel is carrying out a series of coal plant retirements and other unit conversions to natural gas pursuant to Colorado's Clean Air Clean Jobs policy. These steps along with others made it possible for Xcel Colorado to integrate high levels of wind energy on its system.[23]

5. Conclusion

Variable energy resources, particularly wind and solar energy, are becoming an increasing and significant source of clean electric generation in the Western Interconnection. Western states have been a key driver behind the growth of renewables through renewable portfolio standard policies. Future economic drivers and public policies may increase the level of renewable generation in the electric sector even more. An important threshold technical question is whether the power system has sufficient flexibility to reliably integrate higher penetration levels of variable energy resources.

A growing body of research is providing new insights on the challenges of integrating high levels of variable renewable generation on the grid. Collectively, this research provides promising steps to improve power system flexibility to integrate higher levels of renewable energy.

5.1. Key Findings

Improved regional coordination provides greater power system flexibility. Higher levels of renewable energy can be incorporated into the power system if the 38 BAs and regions within the Western Interconnection can more easily export surplus generation or import cheaper power

[22] National Renewable Energy Laboratory, Low Carbon Grid Study: Analysis of 50% Emission Reduction in California, 2016, at pages ES vii, 22-23, and 38-40.
[23] Weiss, Jurgen, and Bruce Tsuchida, "Integrating Renewable Energy into the Electricity Grid: Case Studies showing how system operators are maintaining reliability," The Brattle Group, 2015. http://info.aee.net/hubfs/EPA/AEEI-Renewables-Grid-Integration-Case-Studies.pdf?t=1444082753239

to and from other jurisdictions, rather than each operating as a separate island. Fluctuations in renewable energy can be integrated more easily in larger systems with higher load levels.

Diversification of the renewable generation fleet improves power system flexibility with different renewable technologies and the geographic locations of generators. Technological diversity within the renewable generation fleet helps smooth out daily and seasonal variations that can occur among sources of wind, solar, geothermal, and biomass generation. Geographic diversity also helps spread out variation in renewable generation resulting from changing weather conditions, solar intensity, and daylight hours.

Energy storage provides additional power system flexibility by allowing system operators to separate the time of generation from the time of dispatch. Current storage resource technologies include traditional pump storage, battery storage, and compressed air energy storage systems.

Advanced demand response resources contribute to the ability of the power system to ramp up and ramp down. A future large fleet of electric vehicles could augment the size of demand response resources if strategically coordinated with the power grid.

Improving flexibility of the thermal fleet contributes the ability of the power system to integrate variable generation. Key factors influencing the flexibility of the thermal fleet are minimum down times between shut down and start up, minimum stable generation level, and ramp rates up and ramp rates down.

5.2. Options for Moving Forward

Given the challenges surrounding the integration of high levels of variable renewable generation into the grid, policy makers could consider the following options:

Option 1: Identify opportunities to improve power system flexibility. Public utility commissions could request that utilities within their jurisdiction perform flexibility assessments in their integrated resource planning process to identify options to make the power system more flexible, while meeting foreseeable higher levels of renewable generation.

State energy offices and public utility commissions within a region could propose and sponsor regional level flexibility assessments that would identify foreseeable future renewable generation levels and identify options to improve power system flexibility through better coordination among Balancing Authorities, resource procurement, transmission expansion, and market enhancements.

Option 2: Engage in regional coordination of a larger energy market. Public utility commissions could ask utilities within their jurisdiction to perform a benefit cost assessment study of participating in the EIM.

State energy offices and public utility commissions could support the development and formation of larger and more efficient energy markets that include real time markets, day-ahead markets, and an independent system operator. Potential options to improve markets include the expansion of the California ISO or potentially the new Mountain West Transmission Group.

Public utility commissions could encourage utilities within their jurisdiction to investigate operational technology improvements that enhance the ability of potential buyers and sellers to trade power over the grid.

Option 3: Promote diversification of the renewable mix. Public utility commissions could ask utilities within their jurisdiction to use their integrated resource planning processes to investigate the benefits of renewable resource diversity. Different renewable technologies and regionally diverse resources can reduce daily or seasonal imbalances.

State energy offices could collaborate to promote and enhance energy trading between high quality wind region and high quality solar regions.

Option 4: Evaluate and implement promising storage technologies. Public utility commissions could encourage utilities within their jurisdiction to use their integrated resource planning processes to consider whether energy storage would reduce daily or seasonal imbalances in an efficient manner.

State energy offices could establish pilot programs that provide utilities with incentives for implementing promising storage technologies.

Option 5: Evaluate and provide incentives for advanced demand response. Public utility commissions could encourage utilities within their jurisdiction to use their integrated resource planning processes to investigate the potential for demand response resources in their respective area and to evaluate the potential contributions of Demand Response (DR) resources to enhancing system flexibility.

State energy offices could establish pilot programs that link utilities to recharging systems for EVs and investigate incentives to better align recharging practices with demand response programs.

Option 6: Improve flexibility of the thermal generation fleet. Public utility commissions could encourage utilities within their jurisdiction to use their integrated resource planning processes to evaluate whether utilities in their jurisdiction could improve thermal fleet flexibility through:

a. Modifying the existing gas units to improve ramp rates, minimum down times between starts, and minimum operating stable levels;
b. Adding new more flexible gas units when additional capacity is needed;
c. Modifying the existing coal units to improve ramp rates, minimum down times between starts, and minimum operating stable levels.

References

Energy and Environmental Economics (2014), Investigating a Higher Renewables Portfolio Standard in California, San Francisco, CA: Energy and Environmental Economics. https://ethree.com/documents/E3_Final_RPS_Report_2014_01_06_with_appendices.pdf.

Energy and Environmental Economics (2015), Western Interconnection Flexibility Assessment, San Francisco, CA: Energy and Environmental Economics. https://www.wecc.biz/Reliability/WECC_Flexibility_Assessment_Report_2016-01-11.pdf.

GE Energy (2010). Western Wind and Solar Integration Study Phase 1, National Renewable Energy Laboratory/SR-550-47434. Golden, CO: National Renewable Energy Laboratory. http://www.nrel.gov/docs/fy10osti/47434.pdf.

GE Energy (2014). Western Wind and Solar Integration Study Phase 3, National Renewable Energy Laboratory/SR-5D00-62906. http://www.nrel.gov/docs/fy15osti/62906.pdf .

National Renewable Energy Laboratory (2013). Western Wind and Solar Integration Study Phase 2, National Renewable Energy Laboratory/SR-5500-55888, Sept. 2013. http://www.nrel.gov/docs/fy13osti/55588.pdf.