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RENEWABLE, RELIABLE, RESILIENT

Policy Approaches for Maintaining Reliability in the Western Grid Under the Clean Power Plan

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OCTOBER 2015

Acknowledgments

This report was made possible through support from the Oregon Community Foundation and in-kind support from Lewis & Clark Law School. The opinions and recommendations expressed in this report are those of the author and do not necessarily reflect the views of our sponsor or Lewis & Clark Law School.

The author would like to extend her appreciation to Melissa Powers for her guidance, insight, and editorial contributions to this report. The author also wishes to express her gratitude to Henry Tilghman and Jonathan Norling for their thorough and insightful reviews of this report. The author would like to thank Associate Dean Janice Weis and Assistant Director Lucy Brehm of Lewis & Clark Law School's Environmental, Natural Resources, and Energy Law Program for their support and guidance.

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The **Green Energy Institute** is a renewable energy policy organization within Lewis & Clark Law School's Environmental, Natural Resources, and Energy Law Program. The Green Energy Institute develops strategies and advocates for a transition to a renewable energy grid.

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TABLE OF CONTENTS

EXECUTIVE SUMMARY

The U.S. Environmental Protection Agency's Clean Power Plan establishes an innovative approach to regulating emissions from existing fossil fuel-fired power plants. The final rule encourages states to implement an array of available measures to directly and indirectly reduce carbon dioxide emissions from existing coal plants. In addition to directly controlling emissions from affected generating facilities, the Clean Power Plan's flexible approach gives states the option to reduce emissions by deploying lower- or non-emitting resources, such as renewable energy, or increasing demand-side energy efficiency. By allowing states to implement both onsite and offsite emissions reductions measures, the rule gives states flexibility to select the most cost-effective strategies for reducing power sector emissions. However, this flexible approach has also incited concerns among some stakeholders that individual compliance strategies could compromise the reliability of the power grid. While the shift from fossil fuel-fired generation to variable renewable resources will present some reliability-related challenges, the Clean Power Plan also presents an unprecedented opportunity for western states to modernize the grid and transition to a more sustainable, resilient electricity system.

The Clean Power Plan establishes source category-specific emission performance rates and state-specific rate-based and mass-based goals for reducing carbon emissions from existing power plants 32 percent below 2005 levels by 2030. The rule establishes an emission performance rate of 1,305 pounds of carbon dioxide (CO_2) per megawatt-hour (MWh) of generation for fossil fuel-fired electric steam generating units, and a performance rate of 771 pounds of CO_2 per MWh (lbs. CO_2/MWh) for stationary combustion turbines. States have the option to apply these rates as federally enforceable emission standards for the affected electric generating units (EGUs) within their respective jurisdictions.

The Clean Power Plan also includes state-specific rate-based and mass-based CO_2 emission goals that states may apply as an alternative to the source-specific performance rates. The state-specific rate-based goals represent the weighted

TABLE EX. 1

STATEWIDE RATE-BASED EMISSION PERFORMANCE GOALS (lbs. CO_2/MWh)

STATE	INTERIM STEP 1 2022–2024	INTERIM STEP 2 2025–2027	INTERIM STEP 3 2028–2029	INTERIM GOAL 2029	FINAL GOAL 2030
ARIZONA	1,244	1,133	1,060	1,157	**1,018**
CALIFORNIA	961	890	848	907	**828**
COLORADO	1,476	1,332	1,233	1,362	**1,174**
IDAHO	877	817	784	784	**832**
MONTANA	1,671	1,500	1,380	1,534	**1,305**
NEVADA	1,001	924	877	942	**855**
NEW MEXICO	1,435	1,297	1,203	1,325	**1,146**
OREGON	1,026	945	896	964	**871**
UTAH	1,483	1,339	1,239	1,368	**1,179**
WASHINGTON	1,192	1,088	1,021	1,111	**983**
WYOMING	1,662	1,492	1,373	1,526	**1,299**

Data from Clean Power Plan Table 12

TABLE EX. 2

STATEWIDE MASS-BASED EMISSION PERFORMANCE GOALS (short tons CO_2)

STATE	INTERIM STEP 1 2022–2024	INTERIM STEP 2 2025–2027	INTERIM STEP 3 2028–2029	INTERIM GOAL 2029	FINAL GOAL 2030
ARIZONA	35,189,232	32,371,942	30,906,226	33,061,997	**30,170,750**
CALIFORNIA	53,500,107	50,080,840	48,736,877	51,027,075	**48,410,120**
COLORADO	35,785,322	32,654,483	30,891,824	33,387,883	**29,900,397**
IDAHO	1,615,518	1,522,826	1,493,052	1,550,142	**1,492,856**
MONTANA	13,776,601	12,500,563	11,749,574	12,791,330	**11,303,107**
NEVADA	15,076,534	14,072,636	13,652,612	14,344,092	**13,523,584**
NEW MEXICO	14,789,981	13,514,670	12,805,266	13,815,561	**12,412,602**
OREGON	9,097,720	8,477,658	8,209,589	8,643,164	**8,118,654**
UTAH	28,479,805	25,981,970	24,572,858	26,566,380	**23,778,193**
WASHINGTON	12,395,697	11,441,137	10,963,576	11,679,707	**10,739,172**
WYOMING	38,528,498	34,967,826	32,875,725	35,780,052	**31,634,412**

Data from Clean Power Plan Table 13

aggregate of the emission performance rates as applied to each state's affected EGUs. For example, if a state only contains electric steam generating units, its rate-based goal would be 1,305 lbs. CO_2/MWh. The mass-based goals represent the total CO_2 emissions each state may emit during the rule's compliance periods. In the western United States, the rule's rate-based goals range from 771 lbs. CO_2/MWh in Idaho to 1,305 lbs. CO_2/MWh in Montana. The rule's mass-based goals range from 8,118,654 tons of CO_2 in Oregon to 48,410,120 tons of CO_2 in California.

The Clean Power Plan's emission performance rates and aggregated emission goals represent the level of emissions reductions that EPA determined states can achieve through application of the "best system of emissions reductions" that has been "adequately demonstrated." This system is known as the BSER. EPA determined that the BSER for reducing CO_2 emissions from existing power plants includes a series of three control strategies or "building blocks." These BSER building blocks include increasing coal plant heat rate efficiencies, replacing coal power with natural gas, and deploying zero-emitting renewable energy generation.

The Clean Power Plan gives states discretion to implement any or all of the BSER strategies to reduce power-sector emissions. The rule also provides states with flexibility to implement additional strategies and measures to avoid power-sector emissions through reduced electricity consumption due to demand-side management and energy efficiency. States can choose to follow an emission standards approach that applies federally enforceable emission standards directly to the states' affected EGUs, or states can follow a state measures approach that incorporates both on-site standards and off-site emission reduction strategies. States can also participate in interstate emission trading with other states following the same type of implementation approach.

The Clean Power Plan gives states significant flexibility to implement the most cost-effective emission reductions strategies available. However, this flexibility also creates some uncertainty as to how state compliance efforts will impact the power grid as a whole. The electricity needs for the western United States are served through a single power grid called the western interconnection. Eleven western states are fully integrated into this grid: Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming. Due to the interconnected nature of the western grid, Clean Power Plan compliance activities in one state could impact electric system reliability in multiple other states. Regulatory entities must therefore coordinate and cooperate with one another to ensure that state compliance activities do not compromise the functionality and reliability of the western grid as a whole.

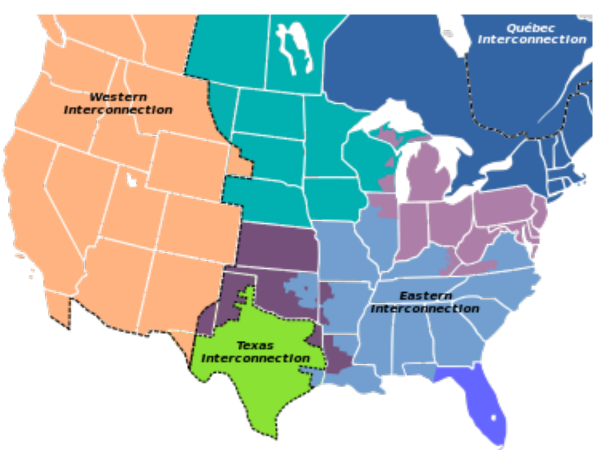
The western interconnection is governed by a complex jurisdictional framework under which local, state, and federal governments share regulatory authority. The Federal Energy Regulatory Commission, or FERC, generally has jurisdiction over the transmission of electricity over the western grid. The North American Reliability Corporation (NERC) is the FERC-appointed Electric Reliability Organization for the entire North American transmission system. The Western Electricity Coordinating Council, or WECC, is the FERC-approved regional reliability entity for the western grid. Together, these entities work to maintain the reliability of the power grid.

The western interconnection is subdivided into 38 balancing areas that include all power generation, transmission, and consumption within a defined geographic area. These balancing areas are managed by grid operators called balancing authorities, which are responsible for balancing power generation and demand (load) across their respective territories on a continuous basis. In the western United States, balancing authorities include investor-owned utilities, consumer-owned utilities, independent power companies, and federal power marketing administrations.

These entities fall under the jurisdiction of various state and federal regulatory agencies. While FERC has jurisdiction over the interstate transmission system, states have jurisdiction over the local distribution or retail sale of electricity to end-users. State Public Utility Commissions (PUCs) generally have jurisdiction over investor-owned utilities, while local elected officials or consumer-members generally have jurisdiction over consumer-owned utilities. Federal power marketing agencies are generally not under state regulatory jurisdiction.

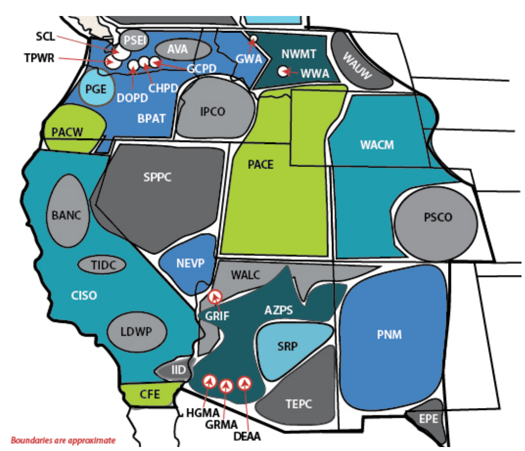
This complex jurisdictional dynamic introduces additional complexity into implementing the Clean Power Plan in the west. Because balancing authorities may fall under the jurisdiction of local, state, or federal electricity regulators, states must ensure that applicable regulatory requirements will not conflict with state compliance efforts or compromise the reliability of the power grid. Moreover, state utility regulators must collaborate closely with state environmental and air quality agencies to craft implementation plans that will enable each state to meet the Clean

NORTH AMERICAN INTERCONNECTIONS



NERC; Bouchecl © 2009

WESTERN BALANCING AREAS



Western Electricity Coordinating Council (2013)

Power Plan's emission reductions while maintaining the reliability and functionality of the regional grid.

The Clean Power Plan has the potential to significantly alter the composition of the energy mix in the western United States. Coal currently plays a significant role in the western electricity sector, particularly in the intermountain west. Because coal-fired power plants emit substantially more carbon dioxide than other generating resources, some western states will need to retire some or all of their coal-fired generation to comply with the Clean Power Plan. States are expected to replace this coal capacity with a mix of natural gas, renewable energy, and energy efficiency. While the WECC predicts that western states will primarily replace coal-fired capacity with natural gas combined cycle units, the final rule restricts states from replacing existing coal-fired capacity with substantial new natural gas-fired capacity. Furthermore, pipeline constraints and fuel price volatility could persuade regulators and utilities that renewable resources and energy efficiency are more cost-effective options over the long term.

Western states are already expected to deploy significant renewable energy capacity over coming decades, and the Clean Power Plan will likely give rise to additional investments in these resources. Renewable energy resources, such as wind and solar power, will likely provide a cost-effective means of reducing emissions in many states. A number of western states have adopted Renewable Portfolio Standards (RPSs) that require renewable energy to provide a specified percentage of retail electricity sales, and these standards have spurred renewable energy development throughout the region. However, the rule only allows states to credit emission reductions resulting from incremental renewable energy capacity installed after 2012, because existing renewable capacity is already reflected in states' 2012 baselines. The Clean Power Plan will thus encourage western states with and without RPSs to deploy additional renewable resources to achieve their emissions reduction goals. In addition, the rule includes a Clean Energy Incentive Program that rewards states for early deployment of renewables.

The western United States has tremendous potential to produce electricity from renewable resources. While the shift to a renewably powered grid will produce significant long-term benefits for the region, the anticipated transition from coal-fired generation to renewable power will create some challenges for the western grid. Grid operators must continuously balance load *(i.e.* energy demand) and supply (*i.e.* energy generation) within the system to maintain the reliability of the power grid. Baseload generating resources, such as coal-fired power plants, support grid reliability by providing power when demand is high and reducing output when demand is low. Variable renewable resources, such as wind or solar power, generally cannot adjust output to reflect shifts in supply or demand. Replacing baseload capacity with variable renewable capacity presents additional challenges for maintaining grid reliability.

The final Clean Power Plan includes a series of provisions designed to protect the reliability of the grid system. States are required to consider reliability during the plan development stage, and the rule includes two mechanisms that enable states to revise their implementation plans to respond to unforeseen reliability issues or allow reliability-critical EGUs to temporarily comply with modified emission standards during emergency events. While these provisions provide states with additional flexibility to respond to reliability constraints, the rule's reliability safeguards alone will not prevent reliability issues from arising as the region works to implement the Clean Power Plan. Western states should strive to mitigate many of the constraints associated with integrating variable renewable energy by undertaking a coordinated effort to modernize the grid and increase flexibility and reliability across the system.

Strategies to Promote Grid Reliability

A number of operational practices and available technologies can assist grid operators in integrating high levels of renewable energy onto the grid. First, policymakers can optimize operations of the existing grid to balance variable loads and maximize transmission capacity. Second, policymakers can incentivize or require deployment of advanced technologies to stabilize variable loads, reduce grid congestion, and maximize existing transmission capacity. Third, policymakers can explore cooperative and market-based approaches to increase the efficiency and flexibility of the existing grid. While optimizing the grid to integrate significant new variable renewable power capacity will likely require additional transmission development, this report primarily focuses on strategies to modernize and optimize existing grid infrastructure.

I. OPTIMIZE GRID OPERATIONS

To reliably integrate variable renewable capacity onto the grid without compromising reliability, policymakers can encourage grid operators to optimize operations and practices within the existing system.

- **PROMOTE DEVELOPMENT OF GEOGRAPHICALLY DIVERSE RENEWABLE RESOURCES.** When a balancing area contains substantial solar or wind capacity within a confined geographic area, localized weather conditions can significantly impact the output from these variable renewable resources. Sudden increases or decreases in output can contribute to imbalances on the system and compromise grid reliability. Policymakers can mitigate the reliability constraints associated with variable weather conditions by promoting development of geographically diverse resources with varying hourly profiles.
- **IMPROVE WIND AND SOLAR FORECASTING.** Wind availability can vary significantly on an hourly or daily basis, and grid operators must make rapid adjustments to accommodate sudden fluctuations in wind output and prevent congestion on the transmission system. Similarly, passing cloud cover can cause sudden drops in solar power output. By implementing improved weather forecasting, grid operators can better predict and plan for variable renewable output over shorter periods of time. Modern forecasting tools enable grid operators to reduce operating reserves, prepare for extreme weather conditions, and cost-effectively integrate variable renewable energy onto the grid.
- **IMPLEMENT SUB-HOURLY TRANSMISSION SCHEDULING AND ENCOURAGE SALES OF SUB-MEGAWATT TRANSMISSION SERVICES.** To sell output over the bulk transmission system, independent power

> STRATEGIES TO OPTIMIZE GRID OPERATIONS
>
> 1. Promote geographical diversity
> 2. Improve forecasting
> 3. Offer sub-hourly, sub-megawatt transmission scheduling and service
> 4. Enable dynamic transfers
> 5. Improve reserve sharing
> 6. Orient solar panels to stabilize daily output

producers must purchase and schedule transmission services in advance. Renewable power producers must generally purchase transmission service in one-hour increments for megawatt-hour blocks of capacity, which places variable renewable power generators at a disadvantage. These requirements can also negatively impact grid reliability if producers are unable to deliver their pre-scheduled output on an hour-to-hour basis or their output exceeds the generator's purchased transmission capacity. To mitigate these constraints, regulators must ensure that renewable power producers have access to sub-hourly transmission services and should require distribution utilities to accept renewable power deliveries that exceed pre-scheduled megawatt hour increments.

- **ENABLE DYNAMIC TRANSFERS OF VARIABLE GENERATION BETWEEN BALANCING AREAS.** Dynamic transfers enable grid operators to correct imbalances in power supply or demand on the system by transferring power between different balancing areas on a sub-hourly basis. These transfers can help grid operators integrate variable renewable output by enabling a balancing area with excess wind or solar output to transfer power to a balancing area that has available transmission capacity. This allows balancing areas to exchange and balance variable output over a larger geographic area.
- **IMPROVE RESERVE SHARING OVER LARGER GEOGRAPHIC AREAS.** Balancing authorities help maintain reliability on the system by deploying generation reserves or curtailing load as needed to balance power supply and demand or respond to unanticipated events. As variable renewable capacity increases across the west, grid operators will need access to sufficient reserves to respond to fluctuations in renewable output. To reduce the need for one balancing area to invest in additional generation reserves to meet peak demand, balancing authorities can participate in reserve sharing groups that enable participants to share and deploy balancing and contingency reserves to respond to fluctuations in renewable output.
- **ORIENT SOLAR PANELS TO STABILIZE OUTPUT OVER LONGER PERIODS OF THE DAY.** Most solar power systems face the south, which maximizes power production over the course of the day. However, the output from a south-facing system may not coincide with consumer energy demands, which generally peak in the late afternoon or evening. As solar power penetrations increase across the west, south-facing installations may cumulatively impose additional pressure on the grid. As solar output decreases and load increases, grid operators must quickly dispatch peaking generating units to satisfy evening energy demand. To help alleviate this pressure on the grid, policymakers can encourage solar power producers to orient panels towards the west in addition to the south. West-facing solar installations produce less power on an annual basis, but produce more power between the hours of 3:00 and 7:00 p.m. The output from west-facing systems thus can enable solar power to meet a greater percentage of peak demand, which in turn can reduce the need for additional peaking capacity and alleviate some of the reliability constraints presented by waning solar output.

II. DEPLOY ADVANCED TECHNOLOGIES

To maintain reliability while integrating high levels of variable renewable energy onto the western grid, policymakers can incentivize or require deployment of advanced technologies that help stabilize variable loads, reduce grid congestion, and maximize existing transmission capacity.

- **NON-VARIABLE RENEWABLE ENERGY GENERATION.** States can help grid operators maintain reliability under the Clean Power Plan by encouraging power producers to deploy non-variable renewable resources in addition to variable renewables. Some renewable resources, such as biogas, geothermal, and small-scale hydroelectric facilities, have the potential to provide predictable, stable generating outputs. These less- or non-variable resources help support grid reliability by minimizing unintentional fluctuations in generation.
- **ENERGY STORAGE.** Energy storage can mitigate the reliability constraints associated with variable renewable power outputs by enabling grid operators to dispatch renewable power during peak demand periods. When variable renewable output exceeds power demands on the grid, this output is "stored" in an energy storage device, such as a pumped hydro facility, flywheel, compressed air system, or rechargeable battery, and then dispatched onto the grid when demand increases. Utility-scale energy storage systems, such as large capacity pumped hydro facilities, can assist grid operators in maintaining balance on the system and reduce the need for new transmission capacity. Distributed storage systems, such as small-scale battery arrays, can enable users to consume renewable power on demand and help alleviate congestion on local distribution systems.
- **SMART GRID AND INFORMATION TECHNOLOGIES TO FACILITATE DEMAND RESPONSE.** Demand response programs encourage consumers to reduce their power consumption during peak demand periods. Demand response technologies can support grid reliability by allowing grid operators to flexibly balance supply and demand across the system with reduced reliance on peaking generating units. Smart grid technologies, such as advanced electricity meters and smart thermostats, promote demand response by providing consumers with real-time electricity rate and usage data, or allowing utilities to control or adjust customer electricity consumption from some devices or appliances during periods of high demand.

DEPLOY ADVANCED TECHNOLOGIES

7. Non-variable renewable energy generation
8. Energy storage
9. Smart grid and information technologies

III. EXPLORE COOPERATIVE AND MARKET-BASED APPROACHES

To further support grid reliability under the Clean Power Plan, policymakers can explore cooperative and market-based approaches to help the existing grid operate more efficiently by providing real-time access to unused transmission capacity across the region. Regional cooperation among western states may support grid reliability by enabling states to develop individual implementation strategies that harmonize with broader regional compliance strategies.

COOPERATIVE AND MARKET-BASED APPROACHES

1. Regional emission trading program
2. Energy Imbalance Market
3. Multi-State Clean Power Plan Coordination

- **REGIONAL EMISSION TRADING PROGRAM.** An interconnection-wide emission trading market for emission reduction credits or allowances would allow states to implement cost-effective compliance strategies on a regional basis. A market-based trading program would support grid reliability by providing affected EGUs with flexible, geographically diverse compliance options. A trading program would also incentivize cost-effective renewable energy development across the west.
- **ENERGY IMBALANCE MARKET.** To support the grid integration of additional variable renewable energy capacity under the Clean Power Plan, western states should evaluate the strengths and weaknesses of participating in an interconnection-wide energy imbalance market (EIM). An EIM is a sub-hourly energy marketplace that allows generators and transmission owners to sell power and capacity in short-term intervals to balance power and load on the grid. A regional EIM could allow grid operators to more efficiently manage congestion or power shortfalls across multiple balancing areas. In doing so, an EIM could help mitigate transmission capacity constraints across the region and thus reduce the need for additional infrastructure. However, an EIM could also impose new costs and complexities onto the existing system, and would require significant cooperation between participants to reduce opportunities for market manipulation or abuse. Policymakers and potential participants should therefore assess the potential risks and benefits of a regional EIM to determine whether this type of market represents an optimal approach for the west.
- **MULTI-STATE CLEAN POWER PLAN COORDINATION.** Western states can support grid reliability by coordinating their compliance strategies and participating in a multi-state assessment of state implementation plans. Regional coordination should support interconnection-wide reliability by ensuring that individual state implementation plans complement, rather than conflict with, state and multi-state compliance strategies across the west.

Policy Recommendations to Support Grid Reliability Under the Clean Power Plan

To effectively implement the strategies discussed above, state and federal decision makers will likely need to adopt policies that incentivize or require the power sector to adjust existing practices and invest in infrastructure upgrades that make the grid more flexible and reliable. Policymakers can adopt a variety of laws and regulations to implement these grid reliability strategies, which are explored in greater detail in Part VI. The following list outlines some general policy recommendations to support grid reliability under the Clean Power Plan.

- Federal, state, and local land use authorities should adopt coordinated siting, permitting, and approval processes that promote renewable energy development in optimal locations throughout the western region and facilitate development of transmission infrastructure to connect these areas to load centers.
- Policymakers should provide technical and financial support for the development and installation of advanced forecast models and modeling equipment.
- State and federal regulators should clarify that transmission providers must offer transmission services in sub-hourly intervals and encourage sales of transmission capacity in sub-megawatt-hour increments.
- Policymakers should offer economic incentives for grid upgrades and smart grid technologies that provide reliability benefits for states and the region.
- Regulators should encourage balancing authorities to participate in balancing and contingency sharing reserve groups that permit reserve sharing in response to imbalances resulting from changing weather conditions.
- State policymakers should adopt economic incentives or procurement mandates to support the development of variable and non-variable renewable energy and energy storage systems.
- Policymakers should evaluate the strengths and weaknesses and potential grid reliability benefits of a regional emission trading program, an energy imbalance market, and other cooperative Clean Power Plan compliance strategies.

Implementing the Clean Power Plan may present new challenges for maintaining reliability in the western grid, yet the rule also provides an opportunity to modernize and optimize the grid to facilitate the transition to a more sustainable energy system. Western states can effectively integrate high levels of renewable energy without compromising reliability by optimizing grid operations, deploying advanced technologies, and implementing cooperative and market-based mechanisms to facilitate efficient regional compliance with the proposed rule. To ensure that individual state compliance strategies support the reliability of the interconnected grid system, states should work together to preemptively address inevitable changes in the western resource mix. In doing so, western states should strategically invest in resources, technologies, and operational practices that strengthen the grid as a whole and support the transition to a clean, renewable energy sector.

I. INTRODUCTION

The U.S. Environmental Protection Agency's Clean Power Plan establishes an innovative approach to regulating power-sector emissions that allows states to implement a variety of strategies to reduce carbon dioxide (CO_2) emissions from existing power plants. In addition to directly controlling emissions from affected electric generating units, the rule's flexible approach gives states the option to reduce emissions through deployment of lower- or non-emitting resources, such as renewable energy, or through reductions in electricity use due to increased demand-side energy efficiency. The Agency designed the rule to give states the flexibility and discretion to develop cost-effective strategies for reducing carbon emissions. This flexible approach initially sparked concerns that individual state compliance strategies could compromise the reliability of the power grid. In response to these concerns, the final rule requires states to consider grid reliability as they develop their plans to implement the rule.

In the west, Clean Power Plan compliance will entail replacing significant coal-fired capacity with a combination of natural gas, renewable energy, and demand-side energy efficiency. This transition will lead to increased deployment of renewable energy resources (primarily wind and solar power) across the region. Increased generation from variable renewable energy sources will introduce new challenges for western grid operators responsible for maintaining reliability across the system. However, these challenges also create opportunities for western states to modernize the power grid and facilitate the transition to a clean, sustainable electricity system. This report explores the potential challenges presented by the Clean Power Plan, and discusses strategies to mitigate grid reliability constraints and modernize the existing grid.

This report introduces a variety of strategies that policymakers and grid operators can implement to integrate variable renewable generation without compromising grid reliability. Part VI provides a suite of policy recommendations designed to modernize grid operations and maximize available capacity in the existing transmission system. While optimizing the western grid to effectively integrate large quantities of variable renewable power will likely require substantial investments in new transmission infrastructure, this report focuses on strategies that make the most use of existing transmission lines.

Part II provides a brief overview of the final Clean Power Plan. Part III describes the complex regulatory and jurisdictional frameworks that govern the transmission of electricity over the western grid. Part IV discusses the rule's implementation in the western United States and considers how the rule may affect the composition of the region's energy mix. Part V explores how the shift from coal power to renewable energy may impact the reliability of the western grid. Part VI introduces strategies to maintain reliability while integrating additional renewable energy capacity onto the grid, and recommends policy approaches to optimize the functionality and flexibility of the existing grid under the Clean Power Plan. This report concludes that western states can successfully implement the Clean Power Plan without compromising the long-term reliability of the power grid.

II. THE CLEAN POWER PLAN

On August 3, 2015, the U.S. Environmental Protection Agency (EPA) issued a final rule to regulate CO_2 emissions from existing power plants under section 111(d) of the Clean Air Act.[1] This rule, which the Agency informally named the Clean Power Plan, directs states to reduce CO_2 emissions through a combination of measures that directly or indirectly limit emissions from existing fossil fuel-fired power plants. EPA projects that the rule will reduce national CO_2 emissions 32% below 2005 levels by 2030.[2]

Section 111 of the Clean Air Act directs EPA to regulate emissions from listed categories of stationary sources of air pollutants that may endanger public health or welfare. Under section 111(b), EPA must list categories of sources that the Agency determines either cause or contribute to "air pollution which may reasonably be anticipated to endanger public health or welfare."[3] EPA must then promulgate standards of performance for new sources within that listed source category.[4] Once EPA issues these standards for new sources, section 111(d) directs the Agency to establish a procedure for states to follow in developing a plan to control emissions from existing sources within the listed source category.[5] These state plans must establish standards of performance for controlling emissions from the existing sources. The federal 111(d) implementing regulations direct EPA to publish emission guidelines that reflects the degree of emission reduction achievable through application of the best system of emission reduction that has been adequately demonstrated for the affected sources.[6] A state's standards of performance cannot be less stringent than EPA's emission guidelines.[7]

In 2009, EPA issued an endangerment finding concluding that greenhouse gases "may reasonably be anticipated both to endanger public health and to endanger public welfare."[8] In January 2014, the Agency proposed standards of performance for CO_2 emissions from new electric generating units under section 111(b) of the Clean Air Act.[9] Six months later, EPA issued a draft rule to regulate CO_2 emissions from existing electric generating units under section 111(d) of the Clean Air Act.[10] On August 3, 2015, the Agency concurrently issued final new source performance standards and the Clean Power Plan.[11]

The Clean Power Plan establishes CO_2 emission guidelines for existing fossil fuel-fired electric generating units (EGUs).[12] These emission guidelines give states considerable flexibility and discretion in determining how to implement the rule's regulatory directives. The rule establishes federally enforceable emission performance rates for the two subcategories of EGUs subject to the rule. Fossil fuel-fired electric steam generating units must meet a final emissions rate of 1,305 pounds of CO_2 per megawatt-hour of generation (lbs. CO_2/MWh), and stationary combustion turbines must meet a final rate of 771 lbs. CO_2/MWh.[13]

These emission performance rates reflect the emission reductions that are achievable through application of the "best system of emissions reduction" that EPA determined has been "adequately demonstrated" for these sources.[14] EPA determined that the "best system of emissions reductions," or

BSER, for fossil fuel-fired EGUs is comprised of three "building blocks," which include 1) improving the heat rates at affected coal-fired EGUs, 2) substituting generation from natural gas combined cycle units for generation from higher-emitting steam EGUs; and 3) substituting generation from zero-emitting renewable energy for generation from fossil fuel-fired EGUs.[15] EPA determined that these emission reduction strategies are available to all affected EGUs. However, states are neither required nor expected to apply these control strategies in a uniform fashion.[16]

To provide states with additional flexibility, the rule also establishes state-specific rate-based CO_2 emission goals and mass-based CO_2 emission goals that represent the aggregate emission performance rates for each states' mix of affected EGUs.[17] The statewide rate-based emission goals represent the weighted aggregate of the source-specific emission performance rates applied to each state's affected EGUs.[18] For example, if a state only contains electric steam generating units, its rate-based goal would be 1,305 lbs. CO_2/MWh. In the west, these rate-based goals range from 771 lbs. CO_2/MWh in Idaho to 1,305 lbs. CO_2/MWh in Montana.[19] The statewide mass-based emission goals reflect the total aggregate CO_2 emissions each state's EGUs may emit during the compliance period.[20] In the west, these mass-based goals range from 8,118,654 tons of CO_2 in Oregon to 48,410,120 tons of CO_2 in California. States must meet phased-in emission performance rates or goals during an interim period from 2022 to 2029, and must achieve final compliance by 2030.[21]

In promulgating the Clean Power Plan, EPA sought to provide states with flexibility to cost-effectively reduce emissions while maintaining electric system reliability.[22] In accordance with this objective, the rule gives states the option of selecting one of two approaches for implementing the rule: an "emission standards approach" or a "state measures approach."[23]

Under the emission standards approach, a state may choose to adopt federally enforceable emission standards that apply directly to the state's affected EGUs.[24] These standards can either impose the nationally applicable emission performance rates on the state's EGUs, or establish customized rate-based or mass-based emission standards that enable the state to achieve its state-specific emission goal.[25] Both rate-based and mass-based emission standards must be quantifiable, verifiable, enforceable, non-duplicative, and permanent.[26]

TABLE 1

STATEWIDE RATE-BASED EMISSION PERFORMANCE GOALS (lbs. CO_2/MWh)

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COLORADO	1,476	1,332	1,233	1,362	**1,174**
IDAHO	877	817	784	784	**832**
MONTANA	1,671	1,500	1,380	1,534	**1,305**
NEVADA	1,001	924	877	942	**855**
NEW MEXICO	1,435	1,297	1,203	1,325	**1,146**
OREGON	1,026	945	896	964	**871**
UTAH	1,483	1,339	1,239	1,368	**1,179**
WASHINGTON	1,192	1,088	1,021	1,111	**983**
WYOMING	1,662	1,492	1,373	1,526	**1,299**

Data from Clean Power Plan Table 12

TABLE 2

STATEWIDE MASS-BASED EMISSION PERFORMANCE GOALS (tons CO_2)

STATE	INTERIM STEP 1 2022–2024	INTERIM STEP 2 2025–2027	INTERIM STEP 3 2028–2029	INTERIM GOAL 2029	FINAL GOAL 2030
ARIZONA	35,189,232	32,371,942	30,906,226	33,061,997	**30,170,750**
CALIFORNIA	53,500,107	50,080,840	48,736,877	51,027,075	**48,410,120**
COLORADO	35,785,322	32,654,483	30,891,824	33,387,883	**29,900,397**
IDAHO	1,615,518	1,522,826	1,493,052	1,550,142	**1,492,856**
MONTANA	13,776,601	12,500,563	11,749,574	12,791,330	**11,303,107**
NEVADA	15,076,534	14,072,636	13,652,612	14,344,092	**13,523,584**
NEW MEXICO	14,789,981	13,514,670	12,805,266	13,815,561	**12,412,602**
OREGON	9,097,720	8,477,658	8,209,589	8,643,164	**8,118,654**
UTAH	28,479,805	25,981,970	24,572,858	26,566,380	**23,778,193**
WASHINGTON	12,395,697	11,441,137	10,963,576	11,679,707	**10,739,172**
WYOMING	38,528,498	34,967,826	32,875,725	35,780,052	**31,634,412**

Data from Clean Power Plan Table 13

The state measures approach gives states additional flexibility to incorporate measures that are implemented by sources other than affected EGUs.[27] Under this approach, states have the option to adopt a combination of federally enforceable emission standards and state-enforceable measures that reduce power-sector emissions.[28] The state measures approach is only available for states pursuing mass-based emission goals, to ensure that these states are achieving their required emission reductions.[29] To implement this approach, a state must submit an implementation plan to EPA that identifies each state measure the state will apply and demonstrates that these measures will result in emission reductions that are quantifiable, verifiable, enforceable, non-duplicative, and permanent.[30] In addition, the plan must include a backstop of federally enforceable emission standards for all affected EGUs that will automatically be triggered if the state fails to reduce emissions on schedule.[31]

The Clean Power Plan also gives states the options to engage in market-based emission trading and coordinate compliance activities with other states. Emission trading is available to states implementing rate-based or mass-based programs. States with rate-based programs can establish trading programs for emission reduction credits (ERCs) that represent one megawatt-hour of zero-emitting electricity generation or reduced electricity use.[32] States with mass-based programs can establish trading programs for emission allowances that represent one ton of avoided CO_2 emissions.[33] EGUs may use either ERCs or emission allowances to meet their required emission rates or mass-based emission standards. States may issue ERCs or allowances for actions that reduce electricity generation and emissions at affected EGUs. These actions may include, for example, substituting zero-emitting generation for fossil fuel-fired generation or reducing consumption through demand-side efficiency. The Clean Power Plan also includes an option for states to participate in a Clean Energy Incentive Program (CEIP) that encourages early action to reduce emissions through deployment of renewable energy or energy efficiency.[34] Under this program, EPA will grant matching ERCs or emission allowances for wind or solar projects that commence construction after a state submits a plan to EPA and that generate megawatt-hours during 2020 and/or 2021, or demand-side efficiency projects that are implemented after the state submits its plan and that reduce end-use demand in low-income communities during 2020 and/or 2021.[35]

States are free to participate in emission trading programs with any other states implementing the same type of program (either rate-based or mass-based). States are not required to enter into a formal multi-state plan to engage in emission trading, but their implementation plans must indicate how they will track ERCs or emission allowances for compliance.[36] States also have the option of entering into formal multi-state plans that aggregate participating states' emission goals into a single joint goal that all participants must collectively achieve.[37] Multi-state plans can follow a mass-based or rate-based approach, but all states must implement the same approach.[38]

The final rule gives states one year to develop and submit implementation plans to EPA for approval. State plans are due on September 6, 2016, though states can file for an extension to September 6, 2018.[39] State plans must describe the state's chosen implementation approach, identify affected EGUs and inventory CO_2 emissions from these sources, and demonstrate how the plan will achieve the emission performance rates or state emission goals.[40] A state plan must also include monitoring, reporting, and recordkeeping requirements for EGUs, and describe the state's reporting and recordkeeping processes.[41] States must allow the public to participate in the plan development process, and must engage with vulnerable communities and other state energy agencies.[42] The final plan submission must include documentation outlining the state's legal authority and funding to implement the plan, identifying the state's programmatic milestones and timeline, and demonstrating how the state considered reliability during the plan development stage.[43]

The Clean Power Plan gives states the flexibility to implement both onsite and offsite emission reductions measures. This flexibility allows states to select the most cost-effective strategies for reducing power sector emissions. However, this flexibility also presents some potential implications for maintaining reliability in the bulk power grid. The electricity needs for the western United States are served through one connected power grid, which means that compliance activities in one state could impact the electricity systems in multiple other states.

In response to concerns that the Clean Power Plan may threaten the integrity of the bulk power system, EPA added a number of provisions to the final rule to support grid reliability. First, the rule provides flexibility in how states and EGUs comply with emission performance rates or state emission goals.[44] Second, the final rule provides an extended timeframe for demonstrating achievement of emission rates or goals.[45] Third, states must consider grid reliability when formulating their implementation plans.[46] Fourth, the rule allows states to revise their plans to address changes in circumstances that could impact reliability if not addressed.[47] Fifth, the rule includes a reliability safety valve that enables a specific EGU or multiple EGUs to temporarily comply with modified emission standards during emergency situations that threaten grid reliability.[48] And sixth, EPA, FERC, and the U.S. Department of Energy agreed to coordinate their efforts to help maintain grid reliability during the rule's implementation.[49]

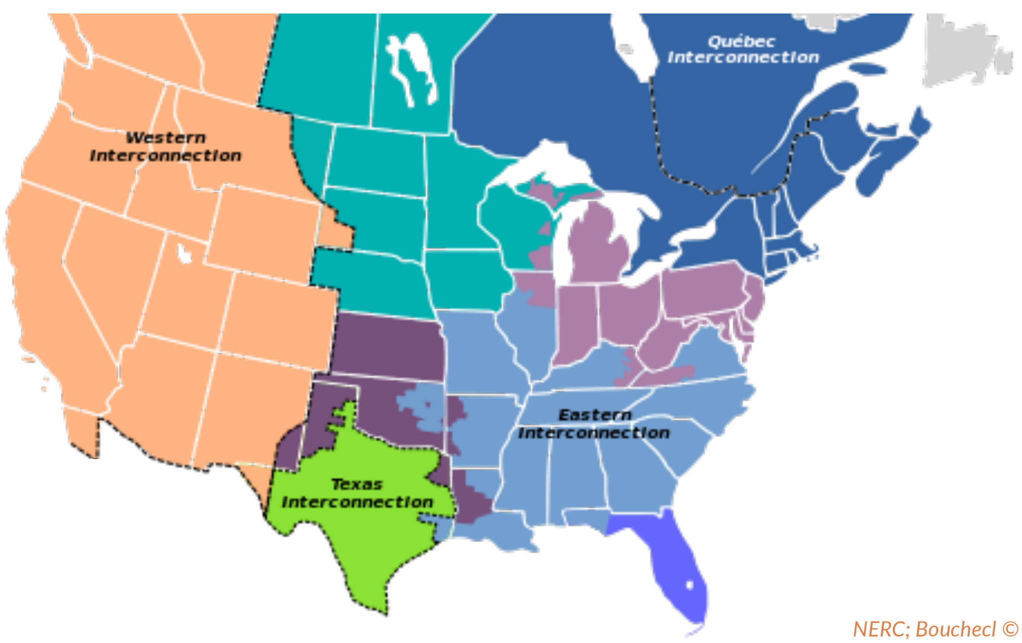
While Clean Power Plan compliance has the potential to impact the western grid as a whole, no regional regulatory body possesses comprehensive enforcement authority over state power sector decision-making. Instead, the western grid is governed by a complex regulatory framework under which local, state, and federal governments share jurisdictional authority. These entities must coordinate and cooperate with one another to ensure that Clean Power Plan compliance activities do not compromise the functionality or reliability of the western grid. The following section provides an overview of the jurisdictional and regulatory frameworks that govern grid operations in the west.

III. TRANSMISSION REGULATION IN THE WESTERN UNITED STATES

The Federal Energy Regulatory Commission (FERC) regulates the transmission and sale of electricity in interstate commerce,[50] which means that FERC has jurisdiction over wholesale transmission and unbundled retail transmission of electricity.[51] FERC does not have jurisdiction over retail sales of electricity (*i.e.* sales of electricity to end users) or over local electric distribution systems. The Energy Policy Act of 2005[52] authorized FERC to appoint an Electric Reliability Organization (ERO) to establish and enforce mandatory reliability standards for the national power grid.[53] In 2006, FERC certified the North American Electric Reliability Corporation (NERC), an independent non-profit organization, as the ERO for the North American power grid.[54] As the ERO for the grid, NERC develops and enforces mandatory reliability standards for the grid, subject to FERC oversight.[55] NERC also has the authority to propose civil fines of up to $1,000,000 per day for violations of grid reliability standards, which are subject to FERC oversight.[56]

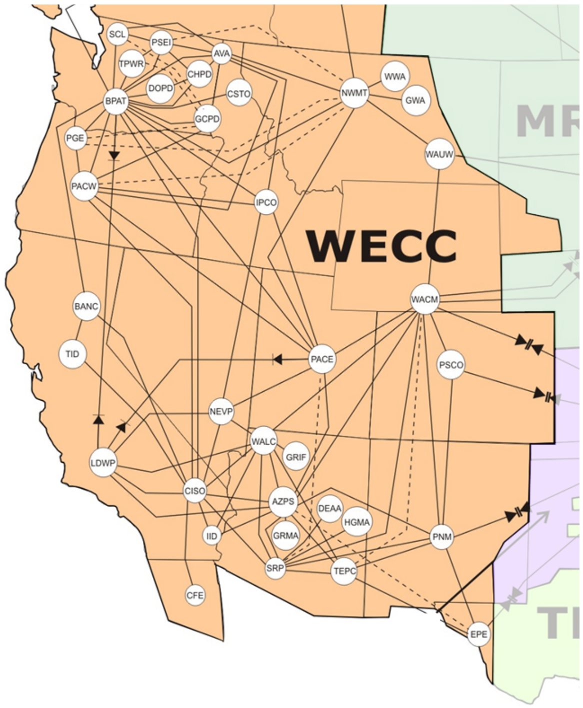
The electricity needs of the western United States are served through an electrical grid called the western interconnection, which runs primarily through eleven western states and also extends into portions of Canada and Mexico.[57] The Western Electricity Coordinating Council (WECC) is the FERC-approved regional reliability entity for the western interconnection.[58] As the regional

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION INTERCONNECTIONS



NERC; Bouchecl © 2009

BALANCING AUTHORITIES AND TRANSMISSION PATHWAYS IN THE WECC REGION



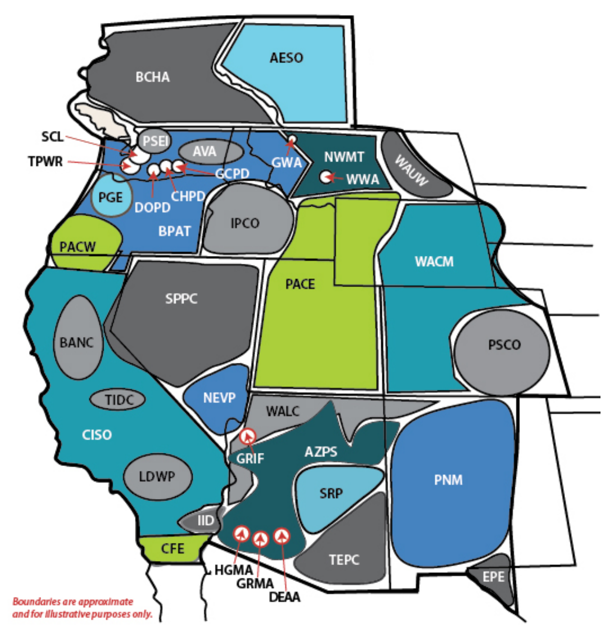
U.S. Energy Information Administration (2014)

reliability entity, WECC received authority from NERC to monitor and enforce reliability standards for the western grid.[59] In 2014, WECC partitioned off its reliability coordinator function and designated Peak Reliability—a new, independent company—as the reliability coordinator for the western grid.[60] WECC remains the regional reliability entity for the western grid, and therefore must ensure that the grid is "reliable, adequate, and secure."[61] WECC does not own or operate transmission assets; instead, WECC works with energy sector stakeholders to maintain stability and reliability in the grid. WECC also studies and evaluates grid operations and conducts long-term transmission system planning that assesses how the grid would function under a variety of plausible future scenarios. As the reliability coordinator for the grid, Peak Reliability has authority over the reliable operation of the grid and must ensure that grid operations comply with NERC and WECC reliability standards.[62]

With the exception of the California independent system operator (ISO),[63] the western grid does not have organized electricity markets. Instead, the western interconnection is divided into 38 balancing areas under the management of grid operators known as balancing authorities.[64] Balancing areas encompass all electricity generation, transmission, and demand ("load") within a specific geographic area. Balancing authorities are responsible for balancing power generation and load and maintaining transmission voltage and frequency within their respective balancing areas on a continuous basis. These balancing authorities balance supply and demand by dispatching or curtailing generating resources to accommodate real-time fluctuations in consumer demand. Balancing authorities also coordinate transfers of power between different balancing areas.

Western balancing authorities are comprised of investor-owned utilities,

WESTERN BALANCING AREAS



Western Electricity Coordinating Council (2013) consumer-owned utilities, independent power companies, and federal power marketing administrations.[65] These entities fall under the jurisdiction of various state and federal regulatory agencies. Investor-owned utilities are regulated by state-level public utility commissions (PUCs) or public service commissions (PSCs), which are state entities that regulate the rates and services of investor-owned utilities. PUCs do not have jurisdiction over consumer-owned utilities, which include public utility districts, electric cooperatives, and municipal utilities. These entities are governed by elected commissioners (in the case of public utility districts), consumer-members (in the case of electric cooperatives), and locally elected officials (in the case of municipal utilities).[66] Power marketing agencies, including the Bonneville Power Administration (BPA) and the Western Area Power Administration (WAPA), are federal nonprofit agencies within the U.S. Department of Energy, and thus are not under state regulatory jurisdiction. A balancing authority's classification thus determines the regulatory framework that will govern its activities.

The jurisdictional dynamic overlying this regulatory framework creates an extra layer of complexity for Clean Power Plan implementation in the west. Individual balancing authorities may fall under the jurisdiction of local, state, or federal electricity regulators, and states must ensure that divergent regulatory requirements will not interfere with their compliance efforts or threaten the reliability of the power system. Moreover, state and local utility regulators are not directly responsible for implementing the Clean Power Plan. Instead, state environmental and air quality agencies are tasked with implementing and enforcing air pollution standards under the Clean Air Act. These air quality agencies must collaborate with state utility regulators and energy agencies, local municipalities, and federal power marketing agencies to craft implementation plans that will comply with the Clean Power Plan while maintaining the functionality of the power sector. The following section explores how the rule's compliance obligations may impact the western grid.

U.S. Department of Energy (2013)

The federal Bonneville Power Administration operates more than 12,300 miles of transmission lines across eight western states and markets and delivers more than a third of the power consumed in the Northwest.

IV. IMPLEMENTING THE CLEAN POWER PLAN IN THE WEST

The Clean Power Plan has the potential to significantly alter the composition of the energy mix in the western United States. Because coal-fired power plants emit substantially more CO_2 than other generating resources, the rule incentivizes states to retire large amounts of coal-fired capacity to meet their compliance obligations. EPA anticipates that states will replace this coal capacity with a mix of natural gas, renewable energy, and demand-side management and energy efficiency measures.

Coal currently plays a significant role in the western electricity sector, and the transition from coal-fired generation to renewable energy will present some challenges for the western grid. Western states currently possess more than 32,000 megawatts (MW) of coal-fired generating capacity, which represents about 15% of the region's total resource mix.[67] However, the reliance on coal is much more pronounced on a state-by-state level; for example, nearly 89% of Wyoming's electricity came from coal in 2013.[68] The Clean Power Plan's rate- and mass-based state goals reflect the region's divergent reliance on coal-fired power. States with substantial coal-fired generation, such as Colorado, Montana, and Wyoming, are required to achieve much higher emission reductions than states with little to no coal-fired power, like Oregon and Idaho, and states with significant renewable energy resources, like California. The Clean Power Plan's mass-based emission goals reflect the overall quantities of fossil fuel-fired power each state generates. Wyoming has the highest mass-based reduction requirement in the west; in 2030, the state must emit 18,364,324 less tons of CO_2 than it emitted in 2012.[69] Washington has the lowest mass-based reduction requirement; the rule allows the state to increase emissions by 3,378,989 tons over its 2012 baseline.[70] The Clean Power Plan's rate-based emission goals reflect the carbon intensity of each state's generating units. Montana, which is home to the nation's second-largest coal-fired power plant, must reduce its emission rate 47.4% by 2030.[71] Idaho, which only has two natural gas-fired EGUs subject to the rule, must reduce its emissions by 7.6%.[72] The rule therefore requires the most coal-reliant western states to achieve the majority of the

The western United States contains a significant amount of coal-fired generating capacity, including PacifiCorp's 871 megawatt Dave Johnson plant in Glenrock, Wyoming. *Image credit: Greg Goebel © 2012.*

region's emission reductions.

As a result of the Clean Power Plan and other state and federal policies, EPA and WECC anticipate significant coal plant retirements in the western grid between 2010 and 2024.[73] Before taking the Clean Power Plan into account, WECC projected that 8,643 MW of coal generation will retire in the region by 2025.[74] The Clean Power Plan's first building block calls for states in the western grid to achieve an average heat rate improvement of 2.1% at coal-fired power plants,[75] which may be difficult or impossible for some western states to accomplish.[76] After interpreting EPA's proposed compliance options under the Agency's draft Clean Power Plan, WECC estimated that western states may collectively need to retire or re-dispatch an additional 3,900 MW of coal-fired capacity.[77]

WECC predicts that most of the retired coal capacity in the west will be replaced with natural gas combined cycle (NGCC) units,[78] and the Clean Power Plan's second building block calls for states to reduce power sector emissions by dispatching these lower-emitting natural gas units to replace coal-fired generation.[79] However, EPA determined that substantial shifting from coal to new natural gas generation would represent a deviation from the rule's requirements,[80] and the final rule limits states' abilities to replace existing coal-fired power with new NGCC units.[81] Moreover, pipeline constraints and natural gas price volatility could persuade regulators and utilities that investments in variable and non-variable renewable resources, energy efficiency, and demand response are more cost-effective options over the long term.

States that intend to attain compliance primarily through a shift from coal to natural gas should carefully consider how neighboring state compliance strategies could impact their own emissions rates. For example, in its preliminary review of the draft Clean Power Plan, WECC evaluated a hypothetical scenario in which western states imposed a price adder on carbon emissions.[82] WECC anticipated that as the price of carbon increased, carbon emissions in all states would decrease across the west. However, this was not the case—while carbon emissions decreased in some states, emissions increased in others. This is because states with low-cost, dispatchable resources, such as natural gas plants, were required to operate their units more frequently to compensate for reduced generation in other states. These factors and considerations indicate that replacing coal capacity with large amounts of natural gas capacity may

TABLE 3

STATE-BY-STATE 2012 EMISSION RATE BASELINES AND 2030 RATE-BASED EMISSION GOALS

STATE	2012 BASELINE EMISSION RATE (LBS. CO_2/MWH)	FINAL RATE-BASED GOAL (LBS. CO_2/MWH)	PERCENTAGE REDUCTION OVER 2012 BASELINE
ARIZONA	1,552	1,031	33.6%
CALIFORNIA	932	828	13.2%
COLORADO	1,973	1,174	38.3%
IDAHO	858	771	7.6%
MONTANA	2,481	1,305	47.4%
NEVADA	1,102	855	22.4%
NEW MEXICO	1,798	1,146	36.3%
OREGON	1,089	871	20%
UTAH	1,874	1,179	34.1%
WASHINGTON	1,566	983	37.2%
WYOMING	2,331	1,299	43.9%

Data from EPA Clean Power Plan State-Specific Factsheets (2015)

TABLE 4
STATE-BY-STATE 2012 EMISSION BASELINES AND 2030 MASS-BASED EMISSION GOALS

STATE	2012 BASELINE EMISSION MASS (SHORT TONS CO_2)	FINAL MASS-BASED GOAL (SHORT TONS CO_2)	DIFFERENCE BETWEEN BASELINE & FINAL GOAL
ARIZONA	40,465,035	30,170,750	–10,294,285
CALIFORNIA	46,100,664	48,410,120	+2,309,456
COLORADO	41,759,882	29,900,397	–11,859,485
IDAHO	703,517	1,492,856	+789,339
MONTANA	17,924,535	11,303,107	–6,621,428
NEVADA	15,536,730	13,523,584	–2,013,146
NEW MEXICO	17,339,683	12,412,602	+234,970
OREGON	7,659,775	8,118,654	+458,879
UTAH	30,445,732	23,778,193	–6,667,539
WASHINGTON	7,360,183	10,739,172	+3,378,989
WYOMING	49,998,736	31,634,412	–18,364,324

Data from EPA Clean Power Plan State-Specific Factsheets (2015)

not be the most prudent strategy to achieve the emissions reductions called for under the Clean Power Plan.

Renewable energy presents a low-risk alternative to new natural gas capacity, because renewable resources are not vulnerable to long-term cost increases resulting from carbon regulations or fuel price volatility. The Clean Power Plan urges states to deploy additional renewable generation; the rule's third building block calls for the region to reduce emissions by dispatching new zero-emitting renewable resources to replace fossil fuel-fired EGUs. This building block includes new generation from onshore wind, utility-scale solar PV, concentrating solar power, geothermal, and hydropower facilities.[83] Due to the interstate nature of renewable energy, EPA quantified renewable energy generation potential on a regional basis for building block 3.[84] In the west, these generation levels start at 56,663,541 megawatt-hours in 2022 and increase to 160,974,866 megawatt-hours in 2030.[85] These levels represent incremental, rather than total, renewable energy generation, which includes renewable generating capacity constructed after 2012.[86]

According to the renewable energy technical support document that accompanied the draft Clean Power Plan, the western region generated 68,065,726 megawatt-hours of renewable energy in 2012.[87] The Clean Power Plan calls for the region to generate 160,974,866 megawatt-hours of electricity from incremental renewable resources in 2030.[88] At first glance, these generation levels do not appear to exceed regional business-as-usual projections. For example, the WECC's 2012–2022 Common Case scenario, which predicts available generation, demand, and transmission capacity over a ten-year planning horizon, estimated that the western grid would produce approximately 169,000,000 megawatt-hours of renewable energy in 2022.[89] However, WECC's 2022 projection included total renewable energy generation, while the Clean Power Plan only credits the region for incremental renewable generation. Assuming that all of the renewable energy capacity operating in the region in 2012 remains operational in 2022, WECC's projection includes a little over 1,000,000 megawatt-hours of incremental generation in 2022. This generation would put the region well over its 2022 target of 56,663,541 megawatt-hours, but would fall far short of the region's 2030 target under the Clean Power Plan. Moreover, building block 3 merely represents the level of incremental renewable energy generation that EPA determined is achievable in the west during the rule's compliance timeframe. The rule incentivizes states to deploy additional renewable resources to achieve cost-effective emission reductions at affected EGUs. In addition, the rule's Clean Energy Incentive Program (CEIP) rewards states for early action in deploying renewable resources by providing matching emission allowances or ERCs for qualifying renewable energy projects that reduce emissions in 2020 or 2021.[90] Therefore, the region's renewable energy generation in 2030 may actually exceed both WECC's projections and the Clean Power Plan's building block 3 targets.

Western states collectively have the potential to generate a majority of the region's electricity from renewable sources. The National Renewable Energy Laboratory (NREL) and Western Governors' Association's Western Renewable Energy Zones (WREZ) initiative[91] identified a number of "hubs" throughout the western interconnection that have access to abundant, high-quality renewable resources.[92] These hubs represent areas with the potential to support large-scale renewable energy development without significant environmental impact. Phase 1 of the WREZ initiative identified more than 200,000 MW of high-quality wind, solar, geothermal, biomass, and hydropower resources within qualified resource areas across the western grid.[93] These WREZ hubs therefore have the potential to provide more than enough substitute energy to compensate for projected coal plant retirements under the Clean Power Plan. In fact, the WREZ hubs have the potential to produce enough renewable energy to satisfy more than 80% of the region's projected electricity needs.[94] According to NREL, it is technically feasible to integrate this amount of renewable energy onto the power grid.[95] However, the west will need to optimize the grid to support these variable resources.

The anticipated changes in the generation mix under the Clean Power Plan present challenges and opportunities for western states. As the next part of this report explains, replacing baseload coal power with variable renewable energy may create reliability and integration challenges for the grid. Part V discusses the mechanisms that affect reliability in the grid and describes EPA's efforts to mitigate potential reliability constraints under the final Clean Power Plan.

Ponnequin Wind Farm, Colorado. *Image credit: NREL (2006)*

V. RELIABILITY AND INTEGRATION CONCERNS

The North American Electric Reliability Corporation (NERC)—the electric reliability organization for the North American power grid—issued two reports assessing the potential reliability impacts of the EPA's draft Clean Power Plan.[96] NERC's assessments of the proposed rule expressed concerns that the Clean Power Plan could compromise the reliability of the U.S. power grid.[97] In its *Initial Reliability Review*, NERC discussed how changes in the generation mix under the Clean Power Plan, characterized by reductions in baseload coal-fired capacity and increases in natural gas and variable renewable capacity, may reduce overall reliability in the grid.[98] NERC's concerns stemmed from the understanding that baseload resources promote grid reliability and stability by providing power when electricity demand is high and reducing output when demand is low. Variable renewable resources, such as wind or solar power, generally cannot adjust their output to reflect changes in demand. Because grid operators must comply with NERC Reliability Standards[99] and ensure that power levels in the grid remain in balance at all times, managing variable renewable resources can be a challenge. In response to these concerns, EPA incorporated additional provisions into the final Clean Power Plan to help ensure that state implementation efforts do not compromise reliability within the interconnected electric system. These new provisions provide additional safeguards to protect grid reliability on a regional level.

The reliability of the grid is dependent on the grid operator's ability to balance load (*i.e.* energy demand) and supply (*i.e.* energy generation) within the transmission system at all times. Grid operators must also maintain voltage and frequency within permissible boundaries. Voltage is the difference in electrical charge between two points on the system, which represents the amount of potential energy between these two points. Voltage is analogous to the amount of water pressure in a garden hose. Frequency is the rate of the oscillations of alternating current in a transmission line. Frequency serves as an indicator that supply and demand are in balance across the system—if load greatly exceeds demand, the system frequency will drop, and if demand greatly exceeds load, system frequency will rise. Fluctuations in voltage or frequency indicate that there is an imbalance between generation and load on the system, and action must be taken to protect the reliability of the grid.

In the western grid, balancing authorities are responsible for harmonizing electricity supply and demand to ensure grid reliability.[100] These organizations maintain balance on the grid by controlling the dispatch of different generating resources, allocating transmission capacity within their balancing areas, and scheduling transfers of power between neighboring balancing areas.[101] To maintain reliability, grid operators generally rely on ancillary services, which FERC and NERC define as "those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Service Provider's transmission system in accordance with good utility practice."[102] Ancillary services are thus activities and services that facilitate transmission system operations and support the integrity and reliability of the grid. Voltage support and frequency

The intermittent nature of variable renewable energy sources, such as wind power, can create challenges for grid operators responsible for maintaining balance across the grid. *Image credit: U.S. Department of Energy/Iberdrola (2008)*

regulation are both examples of ancillary services.[103]

Wind and solar power are intermittent and variable resources, and therefore cannot currently provide consistent, predictable power generation for the grid. In contrast, coal-fired generating units provide baseload power, and grid operators can dispatch these resources in response to fluctuations in supply or demand. Coal-fired power plants thus provide both system voltage stability support and frequency response for the grid. When coal plants go offline and are replaced with renewables, the shift from dispatchable to variable generating resources may compromise the stability and reliability of the grid.

NERC is concerned that the Clean Power Plan's directive to shift from baseload coal to variable renewables may strain the grid's "Essential Reliability Services," which "are the elemental 'reliability building blocks' provided by generation, and in some cases by demand response, storage and other elements necessary to maintain BPS [bulk power system] reliability."[104] These Essential Reliability Services include load and resource balancing, voltage stability and frequency response, and ramping capability.[105] The following sections describe these services and functions and briefly discuss how increases in variable renewable generation may impact grid reliability. The final section discusses the provisions that EPA included in the final Clean Power Plan to protect grid reliability.

A. LOAD AND RESOURCE BALANCE, VOLTAGE STABILITY, AND FREQUENCY RESPONSE

Maintaining system voltage and frequency requires a constant balance between generation output and load on the grid. System voltage stability is the ability of the grid's resources (including generators and other voltage control devices) to maintain actual power levels within an acceptable range at every point in the transmission system.[106] If voltage is not maintained within an acceptable bandwidth, grid operations may falter and damage transmission infrastructure.[107] Frequency response is the grid's ability to stabilize frequency immediately following the sudden loss of generation or load.[108] Large fluctuations in frequency can also damage transmission equipment or cause grid operations to fail.[109] Voltage stability and frequency response are therefore essential to maintaining grid reliability.

Grid operators typically rely on coal and natural gas-fired power plants to provide reactive power for system voltage support and frequency response.[110] When these facilities go offline, their absence may create stability issues at the local or regional level.[111] Conventional coal-fired plants also traditionally provide inertia, or stored rotating energy, which helps to stabilize the system by reducing frequency declines following sudden and unexpected shifts in generation or load.[112] Because coal plants provide voltage stability and frequency response services, widespread coal retirements could impact reliability in the western grid.[113]

NERC has found that maintaining system balance can become increasingly difficult as additional variable generation resources are connected onto the grid.[114] The intermittent nature of renewable power generation makes it difficult for grid operators to respond to changes in load or generation input. Changes in the types or location of generating resources can also impact voltage stability.[115] Frequency response is dependent on generator flexibility to reduce or curtail output to maintain system stability, but variable renewables generally operate at full production.[116] The inherent intermittency of renewable energy resources such as wind and solar may therefore strain the grid's essential reliability services.

B. RAMPING CAPABILITY AND FLEXIBILITY

Conventional baseload generating units, such as coal plants, can adjust their output in response to changes in power demand. These units adjust their output through processes know as ramping and cycling. Ramping occurs when a generating unit increases output to meet load demands.[117] Cycling occurs when an offline unit is brought online to increase power supplies on the grid.[118] Grid operators rely on the ramping capability and flexibility of the generating fleet to maintain balance on the system.[119]

NERC is concerned that increased deployment of variable renewables will make it difficult for grid operators to maintain balance on the system, and will require additional ramping capability across the grid.[120] Increases in ramping and cycling of conventional generating resources can inflict wear and tear on these facilities, which in turn can contribute to higher operation and maintenance costs and more frequent repairs or forced outages.[121] This additional strain can potentially reduce the useful life of facility components.[122] Baseload power plants suffer the most strain and damage from increased ramping and cycling.[123] NERC's *Initial Reliability Review* expressed concern that the increased ramping and cycling necessary to integrate high levels of variable renewables under the Clean Power Plan could force the remaining baseload plants to go offline more frequently.[124] The reduced availability of these plants could necessitate higher operating reserve requirements, which require balancing authorities to have additional generating resources on hand to respond to unanticipated increases in load.[125]

THE NATIONAL RENEWABLE ENERGY LABORATORY'S WESTERN WIND AND SOLAR INTEGRATION STUDY

In Phase II of its Western Wind and Solar Integration Study, NREL calculated the wear-and-tear costs and emissions impacts of increased ramping and cycling under scenarios with high penetrations of variable renewables. NREL found that the western grid could integrate up to 33% wind and solar generation with minimal economic impacts from increased ramping and cycling at baseload plants. Specifically, NREL found that 33% wind and solar penetration caused cycling costs to increase by $0.47–$1.28 per megawatt hour (MWh) of conventional generation (or $0.14–$0.67 per MWh of renewable generation), but these costs were offset by reduced fuel costs of $28–$29 per MWh. On an annual basis, cycling costs in the western grid would increase by $35–$157 million, but these costs would be offset by fuel cost reductions of approximately $7 billion.

NREL operates the Department of Energy's National Wind Technology Center in Colorado. *Image credit: U.S. Dep't of Energy (2013)*

C. THE CLEAN POWER PLAN'S RELIABILITY SAFEGUARDS

In response to NERC's *Initial Reliability Review* and other comments reflecting concerns over the reliability implications presented by the draft Clean Power Plan, EPA made a number of changes to the final rule to support grid reliability. The Agency revised the final rule to provide states with sufficient flexibility and time to implement the rule and meet emission performance rates or state goals in a manner that maintains reliability within the electric system. EPA also added a series of reliability provisions to the final rule that direct states to consider reliability when developing their implementation plans, allow states to revise approved plans in response to potential reliability impacts, and provide a mechanism for reliability-critical affected EGUs to temporarily comply with modified emission standards. The Agency also committed to maintain on ongoing relationship with FERC and the U.S. Department of Energy to support grid reliability during the rule's implementation. This section describes the major reliability provisions included in the Clean Power Plan.

The Clean Power Plan includes three major provisions to support grid reliability. First, the rule requires states to consider reliability issues when developing their implementation plans.[126] Each submitted plan must document how the state considered reliability.[127] In the preamble to the final rule, EPA recommended that states consult with relevant planning and reliability authorities and document this consultation in their submissions.[128] EPA also recommended that each state should ask the planning authority to review its plan at least once during the development stage and assess any reliability implications apparent in the draft plan.[129] While the final rule does not require the state to follow the planning authority's recommendations, the state should document its responses to the planning authority's assessment.[130] EPA also recommended that states consult with their utility regulators and energy agencies during this reliability review.[131]

Second, the final rule allows states to modify their plans to address unexpected reliability issues. If an unanticipated and significant reliability issue arises during the implementation of an approved state plan, and the state is unable to address this issue within the confines of its plan, the state can submit a plan revision to EPA.[132] Unanticipated events could include, for example, the retirement of a large renewable energy generating unit.[133] The revised state plan must ensure that the state's affected EGUs comply with the rule's required emission performance level.[134]

Third, the final rule includes a reliability safety valve. If a state experiences a sudden, unforeseen emergency situation that substantially threatens grid reliability, the state can notify EPA that a specific affected EGU or group of EGUs must temporarily comply with modified emission standards.[135] This reliability safety valve triggers a 90-day period during which time the affected EGU or EGUs are exempt from their original emission standards, but still must comply with alternative standards.[136] During this 90-day period, any affected EGU's emissions will not count against the state's emissions goal or rates, and will not constitute an emission exceedance triggering corrective action.[137] If, after this 90-day period, the emergency circumstances persist and the EGU or EGUs remain reliability-constrained, the state must revise its plan to respond to ongoing reliability needs.[138] States must account for and offset any emissions occurring during this post-90-day period that exceed applicable goals or performance rates.[139]

The preamble to the final Clean Power Plan outlines the types of circumstances that could trigger the rule's reliability safety valve. First, the reliability safety valve can only be triggered by an unforeseeable, extraordinary, and "potentially catastrophic event."[140] Second, the safety valve is only available for an EGU or EGUs that must continue operating to prevent some form of failure within the system.[141] Third, the EGU's or EGUs' operations in response to the reliability emergency must result in emissions that violate the state plan's emissions requirements.[142]

EPA anticipates that market-based emission trading will largely prevent the types of reliability emergencies that would trigger the reliability safety valve.[143] The Agency believes that the flexibility afforded by the final rule should enable affected EGUs to meet their compliance obligations while maintaining reliability under fluctuating circumstances.[144] Therefore, if a state plan triggers the reliability safety valve more than once, the state must submit a revised plan to EPA that provides sufficient flexibility to prevent such reliability conflicts from occurring in the future.[145]

EPA is confident that the electric industry can successfully implement the Clean Power Plan while maintaining reliability within the system.[146] However, the Agency also recognizes that infrastructure and operational upgrades will likely be necessary to facilitate the integration of additional renewable capacity onto the grid.[147] As western states implement the Clean Power Plan, the reduction in baseload coal-fired capacity and deployment of new variable renewable capacity may initially strain the flexibility and reliability of the grid. However, western states can successfully mitigate these integration challenges by undertaking a coordinated, strategic effort to modernize the grid. Part VI explores strategies that may assist states in integrating variable renewable power onto the grid without compromising reliability.

VI. STRATEGIES TO SUPPORT GRID RELIABILITY UNDER THE CLEAN POWER PLAN

The western United States can successfully integrate high penetrations of renewable energy onto the grid without negatively impacting the reliability of the electric system. In its 2012 *Renewable Electricity Futures Study*, NREL concluded that renewable energy can provide 80% of the nation's electricity by 2050, and that the United States can effectively integrate high levels of variable renewable generation onto the grid.[148] To reach this level of renewable energy deployment, however, western states must upgrade the bulk electricity system to increase flexibility and maintain reliability throughout the grid. The Clean Power Plan provides an impetus for western states to modernize the grid, and EPA has incorporated sufficient flexibility and compliance timeframes into the final rule to enable states to implement the rule while maintaining grid reliability.[149] As EPA noted in the preamble to the final rule, the Clean Power Plan may actually serve to increase reliability within the system by encouraging states to reduce electricity demand, invest in new technologies, and upgrade grid operations and infrastructure.[150]

Grid operators can implement a number of operational practices and deploy available technologies to effectively integrate high levels of renewable energy onto the western grid. First, policymakers can encourage balancing authorities, power generators, and transmission owners to optimize grid operations to balance variable loads and maximize transmission and distribution capacity within the existing grid system. Second, policymakers can incentivize the energy sector to implement advanced technologies to increase transmission

NREL concluded that renewable energy could provide 80 percent of U.S. electricity by 2050. To integrate high levels of variable renewable power onto the system, western states must upgrade the grid to increase flexibility and maintain reliability. *Image credit: Dennis Schroeder/NREL (2014)* capacity on existing lines. Finally, policymakers can explore collaborative and market-based approaches that may increase the efficiency of the existing grid by providing real-time access to unused transmission capacity across the region.

The following sections introduce a variety of strategies that policymakers and grid operators can implement to support the integration of variable renewable generation without compromising grid reliability. Each subsection recommends a suite of policy options that should assist policymakers in implementing these strategies. The term "policymaker" is used broadly to describe legislative and regulatory decision makers at the local, state, and federal levels. The approaches discussed below focus on policies that aim to modernize grid operations and maximize available capacity in the existing transmission system. While optimizing the western grid to effectively integrate large quantities of variable renewable power will likely require substantial investments in new transmission infrastructure, this report focuses on strategies that make the most use of existing transmission lines.

Due to the complex jurisdictional dynamic governing the electricity sector, most of the policies introduced below will only be effective when implemented by the appropriate jurisdictional authority. Generally speaking, federal regulators (*i.e.* FERC) will have jurisdiction over policies involving interstate transmission access and pricing and the wholesale power market, while state legislatures and regulatory agencies will have jurisdiction over local electricity generation and distribution, transmission line siting, and retail power sales. Policymakers at all levels of government have authority to offer financial incentives to promote preferential activities, but state and local governments are often better positioned to adopt incentives that facilitate state compliance with the Clean Power Plan. Likewise, state utility regulators (*i.e.* PUCs) are best situated to adopt policies that promote or mandate specific action by investor-owned utilities. Efforts to modernize the western grid will therefore be most effective when policymakers from all levels of government work together to implement the strategies described below.

A. OPTIMIZE GRID OPERATIONS

To successfully integrate high levels of variable renewable energy onto the western grid without compromising reliability, policymakers can implement a variety of strategies to optimize operations within the existing grid to balance variable loads and maximize transmission capacity. These strategies include 1) promoting development of geographically diverse renewable resources; 2) improving wind and solar forecasting; 3) implementing intra-hour transmission scheduling; 4) enabling dynamic transfers of variable generation between balancing areas; 5) improving reserve sharing over larger geographic areas; and 6) orienting solar panels to stabilize output over longer periods of the day. The following subsections describe these strategies and the implications these approaches have for renewable energy integration. Each subsection also provides a list of policies that could help facilitate the implementation of these operational strategies. The policies introduced below offer general legal and regulatory mechanisms to support grid reliability under scenarios with high penetrations of variable renewable energy. Some policies represent options that may or may not provide optimal solutions in all jurisdictions, while other policies represent recommended courses of action for all jurisdictions.

1. PROMOTE GEOGRAPHIC DIVERSITY IN RENEWABLE ENERGY DEVELOPMENT

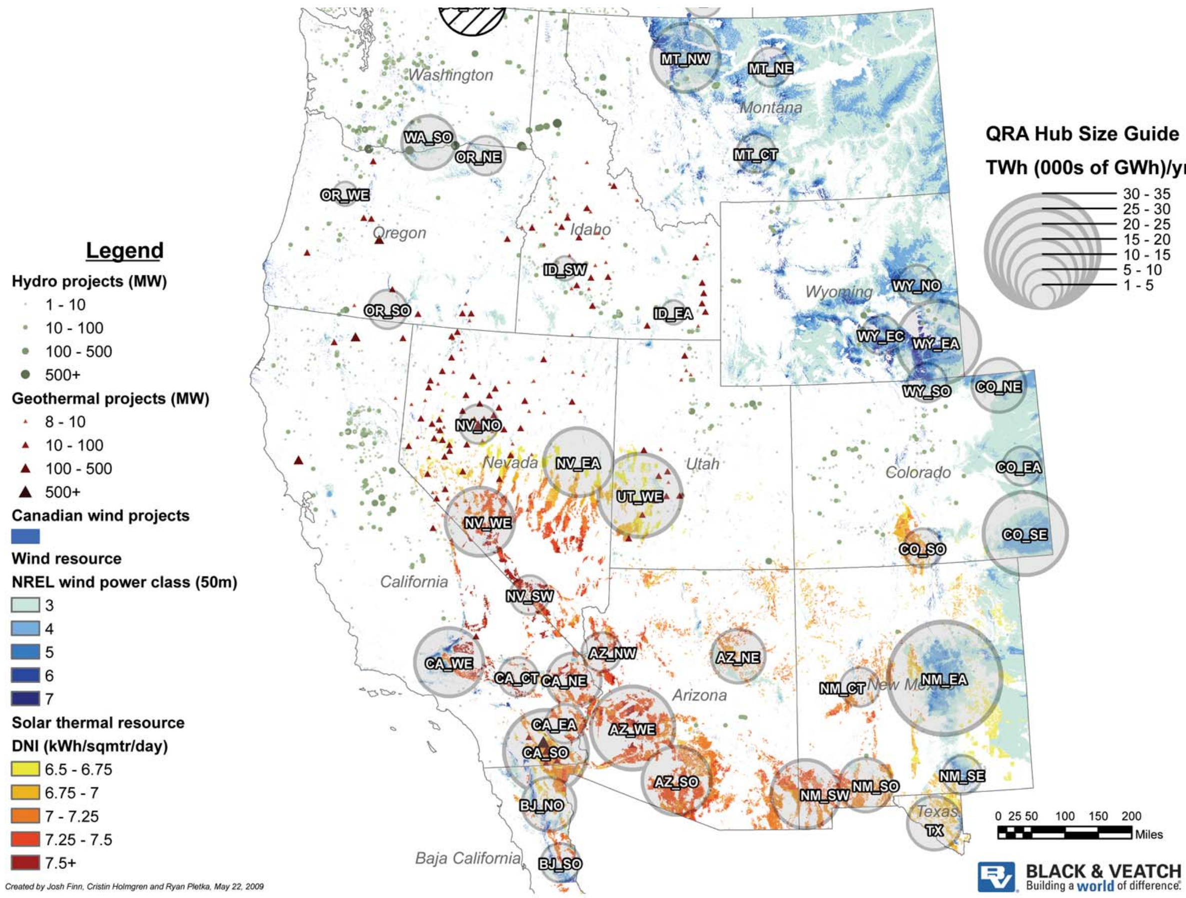
Regulators can minimize many of the reliability issues associated with variable renewables by promoting development of geographically diverse resources with varying hourly profiles. When a balancing area contains high levels of solar or wind capacity within a small geographic area, isolated shifts in resource availability due to changing weather conditions can significantly impact the local grid.[151] For example, during a sunny summer day, a 100-megawatt solar facility can transmit a substantial amount of power onto the grid, and unanticipated cloud cover can cause that resource to go offline with very little warning. If the balancing area contains multiple large solar arrays spread out over a large area, isolated cloud cover would have a much smaller impact on the grid. Wind power experiences similar benefits from geographic diversity, because wind speeds can vary significantly over large areas.[152]

The benefits of geographical diversity are even more pronounced when different types of variable renewable resources are spread out over multiple balancing areas. When multiple balancing areas cooperate with one another to coordinate variable renewable generation on a statewide, subregional, or regional basis, grid operators can balance large levels of variable generation while minimizing integration costs. When a large number of wind and solar generating facilities are balanced over a very large geographic area, the aggregate output from these facilities is fairly consistent. This reduced variability helps to minimize integration costs by reducing ramping requirements and the need for substantial balancing reserves.[153] It can also minimize negative impacts from localized forecasting errors.

The WREZ initiative discussed in Part III provides a useful starting point for identifying optimal renewable energy development sites over a broad geographic area. The initiative recognized the importance of geographic and resource diversity in deploying and integrating renewable energy capacity throughout the west.[154] Accordingly, the WREZ initiative aimed to identify optimal geographically diverse development sites across the region that have access to a variety of renewable energy resources.[155] During Phase 1 of the initiative, the WREZ researchers identified 38 "hubs" with substantial renewable energy potential within the U.S.-portion of the western interconnection.[156] Each state within the western region contains at least one renewable energy hub.[157] The WREZ initiative thus demonstrates the west's potential to develop a variety of renewable energy projects over a very large geographic area.

The downside of geographically diverse renewable development involves access to transmission. The western transmission system was not designed to connect geographically isolated areas to the grid, and the costs of building new transmission infrastructure may outweigh the benefits of dispersed development.[158] Utilities have little to no interest in investing in renewable energy facilities that lack sufficient transmission access,[159] and transmission expansion faces a number of hurdles in the west. New transmission lines are expensive to build, and the siting and permitting process typically spans many years. Transmission developers must also establish that there is a clear public need for the proposed transmission infrastructure.[160] States can mitigate many of these barriers by promoting comprehensive transmission planning and adopting policies to facilitate transmission development in geographically diverse WREZ hubs.

WESTERN RENEWABLE ENERGY ZONES INITIATIVE HUB MAP



Black & Veatch/Western Governors' Association/U.S. Dep't of Energy (2009)

Comprehensive transmission planning can help promote the strategic development of new transmission infrastructure to connect geographically diverse WREZ hubs to regional load centers. FERC's Order 1000 directs transmission providers to participate in a regional transmission planning process that considers transmission needs driven by public policy requirements.[161] Providers must therefore craft regional transmission plans that account for the additional renewable energy capacity needs stemming from the Clean Power Plan. During the planning process, balancing authorities should collaborate with state regulators to identify geographically diverse WREZ hubs with the greatest potential to facilitate Clean Power Plan compliance on a regional scale. The planning participants should then determine whether additional transmission infrastructure is needed to promote renewable energy development in these areas. State regulators should participate in the planning processes to ensure that long-term planning assumptions are consistent with state energy policies. The transmission planning process should also consider whether anticipated coal plant retirements will open up capacity in existing transmission lines.

To promote investment in new transmission to connect geographically diverse WREZ hubs to regional load centers, state policymakers can adopt laws and policies that mitigate some of the barriers to transmission development in the west. For example, state and local regulators can adopt uniform, streamlined processes for siting and permitting interstate transmission lines that access priority WREZ hubs. In addition, state PUCs can establish rebuttable presumptions that transmission projects connecting priority WREZ hubs to major load centers are needed and within the public interest. State policymakers can also offer financial incentives for renewable energy development in geographically diverse hubs.

In preparation for increased deployment of variable renewable resources under the Clean Power Plan, regulators should adopt policies or programs that incentivize development of geographically diverse resources. Prioritizing diversity in renewable energy deployment will reduce reliability constraints and associated integration costs and mitigate the impacts from localized weather events.

POLICIES TO INCENTIVIZE DEVELOPMENT OF GEOGRAPHICALLY DIVERSE RESOURCES:

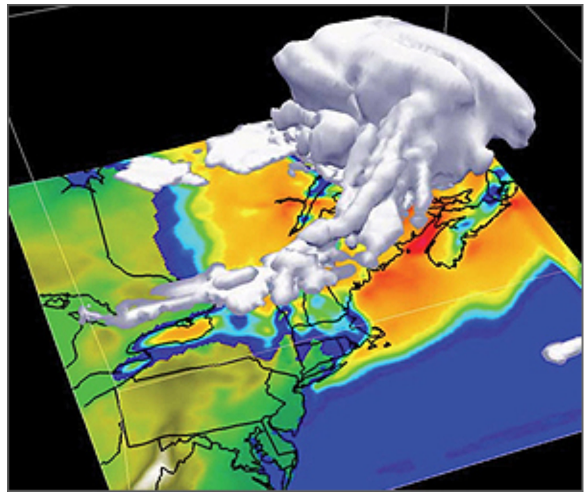
- FERC and state regulators should encourage regional transmission plans to address the benefits of geographically diverse renewable energy development in maintaining grid reliability under the Clean Power Plan.
- Federal, state, and local land use authorities should adopt coordinated siting, permitting, and approval processes that promote renewable energy development in WREZ-identified hubs and facilitate development of transmission infrastructure to connect these hubs to load centers.
- State PUCs should establish rebuttable presumptions that proposed transmission projects to connect priority WREZ hubs to major load centers are necessary and within the public interest.
- State PUCs should require regulated utilities to evaluate geographic diversity and long-term transmission constraints during the integrated resource planning process.
- State governments can revise renewable portfolio standards (RPSs) to include a renewable energy credit (REC) multiplier for projects developed within geographically diverse priority WREZ hubs.[162] For example, a project could earn 1.5 RECs for every megawatt-hour of output, rather than 1 REC per megawatt-hour.
- State and local governments can provide property tax exemptions for renewable energy projects in identified WREZ hubs.
- State and local governments can offer financial incentives in the form of rebates or tax credits for development in identified WREZ hubs.
- State PUCs can adopt streamlined interconnection procedures for projects in identified WREZ hubs.[163]

2. IMPROVE WIND AND SOLAR FORECASTING

Grid operators can also support grid reliability under the Clean Power Plan by improving wind and solar forecasting. Wind availability varies significantly over hourly and daily timeframes, which forces grid operators to make rapid adjustments to accommodate fluctuating output. Operators generally must keep other generating resources on reserve to provide back-up power for low-wind periods, which can add significant cost on a per-megawatt-hour basis. Grid operators may also have to curtail other generation to free up transmission capacity during high wind periods. Solar power is generally more predictable and reliable than wind power, though passing cloud cover can impact solar output during daylight hours.

Grid operators can reduce uncertainty and more accurately project renewable energy availability by implementing improved weather forecasting. Modern forecasting tools integrate data on real-time weather conditions, meteorological predictions, and renewable generating facility performance to estimate power availability over sub-hourly to daily timeframes. Improved forecasting enables grid operators to reduce operating reserves and schedule additional generation to reflect projected renewable output.[164] It also can provide grid operators with additional time to prepare for intense weather conditions that may cause extreme fluctuations in renewable output or damage generating equipment.[165]

Improved forecasting tools also allow grid operators to more cost-effectively integrate variable renewable energy onto the grid. Xcel Energy Colorado provides one example of how improved forecasting can help utilities integrate wind energy onto the grid at lower cost. Xcel currently has nearly 2,200 megawatts of wind power capacity, which satisfied more than 18% of the utility's total annual load in 2013,[166] and provided more than 60% of Xcel's power supply during one hour in May of that year.[167] In collaboration with Global Weather Corp., an affiliate of the National Center for Atmospheric Research (NCAR), Xcel developed WindWX, which the utility's website describes as "the most advanced wind-production forecasting system in the world."[168] The NCAR system integrates data from satellites, aircraft, radar, weather stations, and sensors installed on the wind turbines. This data is then run through a series of models and forecasting systems to create updated wind forecasts every 15 minutes.[169] The advanced forecasting system is 35% more accurate



Improved wind forecasting enables operators to reduce wind power integration costs. *Image credit: NREL*

than the utility's previous forecasting methods.[170] Since implementing WindWX in 2009, Xcel estimates that the system has saved the utility's ratepayers $20.7 million in fuel costs.[171]

Idaho Power Company has also implemented an advanced wind forecasting system that has reduced the utility's wind integration costs. Wind power provides a significant portion of Idaho Power's total generation: in 2013, around 10% of the utility's delivered power came from wind, and under certain conditions wind power can contribute 35% of the utility's generation.[172] To help reduce the costs associated with integrating this amount of wind power, Idaho Power developed a Renewables Integration Tool (RIT) that allows the utility to better predict wind energy availability up to 180 hours into the future.[173] The RIT integrates a number of models and databases to forecast wind conditions and project wind energy availability on an hourly basis. The model evaluates data on weather conditions, turbine performance, and supply and demand conditions within Idaho Power's service territory.[174] During the first three months of 2014, the RIT improved the accuracy of the utility's wind forecasts by 26% to 32%, which reduced the company's grid integration and operating costs by $287,000.[175]

In preparation for increased deployment of variable renewable resources under the Clean Power Plan, policymakers and balancing authorities should implement policies and programs to facilitate improved wind and solar forecasting. Improved forecasting should support grid reliability by increasing the accuracy of generation projections, which enables grid operators to reduce operating reserves, prepare for intense weather conditions, and increase the accuracy of transmission scheduling.

POLICIES TO FACILITATE IMPROVED WIND AND SOLAR FORECASTING:

- State governments and federal regulators can provide financial assistance for developing forecast models and installing modeling equipment. For example, Idaho Power's RIT was developed under a Smart Grid Investment Grant administered by the U.S. Department of Energy. The project received $47 million in funding under the American Recovery and Reinvestment Act of 2009.[176]
- State and local governments can fund and install meteorological towers in areas identified as optimal locations for current and future wind and solar development.
- State PUCs should issue rules directing balancing areas and power producers to share forecast data.[177]
- State PUCs should revise integrated resource planning rules to direct utilities to use advanced forecasting practices and authorize the PUC to withhold acknowledgment of integrated resource plans that fail to include advanced forecasting systems.
- In utility ratemaking proceedings, state PUCs should disallow a utility from recovering costs associated with integrating renewable resources if the utility failed to implement advanced forecasting systems and practices.

3. IMPLEMENT SUB-HOURLY TRANSMISSION SCHEDULING AND ENCOURAGE SALES OF SUB-MEGAWATT TRANSMISSION SERVICE

When renewable generators want to sell their output through the high-voltage transmission system, they must purchase transmission service and schedule the amount of power they wish to transmit over the system. Transmission capacity is purchased from a transmission provider under the terms of its Open Access Transmission Tariff (OATT). Transmission service must be scheduled in advance and documented with a NERC e-tag.[178] Independent renewable power producers are generally required to purchase transmission service in one-hour increments for whole megawatt blocks of capacity. This system places many renewable power producers at a disadvantage, because it is difficult to deliver a scheduled amount of variable renewable power at regular hourly intervals. FERC's Order 764 aimed to eliminate this constraint by requiring transmission providers to offer sub-hourly transmission scheduling in 15-minute intervals.[179] However, Order 764 does not require transmission providers to sell transmission service in sub-hourly intervals.[180] This means that renewable power generators must purchase an hourly block of transmission service before it can schedule power deliveries in 15-minute intervals.[181] Moreover, sub-hourly scheduling does not appear to be uniformly available to all renewable power producers on the western grid, which may have a negative impact on grid reliability when producers are unable to deliver their pre-scheduled megawatts on an hour-to-hour basis.[182] A distribution utility may also refuse to purchase more renewable power than a producer initially scheduled to deliver, which can lead to an excess of power across the transmission system. To integrate increasing quantities of variable renewable power onto the grid, state and federal regulators must ensure that renewable power producers have access to sub-hourly transmission services and should direct distribution utilities to accept renewable power deliveries that exceed pre-scheduled megawatt increments.

Independent power producers typically commit to sell their output to distribution utilities by entering into power purchase agreements with the purchasing utilities. Power purchase agreements generally specify that the power producer will deliver its output to the distribution utility in pre-determined megawatt blocks, and require the power producer to procure firm transmission rights for the life of the contract.[183] Transmission providers generally sell transmission service in hourly blocks,[184] and providers traditionally scheduled transmission capacity in one-hour intervals.[185] FERC's Order 764 subsequently amended the Commission's pro forma OATT to give all transmission customers the option of scheduling transmission in 15-minute increments.[186] However, Order 764 does not require transmission providers to sell transmission service in sub-hourly increments. Moreover, there is evidence that some independent renewable power producers may lack access to 15-minute scheduling under the terms of their power purchase agreements.[187] In addition, because power purchase agreements typically specify that producers will deliver power in whole megawatt increments, independent renewable generators must purchase transmission service in megawatt increments.[188] These requirements can represent significant barriers for independent renewable energy generators, because they may not be capable of transmitting a predetermined amount of power at a

Hourly transmission scheduling and whole megawatt delivery requirements may impose significant constraints on independent renewable power producers. *Image credit: U.S. Dep't of Energy (2012)* prescheduled time. Output from variable renewable resources may fluctuate on an hourly or sub-hourly basis, and thus generators may not be able to deliver one megawatt of power between 9:00 and 10:00 a.m., for example. This lack of flexibility can also create challenges for grid operators, who must dispatch reserve generation to compensate for shortfalls in renewable output that was scheduled but not delivered.

In issuing Order 764, FERC determined that hourly transmission scheduling requirements were not just and reasonable and may expose variable renewable energy generators to discriminatory imbalance rates.[189] Order 764 therefore required transmission providers to revise their OATTs to give all generators the option of scheduling transmission service in 15-minute intervals.[190] Western balancing authorities have now revised their OATTs to permit 15-minute scheduling in accordance with Order 764,[191] but individual utilities may still prevent variable renewable generators from using 15-minute scheduling under the terms of existing power purchase agreements.[192] For example, Portland General Electric (PGE) refused to allow PáTu Wind Farm to use 15-minute scheduling, because the wind generator's contract with the utility provided for hourly scheduling over the life of the agreement.[193] PGE argued that this refusal did not conflict with Order 764, because Order 764 only applies to transmission customers, and PáTu was not a transmission customer under PGE's OATT.[194] The utility instead insisted that PGE's merchant function[195] was the actual transmission customer under the OATT, because it took delivery of PáTu's output and then purchased transmission service from PGE's transmission function to deliver the wind power to PGE's customers.[196]

The Oregon PUC agreed with PGE and found that 15-minute scheduling would be inconsistent with the terms of PáTu's contract with PGE.[197] However, FERC subsequently determined that PGE was required to purchase PáTu's entire output pursuant to the terms of the contract between the wind farm and the utility, and thus ruled in favor of PáTu.[198] FERC also held that the Public Utility Regulatory Policies Act (PURPA) directed PGE to purchase all of PáTu's output, because the wind farm was a qualifying facility under that statute, and FERC's regulations require a utility to purchase "any energy and capacity which is made available from a qualifying facility."[199]

FERC's holding would appear to mitigate the constraints imposed by hourly scheduling requirements. However, FERC declined to rule on whether PGE's refusal to treat PáTu as a transmission customer violated Order 764, and FERC's decision did not clarify whether an hourly scheduling requirement would be permissible if PáTu was not a qualifying facility under PURPA and the contract explicitly called for hourly scheduling.

Even if FERC's Order 764 and its subsequent PáTu decision conclusively establish that renewable power producers are entitled to sub-hourly transmission scheduling, FERC has not eliminated the limitations imposed by sales of hourly transmission service. In order for a small renewable generator to schedule transmission in 15-minute increments, it must purchase a full hour of transmission capacity for whole megawatts of generation. Idaho Power, for example, charges a full hourly rate for sub-hourly transmission purchases and does not permit power producers to resell unused intra-hour transmission.[200] In a 2014 report for the Energy Trust of Oregon, author Ken Dragoon found that hourly scheduling and whole megawatt delivery requirements were still significant constraints for small renewable power generators.[201] The three power producers interviewed for the report all scheduled transmission services through Bonneville Power Administration (BPA) in hourly intervals and megawatt increments.[202] These requirements imposed substantial additional costs on the small power producers—for example, one generator was forced to reserve four megawatts of firm transmission service even though the facility only produces three megawatts of power two-thirds of the time.[203]

To facilitate the integration of greater quantities of variable renewable energy onto the western grid, transmission providers must allow renewable generators to schedule and purchase transmission capacity in sub-hourly blocks.[204] To minimize the burdens imposed by whole megawatt delivery requirements, grid operators could instead allow generators to schedule power deliveries in sub-megawatt (or kilowatt) increments rather than whole megawatt increments. If scheduling transmission service on a kilowatt basis is too burdensome for balancing authorities, an alternative would be to allow renewable generators to average their output over a monthly or annual timeframe.[205]

POLICIES TO FACILITATE SUB-HOURLY SCHEDULING AND ENCOURAGE SALES OF SUB-MEGAWATT TRANSMISSION SERVICE:

- FERC should amend Order 764 to require transmission providers to sell transmission services in sub-hourly increments.
- FERC should clarify that power producers are transmission customers under Order 764 and that utilities cannot treat their merchant function as a transmission customer to avoid offering 15-minute scheduling.
- State PUCs should require that utilities purchasing power from qualifying facilities under PURPA must accept all power produced by the qualifying facility. State PUCs should also prohibit utilities from refusing to accept power deliveries on the grounds that transmission was scheduled in sub-hourly intervals or in sub-megawatt increments.
- State PUCs should encourage jurisdictional balancing authorities to schedule transmission service in sub-megawatt increments or permit generators to average their output on a monthly or annual basis.

4. ENABLE DYNAMIC TRANSFERS OF VARIABLE GENERATION BETWEEN BALANCING AREAS

Balancing authorities routinely schedule transfers of power between balancing areas. If one balancing area's power demands exceed available generation, the balancing authority can call on generators in a neighboring balancing area to increase their output to satisfy demand in the receiving balancing area.[206] This is referred to as a *static transfer* of generation.[207] In the western grid, balancing areas typically schedule static transfers in standard one-hour intervals, which is referred to as *static scheduling*.[208] Static scheduling suffers from the same lack of flexibility as the hourly transmission scheduling discussed above. Dynamic transfers are an alternative to static scheduling that enable balancing authorities to transfer power from one balancing area to another in real-time.[209] Dynamic transfers offer a more flexible alternative to static transfers.

Dynamic transfers employ intra-hour scheduling to exchange and balance variability in renewable power output across a broad geographic area.[210] This operational mechanism allows power to flow freely between balancing areas to reflect variable renewable output. For example, if one balancing area experiences high wind speeds and the resulting wind power exceeds the

GREEN ENERGY INSTITUTE AT LEWIS & CLARK LAW SCHOOL area's load demands, the balancing authority can dynamically transfer excess generation to a neighboring balancing area. Dynamic transfers thus allow balancing areas to efficiently integrate variable renewable output onto the grid and support greater geographic diversity of wind and solar generating facilities.[211] More importantly, they can allow grid operators to integrate large amounts of renewable energy onto the grid without compromising reliability.

In the western grid, dynamic transfers have been employed reliably on a modest scale for many years.[212] However, as renewable power generation increases and requests for dynamic transfers increase, this operational tool could strain the reliability of the grid. The Western Governors' Association identified some concerns over the increased use of dynamic transfers, which included displacement of scheduled transmission transactions, increases in intra-hour fluctuations in power and voltage across the transmission system, and negative impacts on transmission operating limits.[213] Grid operators can avoid many of these negative outcomes by optimizing the grid's ability to automatically respond to intra-hour variations in power and voltage between balancing areas.[214] In addition, NERC's reliability standards for dynamic transfers require balancing authorities to formally request and arrange for dynamic transfers and account for these transfers in congestion management procedures.[215]

In preparation for increased deployment of variable renewable resources under the Clean Power Plan, regulators and balancing authorities should implement policies to facilitate dynamic transfers between other balancing areas in the region. Dynamic transfers support grid reliability by enabling balancing authorities to balance variable generation over a larger geographic area.

POLICIES TO FACILITATE DYNAMIC TRANSFERS OF VARIABLE RENEWABLE POWER:

- State governments can offer economic incentives for grid upgrades that facilitate dynamic transfers to provide grid reliability benefits to state residents.[216]
- State PUC regulations should direct utilities to accept dynamic transfers of variable renewable output under standard offer contracts.[217]
- State PUCs should incentivize automation of grid reliability functions and allow utilities to earn a rate of return on investments in transmission system upgrades that facilitate dynamic transfers and will provide reliability benefits for ratepayers.[218]
- State PUCs and regional and sub-regional grid reliability organizations should encourage sharing of system and meteorological data between balancing areas.

5. IMPROVE RESERVE SHARING OVER LARGER GEOGRAPHIC AREAS

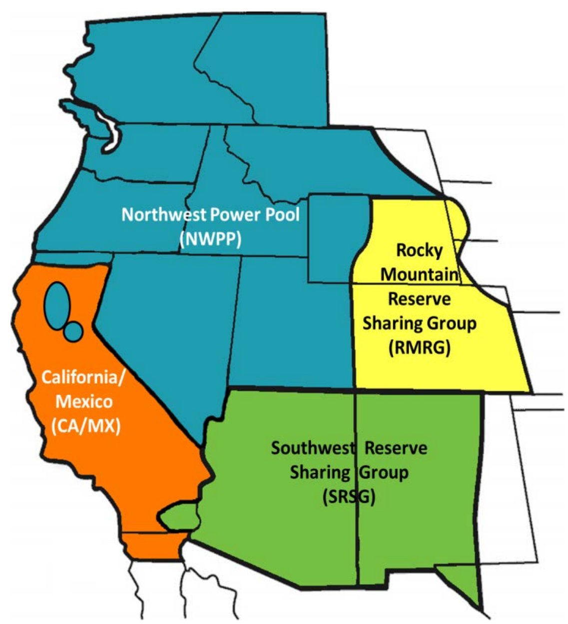
Balancing authorities maintain reliability by deploying reserves of generation or curtailing load as needed to balance power supply and demand on the grid or respond to unanticipated events. Grid operators deploy balancing reserves to balance daily fluctuations in generation and load and deploy contingency reserves in response to sudden and unexpected shifts in generation or load.[219] As additional renewable generation is deployed across the region, grid operators must have access to sufficient balancing and contingency reserves to respond to the variable output from these resources. To reduce the need for additional generating reserves, balancing authorities can share their reserves with other balancing areas in the region. Sharing balancing and contingency reserves supports grid reliability by enabling grid operators to respond to imbalances or disturbances on the grid by dispatching the most efficient available generating resources.[220] Western balancing authorities already share contingency reserves through reserve sharing groups, but these groups do not currently share balancing reserves between all participants.[221] By sharing both balancing and contingency reserves over a regional or sub-regional level, balancing areas should be capable of integrating greater quantities of variable renewable power while reducing costs.

NERC and WECC have adopted mandatory reliability standards requiring each balancing authority to carry contingency reserves.[222] These standards require every balancing authority to "have access to and/or operate" reserve capacity to respond to contingencies or disturbances.[223] WECC's standards specify that, at a minimum, balancing authorities must have sufficient contingency reserves to cover power losses from "the most severe single contingency" or "three percent of hourly integrated Load plus three percent of hourly integrated generation," whichever is greater.[224] Contingency resources can include generation; interchange transactions; controllable load resources, including demand response or demand-side management; or any other resources capable of providing energy or reducing energy consumption.[225] Both NERC and WECC standards allow balancing authorities to comply with contingency reserve requirements through participation in a reserve sharing group.[226]

Reserve sharing groups allow participants to request additional contingency reserves from other participating balancing authorities to respond to a contingency or disturbance.[227] Most of the balancing authorities in the western interconnection participate in a reserve sharing group. The Northwest Power Pool (NWPP) operates the largest reserve sharing program in the western grid.[228] Balancing authorities in Arizona, New Mexico, southern Nevada, southern California, and El Paso, Texas, participate in the Southwest Reserve Sharing Group.[229] Balancing authorities in Colorado, Wyoming, and portions of New Mexico, Nebraska, and South Dakota participate in the Rocky Mountain Reserve Group.[230] These groups share contingency reserves between participating balancing authorities, but do not currently share balancing reserves to respond to short-term fluctuations in generation or load.[231] Moreover, western contingency reserve sharing agreements do not permit reserve sharing in response to sudden drops in wind power output resulting from reductions in wind speeds.[232]

NERC reliability standards also require balancing authorities to maintain grid frequency within predefined limits by balancing real-time power supply and demand across the system.[233] On April 16, 2015, FERC approved NERC Reliability

RESERVE SHARING GROUPS IN THE WESTERN INTERCONNECTION



WECC © 2014

Standard BAL-001-2,[234] which authorizes balancing areas to enter into regulation reserve sharing groups that allow participants to share regulating reserves necessary to maintain frequency in the grid.[235] Regulating reserves are resources that can be dispatched automatically (using Automatic Generation Control, or AGC) to maintain frequency on the system.[236] Reliability Standard BAL-001-2 will go into effect on July 1, 2016,[237] at which time western balancing authorities will have an additional avenue for sharing balancing reserves. However, NERC Guidance emphasizes that balancing areas must implement a number of systems and practices to facilitate regulation reserve sharing, including real-time data sharing and dynamic scheduling.[238] In addition, power producers must install AGC systems at regulation-providing generating facilities, which can include renewable resources. For example, two-thirds of Xcel Energy Colorado's wind turbines are equipped with AGC systems and thus provide regulation for the utility's system.[239]

A number of operational practices can facilitate reserve sharing between balancing areas to support the integration of variable renewable resources. For example, sub-hourly scheduling and dynamic transfers support reserve sharing between balancing areas. In addition, a group of western electricity and transmission providers participate in a program called the ACE Diversity Interchange (ADI),[240] which allows participating balancing areas to pool their control errors and net out their momentary power surpluses or deficits and instantaneously share up to 30 megawatts of balancing reserves.[241] According to the Western Governors' Association, the ADI program cost participants less than $200,000 to implement in 2012 and reduced wear and tear on reserve generating units due to reductions in cycling and ramping.[242]

Reserve sharing groups can also potentially deploy contingency reserves in response to extreme weather conditions (such as a sudden drop in wind power output), which could reduce local balancing reserve needs.[243] To do so, however, the NWPP and the Southwest Reserve Sharing Group (SWRG) will first need to revise their contingency reserve sharing agreements to include wind speed-related ramp downs as qualifying contingency events or losses.[244] The NWPP and SWRG reserve sharing agreements currently limit the types of wind ramp downs that qualify for contingency reserve sharing. Both agreements designate wind power losses resulting from high wind speeds or extreme temperatures as qualifying generation losses, but exclude wind power losses resulting from reduced wind speeds.[245]

As variable renewable energy capacity increases throughout the west, reserve sharing over larger geographic areas may significantly reduce operating costs by enabling participants to pool their balancing and contingency reserves.[246] Under a scenario with 10% renewable energy penetration, the 2010 *Western Wind and Solar Integration Study* found that regional operating costs were reduced by $2 billion when reserves were shared between five large balancing regions.[247] Reserve sharing also can help reduce the aggregate variability of renewable power by allowing balancing areas to access geographically diverse resources to balance local fluctuations in output.[248]

In preparation for increased deployment of variable renewable resources under the Clean Power Plan, balancing authorities should implement programs and enter into agreements to better facilitate reserve sharing on a regional or sub-regional scale. Reserve sharing should enable balancing authorities to reduce the costs of integrating variable renewable resources by pooling balancing and contingency reserves. In addition, improved reserve sharing will help mitigate generation and load imbalances caused by variable renewable output by averaging short-term fluctuations over a larger geographic area.

POLICIES TO IMPROVE RESERVE SHARING:

- FERC should require contingency reserve sharing programs to authorize deployment of contingency reserves in response to ramp downs resulting from severe weather conditions.
- Balancing authorities can enter into regulation reserve sharing groups to automatically dispatch reserves from participating balancing authorities to maintain frequency on the grid.
- Reserve sharing groups should permit the sharing of contingency reserves to respond to imbalances due to wind power losses resulting from sudden drops in wind speeds.[249]
- State PUCs should encourage jurisdictional balancing authorities to participate in the ADI. Under the ACE Diversity Interchange Agreement, any western balancing area that is adjacent to and interconnected with any of the ADI parties can participate in the program.[250]

6. POSITION SOLAR PANELS TO INCREASE OUTPUT DURING PEAK DEMAND PERIODS

Solar PV installations typically face the south, because this orientation maximizes power production over the course of the day. However, increased deployment of exclusively south-facing solar panels may place additional pressure onto the grid, because the output from these systems generally does not coincide with peak power demand. Solar power reduces net energy demand on the grid during the daylight hours; however, as solar outputs begin to decline in the late afternoon, power demands begin to increase across the grid. This loss of solar output, combined with increasing demand, contributes to a rapid increase in load during the evening peak demand period. This dynamic is referred to as the “duck curve,” because the daily demand curve resembles the shape of a duck.[251] The duck curve presents a challenge for grid operators, who must quickly dispatch peaking generating units to satisfy the rapid increase in evening demand. To maintain reliability during peak demand periods, grid operators must have access to sufficient peaking capacity with flexible ramping capabilities. These facilities tend to be expensive, inefficient, and polluting natural gas plants.[252] To support grid reliability under the Clean Power Plan, western states should encourage the installation of both west and south facing solar PV systems to help soften the transition between declining solar output and increasing demand.

Because west-facing panels produce more power between the hours of 3:00 p.m. and 7:00 p.m., orienting solar PV systems towards the west, in addition to the south, helps to slow the rapid increase in load during the peak evening demand period.[253] This shift in output is even more pronounced on a seasonal basis. A study in Austin, Texas, for example, found that west-facing panels produced 25% more power between 3:00 p.m. and 7:00 p.m. over the winter months, and 70% more power during those hours in the summer.[254] The increase in summertime output is significant, because it can help to offset peak loads associated with afternoon air conditioning use. By shifting peak summer demand to later in the evening, west-facing solar panels can reduce the need for expensive gas peaker plants and ease reliability constraints on the grid.

However, homeowners have little incentive to orient solar panels towards the west, because south-facing systems out-perform west-facing systems on an annual basis.[255] To encourage solar energy production during late afternoon hours, the California Energy Commission adopted an additional economic incentive for west-facing solar PV installations on new homes.[256] Developers in the state can now receive a 15% premium—up to $500—for west-facing systems. The new incentive is in addition to the state's existing solar incentives under the California Solar Initiative.[257] However, existing homes are not eligible to receive the added incentive, so the program may not provide enough of a benefit to encourage homeowners to install solar on existing west-facing roofs.

Policymakers throughout the region should consider adopting policies that promote the installation of west-facing solar panels to increase afternoon solar output. While south-facing solar systems produce the greatest total output, orienting a portion of area solar PV systems to face the west or southwest can reduce the strain that declining solar output, combined with afternoon peak demand, imposes on the grid.

Installing solar panels to face the west in addition to the south can reduce pressure on grid and enable solar power to satisfy a portion of peak afternoon demand. Image credit: NREL/Brothers Electric © 2008

POLICIES TO INCREASE DEPLOYMENT OF WEST-FACING SOLAR PV:

- State PUCs and/or state legislators can offer additional economic incentives for solar installations that are oriented towards the west.
- State legislatures can revise RPSs to mandate that regulated utilities obtain a certain percentage of power from west-facing solar installations.
- State PUCs can adopt a rebuttable presumption that utility investments in west-facing or east-west tracked solar PV installations are necessary and prudent, and thus eligible for cost recovery through ratemaking proceedings.
- State PUCs can adopt time-of-use electricity rates that provide added financial incentives for customers to offset their electricity consumption with solar power during peak demand periods.
- Local governments can adopt building mandates that require new or renovated buildings to install solar panels on west-facing roofs.

B. DEPLOY ADVANCED TECHNOLOGIES

To successfully integrate high levels of variable renewable energy onto the western grid without compromising reliability, policymakers can incentivize or require deployment of advanced technologies to stabilize variable loads, reduce grid congestion, and maximize existing transmission capacity. These advanced technologies include 1) non-variable renewable energy generation; 2) energy storage; and 3) smart grid and information technologies that facilitate demand response. The following subsections describe these technologies and briefly explore how deployment of these technologies can support grid reliability. Each subsection also suggests policies that could incentivize or mandate deployment of advanced energy and grid technologies.

1. NON-VARIABLE RENEWABLE ENERGY TECHNOLOGIES

States can support grid reliability while implementing the Clean Power Plan by deploying non-variable renewable resources in addition to variable renewables. Less-variable renewable resources, such as biogas, geothermal, and hydroelectric facilities, have the potential to provide predictable, stable generating outputs, and thus support grid reliability by minimizing unintentional fluctuations in generation.

The Clean Power Plan allows states to deploy generating resources fueled by qualified waste-derived biogenic feedstocks to reduce CO_2 emissions from affected EGUs.[258] Eligible feedstocks include biogas produced through anaerobic digestion of organic waste.[259] The preamble to the final rule states that EPA will likely approve waste-derived biogas as a "qualified" feedstock under a state plan because these fuels likely contribute minimal or no additional CO_2 emissions.[260] To qualify for emission reductions under the rule, the biogas-fired unit must be constructed after 2012.[261] In addition, the state plan must include additional biogas monitoring, reporting, and verification requirements to ensure that the feedstock will provide biogenic CO_2 benefits.[262]

Waste-derived biogas may present a promising renewable energy option under the Clean Power Plan, because the anaerobic digestion process helps to reduce methane emissions from organic waste. Methane is a potent greenhouse gas, and while methane emissions are not subject to emissions standards under the Clean Power Plan, reductions in methane emissions would compliment the rule's objective to reduce greenhouse gas emissions. Facilities such as wastewater treatment plants, dairies, and landfills typically vent or flare the byproduct biogas (which is largely comprised of methane) produced by the decomposition of organic waste.[263] Installing anaerobic digesters would enable these facilities to capture biogas emissions and use the gas to generate electricity.[264] Biogas generation tends to be fairly dispatchable, which supports grid reliability. And because anaerobic digesters can produce biogas from a wide variety of organic waste products, biogas facilities are not as geographically constrained as wind and solar resources.

Geothermal generating resources that are constructed after 2012 are also eligible for emission reduction credits under rate-based state plans, and geothermal generation may also reduce EGU emissions under mass-

Leathers Geothermal Power Plant, California. *Image credit: U.S. Department of Energy (2013)*

based plans.[265] Geothermal generation uses heat from the earth to create steam and generate electricity. Because the internal temperature of the earth is constant, geothermal facilities can provide consistent, non-variable generating outputs. Conventional geothermal generation provides baseload power for the grid, which allows these facilities to support grid reliability but not necessarily flexibility. However, a 2013 study by Aspen Environmental Group[266] found that modern geothermal plants are capable of ramping up and down very quickly, and thus can provide flexible generating output.[267] Geothermal resources therefore may help integrate variable renewable power while maintaining grid reliability and flexibility.

Small-scale hydroelectric facilities also have the potential to support grid reliability and balance variable renewable generation, and may contribute to emissions reductions under the final rule. Hydropower facilities generally provide baseload power, and many of these facilities can be cycled to provide flexible output to integrate variable renewable generation onto the grid.[268] However, large hydropower facilities can create significant environmental impacts for waterways and aquatic species, and western states are unlikely to approve the construction of any new high-capacity dams in the foreseeable future. Nevertheless, there are several promising hydropower designs that can support grid reliability and flexibility with minimal environmental impacts. For example, Lucid Energy of Portland, Oregon, recently installed hydropower turbines inside the city's water pipes.[269] Similarly, in-stream hydrokinetic generating units enable local waterways to generate hydropower with minimal environmental disruption.[270] The U.S. Department of Energy recognizes the potential of these emerging hydropower technologies; in April 2015, the Department announced $7 million in funding for "innovative technologies for low-impact hydropower systems."[271]

Non-variable renewable energy technologies, such as biogas, geothermal, and small-scale hydro generation, have the potential to help balance and integrate large amounts of variable renewable energy onto the grid without compromising reliability. Each of these technologies faces unique barriers to deployment that can be addressed through a variety of policies. While a full discussion of these policies is outside the scope of this report, the strategies listed below represent general policy options to promote deployment of non-variable renewable energy technologies.

A drop-in small-scale hydropower system in Oregon. *Image credit: Mark Riskedahl © 2014*

POLICIES TO FACILITATE DEVELOPMENT OF NON-VARIABLE RENEWABLE ENERGY SOURCES:

- State legislatures should revise RPSs to include biogas, geothermal, and small-scale hydro in the definition of eligible renewable resources.
- State legislatures can adopt RPS carve-outs that require a percentage of retail electricity sales to come from non-variable renewable resources.
- State governments can offer economic incentives, such as tax credits and cash rebates, for non-variable renewable energy development.
- State governments can offer production-based incentives or feed-in tariffs for non-variable renewable energy generation.
- State governments can offer low-interest loans for project development.
- State PUCs should revise integrated resource planning rules to require utilities to consider non-variable renewable resources as an alternative to new natural gas capacity and to comprehensively evaluate the long-term costs, benefits, and risks associated with these resource alternatives.
- State PUCs should adopt cost recovery policies that authorize utilities to recover costs and earn a rate of return on reasonable investments in non-variable renewable resources that may have higher costs than alternative fossil fuel-fired generation. For example, Colorado's Section 123 Resources initiative directs the state PUC to fully consider allowing a utility to rate base investments in alternative energy technologies that are not the least-cost resources, so long as the Commission determines the alternative technologies are "cost-effective."[272]

2. ENERGY STORAGE

Wide-scale deployment of energy storage capacity can also help grid operators balance variable renewable resources and maintain grid reliability under the Clean Power Plan. Energy storage can mitigate many of the reliability impacts presented by variable renewables by enabling grid operators to dispatch renewably generated power to satisfy peak consumer demand. Utility-scale energy storage technologies can reduce the need for new transmission capacity, and distributed storage systems can alleviate congestion on local distribution systems. In the preamble to the final rule, EPA stated that storage is useful but not essential for integrating variable renewable power onto the grid.[273] However, the preamble also notes that states can deploy energy storage to facilitate greater use of renewable energy.[274] In its *Initial Reliability Review* of the Clean Power Plan, NERC stated that "storage technologies support the reliability challenges that may be experienced when there is a large penetration of VERs [variable energy resources], and their development should be expedited."[275] While the west has substantial potential to expand the region's energy storage capacity, existing economic, regulatory, and technological barriers may constrain development of these systems.

Energy storage is conceptually quite simple—when renewable energy production exceeds consumer demand, the excess generation is "stored" in an energy storage device and then dispatched onto the grid when electricity demand exceeds available supply. From a practical standpoint, however, storing energy can be a highly complex and dynamic process. A variety of energy storage technologies are currently available or under development in the United States, including pumped hydro, batteries, flywheels, and compressed air energy storage systems. Outside of the United States, countries like Denmark are exploring innovative storage options that would store excess wind energy as heat through district heating systems. The cost, capacity, and storage characteristics of these technologies can vary significantly, and some technologies are more suitable for certain applications than others.

At present, pumped hydro (or pumped storage) is the most widely deployed energy storage technology in the United States; in 2011, it provided 22 of the 23 gigawatts of total installed storage capacity in the nation.[276] Today, the largest U.S. pumped storage facility can generate up to 3,000 megawatts of electricity, which is roughly equivalent to the output of three nuclear power plants.[277] A number of new closed-loop pumped storage facilities are in the early stages of development in the west, including two facilities in Montana,[278] a 600-megawatt facility in Oregon,[279] and a 1,200-megawatt facility in Washington state.[280] Pumped hydro has great potential for integrating variable renewable generation, because these facilities provide substantial storage capacities, are highly efficient, and offer both load-balancing and ancillary services for the grid.[281] However, pumped storage facilities are also expensive to construct, and it can take many years to obtain necessary permits and water rights.

A pumped storage generating station in Pennsylvania. *Image credit: U.S. Army Corps of Engineers*

Distributed energy storage is currently one of the fastest growing energy storage markets in the world. These systems typically pair a battery system with customer-sited distributed generation, such as a solar PV system. A 2015 report by Navigant Research projected that revenues from distributed energy storage systems will exceed $16.5 billion by 2023.[282] The rapid growth in distributed storage is primarily due to increased deployment of distributed generation systems. Distributed battery systems can support grid reliability by reducing peak electricity demands across a distribution system. Battery technologies and capacities have improved significantly in recent years, and system costs have decreased dramatically. However, residential-scale battery systems are still prohibitively expensive for many consumers.

Flywheels and compressed air energy storage are two emerging storage technologies that may help support grid reliability under the Clean Power Plan. Flywheel energy storage systems are now commercially available in the United States.[283] These systems support grid reliability and renewable energy integration by regulating and stabilizing frequency and voltage to balance short-term renewable intermittency.[284] Compressed air energy storage (CAES) is not as commercially available as other storage technologies, though a 110-megawatt CAES system in McIntosh, Alabama, has been operating commercially since 1991.[285] Grid operators and power generators are currently assessing the technological and economical feasibility of deploying compressed air energy storage to integrate intermittent renewable resources.[286]

District heating presents another emerging source of energy storage, though this technology has not been widely deployed in the United States. District heating systems use massive, centrally located boilers to heat water that is then distributed via a network of pipes into area houses and buildings.[287] Because shared boilers are much more efficient than distributed furnaces and hot water heaters, these systems have historically provided a source of energy efficiency rather than energy storage.[288] In Denmark, however, district heating systems are also used as energy storage systems.[289] District heating stations currently provide heat to 63% of Danish households.[290] In 2014, 39.1% of Denmark's total electricity generation came from wind energy,[291] and the country aims to produce 50% of its power from wind by 2025.[292] By 2035, the country aims to produce all electricity and heat from renewable resources, including wind energy.[293] To aid the country in integrating this amount of variable wind power, Denmark is exploring using heat pumps and the heat storage capacity in its district heating systems to store excess wind power.[294] Researchers estimated that Denmark could store between 20 and 30 gigawatt-hours of wind energy as useful heat, which would enable the country to integrate up to five gigawatts of wind capacity with minimal curtailment.[295] To achieve this level of storage capacity in the United States, communities would need to invest significant time and resources in developing district heating infrastructure. Nevertheless, district heating presents a system-level approach that could dramatically increase energy efficiency rates while facilitating the integration of variable renewable power onto the grid.

District heating pipes in Denmark transfer hot water and steam to consumers. *Image credit: Bill Ebbensen © 2008*

Energy storage technologies can support grid reliability and renewable integration at both the local and regional levels. However, a number of economic, regulatory, and technological barriers currently constrain the rate of energy storage deployment in the west.[296] In many instances, the capital costs of energy storage facilities are prohibitively high. Moreover, independent energy storage developers may lack access to energy price data or negotiated contract rates for energy storage services, which means that investor-owned utilities may be the only entities capable of accurately determining the value of storage facilities.[297] This creates a compounding barrier, because state utility regulators may not require utilities to assess the long-term costs and benefits of energy storage through their integrated resource planning processes. Absent this mandate, utilities may not be inclined to evaluate energy storage options due to overarching uncertainties related to the economics and performance of energy storage technologies.

Both grid-scale and distributed energy storage technologies have the potential to support grid reliability under the Clean Power Plan by enabling grid operators to integrate high levels of variable renewable generation onto the west's existing transmission and distribution systems. To support grid reliability under the Clean Power Plan, regulators should address barriers to deployment and adopt policies that incentivize energy storage development throughout the west.

POLICIES TO SUPPORT ENERGY STORAGE:

- State legislatures can adopt utility energy storage procurement mandates. For example, in 2013, the California PUC adopted an Energy Storage Procurement Framework and Design Program that directs the state's three investor-owned utilities to procure 1,325 megawatts of energy storage by 2020.[298]
- State and local governments can adopt economic incentive programs that provide financial incentives, such as cash rebates and tax credits, for investments in eligible energy storage systems, including customer-sited distributed storage.
- State and local governments can offer property tax exemptions for eligible energy storage systems.
- State PUCs should revise integrated resource planning rules to require utilities to evaluate energy storage as an alternative to additional generation or transmission resources, and to assess the long-term economic impacts that energy storage capacity will have on the utilities' existing resource portfolios.
- State PUCs should adopt cost recovery policies that authorize utilities to recover costs and earn a rate of return on reasonable investments in energy storage resources that may have higher costs than alternative fossil fuel-fired generation.[299]
- Local governments should explore district heating as a system-based strategy to increase energy efficiency and provide storage capacity for variable renewable power.
- Local and state governments should consider developing taxpayer-funded microgrids for critical public facilities and infrastructure, such as hospitals, fire stations, and emergency shelters that combine distributed renewable energy with energy storage.

3. DEMAND RESPONSE TECHNOLOGIES

Demand response programs encourage electricity consumers to shift or reduce their energy consumption during peak demand periods. Demand response can provide ancillary services for the grid by allowing grid operators to flexibly balance supply and demand with reduced reliance on peaking generating units. Smart grid technologies facilitate demand response by providing consumers with real-time information on their electricity rates and usage, or allowing utilities to directly control certain types of customer load during peak demand periods. Demand response programs and related smart grid investments can reduce electricity rates for participating consumers, and they have the potential to lower costs for all ratepayers by reducing the need for additional peaking generating units that only operate during periods of high demand. The Rocky Mountain Institute estimates that utility investments in "demand flexibility," which employs "smart" technologies to shift electricity use from peak to off-peak times of day, could avoid $9 billion per year in generation, transmission, and distribution costs.[300] Moreover, demand response measures that reduce output at affected EGUs can contribute towards compliance with rate-based or mass-based goals under the Clean Power Plan.[301]

Electricity providers can encourage consumers to alter their power usage patterns by offering time-of-use electricity rates, which charge higher rates for electricity consumed during peak hours. The California PUC recently voted to adopt time-of-use rates for the state's largest investor-owned utilities; the new rate structure will go into effect in 2019.[302] Utilities can also

"Smart" thermostats have the potential to provide cost-effective demand response services. *Image credit: Dennis Schroeder/NREL (2011)*

implement direct load control programs that allow them to control certain customer-sited appliances, such as hot water heaters or air conditioners, during peak hours.[303] Smart grid technologies, such as advanced electricity meters or in-home displays, further increase demand response potential by notifying consumers when peak rates are in effect and encouraging consumers to shift unnecessary energy consumption to off-peak periods. Similarly, smart home technologies, such as "smart" thermostats, can also provide demand response by enabling utilities to remotely adjust customer thermostat settings during peak demand periods. Utilities can also invest in web-based demand response software that alerts consumers when peak charges go into effect and encourages energy conservation.

Demand response programs are generally implemented at the utility level, and western utilities have adopted a variety of approaches to incentivize energy conservation during peak periods. Some utility programs notify participating consumers of the need to conserve energy during peak events and offer incentive payments for demand response efforts. For example, Idaho Power's Flex Peak program offers incentive rates for large commercial and industrial consumers that agree to reduce consumption within two hours' notice of a peak demand response event.[304] Other programs establish a price per unit of reduced consumption and allow consumers to participate on a voluntary basis. For example, PacifiCorp's Energy Exchange program is a web-based demand response bidding program in which the utility sets an upfront price for each hour of conservation needed, and consumers submit bids pledging to reduce consumption during the specified time period.[305] Finally, some programs give the utility the ability to directly control consumers' electricity usage. For example, the Public Service Company of New Mexico's Power Saver program offers consumers annual payments and an enrollment bonus for allowing the utility to connect a load control device to customers' air conditioning units.[306] In California, PG&E, SCE, and SDG&E operate an Automated Demand Response program that allows consumers to pre-program their preferred energy reductions, which the utilities then implement automatically during peak demand events.[307]

Smart home technologies also have the potential to increase demand response with minimal effort from consumers and electricity providers. For example, Commonwealth Edison (ComEd) launched an innovative demand response program that incentivizes customers to use "smart" thermostats that allow the utility to remotely adjust customers' thermostat settings during peak demand periods.[308] To implement the program, ComEd partnered with Nest Labs (developer of the Nest Learning Thermostat) and Comcast's Xfinity Home program.[309] While the program offers less reliability than demand response programs that give utilities direct control over customer appliances, it requires far less participation from ComEd itself.[310] For example, the utility does not have to install or operate any extra equipment in participants' homes, and Nest and Comcast are helping to market the program to customers. Overall, the program provides cost-savings for the utility and its customers and helps to reduce grid congestion during peak demand periods.

Demand response software also presents innovative demand response opportunities for utilities and consumers. Opower, an independent cloud-based utility software developer, has created an innovative demand response platform that draws on customers' behavioral patterns. The company asserts that its Behavioral Demand Response (BDR) platform has the potential to reduce peak demand by every one of a utility's residential customers.[311] According to the company's blog, BDR "uses high-resolution AMI data, rapid-fire analytics, behavioral science, and personalized communications to drive measurable peak reduction without a price signal or device in the home."[312] First, electricity customers receive emails from their utility asking them to reduce their electricity use during a period of high summer demand. If a customer reduces consumption during that period, the utility sends another email thanking the customer for conserving energy. This email also shows how much energy the customer conserved in relation to similar homes in the area, which encourages the customer to further reduce consumption during future demand response events.

Opower's 2014 behavioral response pilot project proved highly successful in encouraging consumers to reduce electricity use, without offering any financial incentives or imposing any penalties on non-compliant customers. Moreover, the platform could assist utilities in maintaining grid reliability under the Clean Power Plan while saving money for ratepayers. An interactive map on the company's website shows that the west's "behavioral energy potential" could free up 1,213.6 megawatts of capacity on the grid and avoid the need for 24 new peaking power plants.[313]

States (rather than the federal government) currently have jurisdiction to regulate incentive-based demand response programs,[314] and federal law encourages state regulatory authorities and non-regulated utilities to adopt demand response policies, such as time-based rates and advanced metering.[315] State utility regulators can thus establish reasonable retail electricity rates that incentivize reductions in electricity consumption, such as time-of-use rates. States can also adopt demand response programs that provide additional financial incentives for consumers to invest in demand response technologies or encourage utilities to procure a percentage of their peak generation through demand response.

POLICIES TO SUPPORT DEMAND RESPONSE:

- State legislatures can adopt demand response standards or targets that require utilities to obtain a percentage of their peak "generation" from demand response activities.
- State legislatures can establish ratepayer-funded demand response programs that offer financial incentives for smart grid investments, such as investments in demand response-enabled appliances.
- State PUCs can implement time-of-use electricity rates.
- State PUCs can direct jurisdictional utilities to implement behavioral demand response programs that encourage energy conservation during anticipated periods of high demand.
- State PUCs should ensure that ratemaking policies allow utilities to earn a sufficient rate of return on demand response and smart grid investments to offset revenue losses resulting from customer reductions in energy consumption.[316]
- State PUCs can revise rate recovery and integrated resource planning rules to require utilities to evaluate demand response potential and determine whether investments in smart grid and demand response technologies could offset the need for new generation.

C. COOPERATIVE AND MARKET-BASED APPROACHES

To further support grid reliability under the Clean Power Plan, policymakers should explore cooperative and market-based implementation strategies, such as interstate emission trading programs or an energy imbalance market, which may increase efficiency in the existing grid by providing real-time access to unused transmission capacity across the region. Western states can also help maintain grid reliability under the Clean Power Plan by coordinating implementation efforts and participating in a multi-state assessment of state plans. Regional cooperation has the potential to support interconnection-wide reliability by giving states the flexibility to develop individual implementation approaches that work in tandem with broader regional compliance strategies. The Clean Power Plan also gives states the option to engage in multi-state implementation programs, which could enable participating states to collectively achieve compliance with their emissions goals while reducing each state's implementation costs. The final rule gives states substantial flexibility in determining the appropriate scope of interstate implementation efforts. States that wish to submit individual plans yet still wish to participate in some interstate compliance activities can submit "ready for interstate trading" plans.[317] These plans give states the option to participate in interstate emissions trading programs without linking participants' compliance obligations to those of other states. The rule also enables states to submit formal multi-state implementation plans.[318] These plans establish a single joint emissions goal that aggregates participants' individual goals. All participating states are collectively responsible for achieving the joint emission goal. Regardless of whether states choose to implement the rule on an individual, collaborative, or multi-state basis, state regulators must consider how their compliance frameworks could impact the grid.

The following subsections discuss three cooperative or market-based approaches with the potential to support grid reliability under the Clean Power Plan: an interstate or regional emission trading program, an Energy Imbalance Market, and multi-state coordination and evaluation of state implementation plans. Each of these approaches requires multi-state collaboration, and thus cannot be achieved through unilateral policy reforms. Instead, western states should work together to establish cooperative programs that will enable participating states to efficiently implement the Clean Power Plan while maintaining grid reliability.

1. REGIONAL EMISSION TRADING PROGRAM

To help facilitate multi-state cooperation and coordinate state compliance approaches on a regional level, western states can participate in regional trading programs for emission reduction credits or emission allowances. Trading programs represent market-based approaches that can help support grid reliability while reducing compliance costs across the region. The Clean Power Plan encourages states to participate in interstate emission trading programs, which support grid reliability by providing affected EGUs with additional compliance flexibility and enabling participating states to reduce emissions as cost-effectively as possible.[319]

Under the final rule, states can trade emission credits or allowances with any other states following the same implementation approach.[320] For example, states implementing rate-based programs can trade with one another, and states implementing mass-based programs can trade with one another. States with rate-based plans can participate in interstate trading programs for emission reduction credits (ERCs), while states with mass-based plans can participate in interstate emission budget trading programs for emission allowances. These two types of trading programs are discussed in greater detail below.

States implementing either subcategory-specific emission performance rates or state-specific rate-based goals can participate in emission trading programs for ERCs. An ERC represents one megawatt-hour of zero-emitting generation or reduced electricity use.[321] States can issue ERCs to affected EGUs that reduce their emissions below the required performance rate, or for qualifying alternative measures that provide zero-emitting substitute generation.[322] Affected EGUs can then use any earned or purchased ERCs to adjust their reported emission rates by adding the number of ERC megawatt-hours to the denominator of their emission rates.[323]

To ensure that ERCs actually result in emission rate reductions that are quantifiable, verifiable, non-duplicative, permanent, and enforceable, ERC trading programs must comply with additional requirements under the Clean Power Plan. First, ERCs can only be issued for eligible measures and qualified projects or programs that reduce emission rates. Eligible measures include qualified, incremental grid-connected renewable energy or energy efficiency projects that became operational after 2012 and reduce emissions during a performance period.[324] Eligible measures also include demand-side management, efficiency upgrades to transmission and distribution systems, new nuclear power, and generation from non-affected combined heat and power and waste heat power units.[325] Qualified megawatt-hours must be independently quantified and verified.[326] Second, state plans must include provisions for tracking ERCs from issuance to submission for compliance, and this tracking program must require that each ERC be issued a unique identification number that enables it to be traced.[327] Third, state plans must establish additional evaluation, measurement and verification requirements for ERC projects.[328]

The Clean Power Plan allows states to obtain ERCs for measures implemented in other states, as long as those measures avoid emissions at an affected in-state EGU.[329] However, the rule imposes some restrictions on obtaining ERCs from emission reduction measures located in a state implementing a mass-based plan. States may create ERCs for qualified renewable energy generation within a mass-based state, but they must demonstrate that the renewable energy was actually delivered to the grid to meet electricity load in a state with a rate-based plan.[330] States cannot create ERCs for energy efficiency measures located in mass-based states.

States with mass-based plans can participate in emission budget trading programs for emission allowances. This type of trading program establishes a combined emission budget for a group of affected sources, which can then trade emission allowances representing one ton of avoided CO_2 emissions.[331] State plans following either type of mass-based plan approach (*i.e.* either a mass-based emission standard approach or a state measures approach) can participate in an emission budget trading program. Bilateral or multi-state trading programs may either allow states to use out-of-state allowances to meet their state-specific budgets, or establish an aggregate emission budget for all participating states.

The emission budget trading approach is more flexible than an ERC trading program, and state plans are not required to identify eligible measures or include additional quantification and verification requirements for emission reduction measures.[332] Measures that provide zero-emitting substitute generation or reduce electricity use are automatically accounted for through subsequent reductions in reported emissions from affected EGUs.[333] State plans must specify the emission budget and include emission monitoring, reporting, and recordkeeping requirements and provisions for allocating, tracking, and submitting allowances for compliance.[334] In addition, the mass-based standards must be quantifiable, verifiable, non-duplicative, permanent, and enforceable.

TABLE 5

CLEAN POWER PLAN EMISSION TRADING APPROACHES

PROGRAM	TRADING UNIT	ELIGIBLE MEASURES	ADDITIONAL REQUIREMENTS
RATE-BASED EMISSION REDUCTION CREDIT TRADING	• Tradable unit: Emission Reduction Credit (ERC) representing 1 megawatt-hour of zero-emitting generation or reduced electricity use • EGUs submit ERCs to adjust emission rates. Add ERC MWh to denominator of emission rate (i.e. lbs. CO_2/MWh)	• Qualified RE (wind, solar, geothermal, hydro, biomass, wave & tidal power) • Energy efficiency • Demand-side management • Transmission & distribution upgrades • New nuclear • CHP and WHP	• Measures must be installed after 2012 and reduce emissions between 2022–2030 • Only incremental capacity (post-2012) can adjust emission rates • Eligible measures must be grid tied • MWh must be quantified and verified
MASS-BASED EMISSION BUDGET TRADING	• Tradable unit: Emission allowance representing 1 ton of avoided CO_2 • State sets emission budget, allocates allowances to affected EGUs. EGUs must submit one allowance for each ton of CO_2 they emit.	• Any measures that reduce emissions at affected EGUs, including substitute generation from RE and reduced electricity use from energy efficiency • Under state measures approach, state can issue allowances for measures that offset EGU CO_2 emissions	Must address and mitigate emission leakage to new non-affected EGUs. • Regulate both existing and new EGUs using new source compliments to mass-based goals • Use output-based allocation methods to discourage shifts to new generation or set aside allowances for RE and/or energy efficiency

Mass-based emission budget trading gives states broad discretion and flexibility to achieve required emissions reductions as cost-effectively as possible. However, mass-based trading may also create an undesirable incentive to reduce emissions through deployment of new non-affected EGUs, which would result in emissions leakage. The Clean Power Plan therefore requires that emission budget trading programs address and mitigate potential leakage risks.[335] State plans can mitigate leakage by regulating non-affected EGUs in conjunction with affected EGUs, allocating emission allowances based on EGU generation levels, or creating allowance set-asides for incremental renewable energy or energy efficiency.[336] State plans can also demonstrate that due to the state's unique characteristics or plan design elements, leakage is not likely to occur.[337]

Under the Clean Power Plan, states have a few options for participating in interstate trading programs. First, states can submit "ready for interstate trading" plans to EPA that would allow the state to trade ERCs or allowances with other states using EPA approved or administered tracking programs.[338] This approach would not require the state plan to specifically identify other states participating in the trading program. Second, states can submit plans with trading programs linked to specific partner states.[339] These two options allow a state to submit an individual implementation plan that allows the state to retain its compliance goals. Third, states can submit joint multi-state plans that combine participating states' compliance obligations into a joint rate-based or mass-based goal. States with rate-based plans can also provide for joint ERC issuance with states implementing materially consistent trading programs and a shared tracking program.[340]

A regional emission trading program would facilitate Clean Power Plan compliance and encourage cost-effective renewable energy development throughout the west by allowing states with excess renewable generation to sell excess ERCs or emission allowances to states with limited renewable energy potential. In the preamble to the final Clean Power Plan, EPA stated that it views the emission budget trading program option as a particularly efficient market-based approach because it provides both short and long-term price signals that enable affected EGUs to identify the most cost-effective emission reduction strategies.[341] An emission budget trading program also allows states to implement more flexible emission reduction measures and implement different strategies over time without revising their state plans. Moreover, a regional emission budget trading program would allow western states to pursue collaborative compliance strategies without entering into a binding multi-state compliance plan. Participating states could establish their own individual emission budgets, and submit "ready for interstate trading" plans allowing individual EGUs to use out-of-state allowances to achieve emissions reductions.

A regional emission trading program could support grid reliability in the west by encouraging cost-effective renewable energy development in areas with optimal access to renewable resources and existing transmission infrastructure. A 2010 study by researchers at the Lawrence Berkeley National Laboratory (LBNL) found that regional renewable energy credit (REC) trading could greatly reduce the need for long-distance transmission associated with increased renewable energy deployment in the west.[342] The LBNL study found that widespread REC trading could reduce the transmission costs associated with a 33% renewable energy target by between $5 billion to $17 billion.[343] A regional emission trading market could similarly reduce compliance costs and support grid reliability by freeing up transmission capacity and reducing the need for additional transmission development.

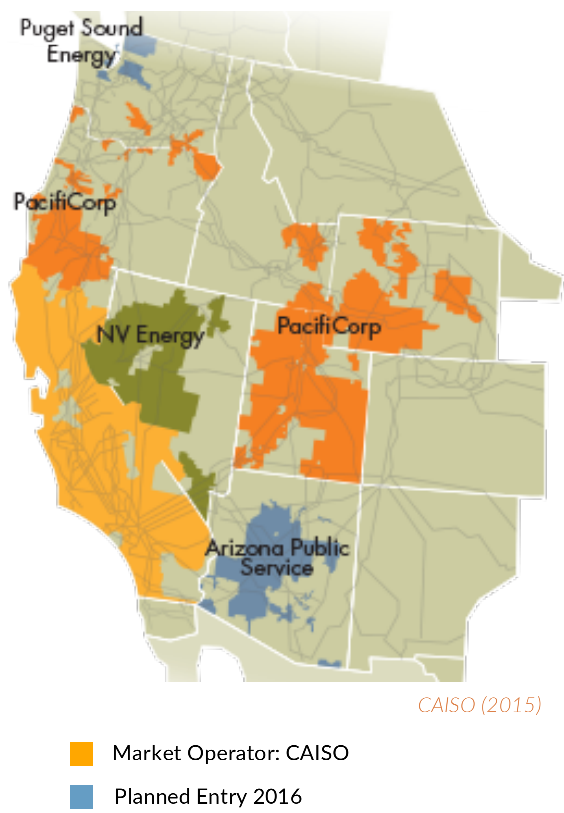
A regional emissions trading program would further support grid reliability by granting states flexibility to adjust compliance activities and respond to reliability constraints on a regional basis. An interstate trading market would also reduce the potential for reliability emergencies that would otherwise trigger the rule's reliability safety valve. To maintain reliability and promote compliance flexibility, western state regulators should collaborate throughout the plan development stage to ensure that individual state plans facilitate interstate or regional emission trading.

2. ENERGY IMBALANCE MARKET

To facilitate the integration of high penetrations of variable renewable resources under the Clean Power Plan, western states, utilities, and balancing areas could consider establishing an interconnection-wide Energy Imbalance Market, or EIM. An EIM is a sub-hourly energy marketplace that allows generators to sell power and transmission owners to sell capacity in short-term intervals to stabilize imbalances of supply and demand on the grid. An interconnection-wide EIM could support grid reliability by enabling grid operators to efficiently manage congestion or supply shortfalls across multiple balancing areas. An EIM could also mitigate capacity constraints within the existing grid and may reduce the need for additional transmission capacity across the west. However, an EIM could also introduce additional complexities and costs into the existing system, and would require significant cooperation between participants to minimize the potential for market manipulation or abuse. State policymakers, grid operators, and power producers should therefore carefully evaluate the potential risks and benefits before making any final decisions to promote or participate in an EIM.

A centralized energy imbalance market would supplement, rather than supersede, the existing transactional model that western utilities follow today. Under the current system, renewable energy generators enter into power purchase agreements with distribution utilities and then purchase and schedule transmission services to deliver their power output to end users. As the discussion on sub-hourly scheduling noted,[344] a generator's actual output does not always equal its scheduled output, which can contribute to imbalance on the system. An EIM would enable grid operators to correct these imbalances by dispatching the least-cost generation bid into the market in five-minute intervals.[345] Participation in the

CALIFORNIA ISO EIM FOOTPRINT



CAISO (2015)

EIM would be voluntary, and power producers would not be obligated to sell their output through the marketplace. Instead, generators would have the option to sell their excess output or capacity through the EIM.

An interconnection-wide EIM could enable western states to integrate higher levels of variable renewable generation onto the grid while maintaining reliability and mitigating transmission capacity constraints. The EIM could support grid reliability by enabling balancing authorities to coordinate and correct imbalances by dispatching resources from across the region.[346] Grid operators would be able to determine the amount of available transmission capacity based on real-time power flows within the system, which would alleviate transmission congestion and maximize existing transmission capacity.[347] An EIM could also reduce the need for expensive reserve resources, because generation imbalances would be corrected through market purchases rather than localized reserve generation.

The California Independent System Operator (ISO) and PacifiCorp launched an EIM in November 2014, which allows other western balancing authorities to participate in the ISO's existing real-time energy market.[348] NV Energy, Puget Sound Energy, and Arizona Public Service are joining the California EIM as well.[349] With these additions, the EIM will extend to 35.3 million customers across eight western states.[350] The EIM automatically balances supply and demand across the system in 15-minute intervals and dispatches the least-cost resources available every five minutes.[351]

The Northwest Power Pool (NWPP) is currently assessing the potential for establishing an EIM among its member balancing authorities.[352] Many energy sector stakeholders view an EIM as the most promising solution for integrating large amounts of variable renewable generation onto the grid.[353] Some stakeholders, however, are concerned that an EIM could introduce additional complexity, cost, and potential for abuse and manipulation into the current system.[354] Moreover, additional risks may emerge if western states implement multiple EIMs. If parallel EIMs fail to seamlessly structure their markets to enable cross-participation, market inefficiencies will arise that prevent loads and renewable resources in one market from participating in another market.

Implementing a western interconnection-wide EIM would require significant cooperation and collaboration between state regulators, balancing authorities, and utilities. Participants would need to establish an independent entity to manage the energy imbalance transactions and monitor the system to prevent market manipulation. The Northwest Power Pool Market Assessment and Coordination Committee has been carefully evaluating the potential costs, benefits, and feasibility of implementing an EIM in the Northwest, and it expects to reach a decision on whether to pursue such a program in late 2015.[355] Regulators and grid operators should review the Committee's findings and consider the potential for expanding a sub-regional market into an interconnection-wide program.

Utilities that choose not to participate in an EIM may still benefit from participating in smaller-scale joint dispatch agreements. For example, three Colorado utilities—Black Hills Colorado, Platte River Authority, and Public Service Co. of Colorado—entered into a Joint Dispatch Agreement (JDA) that enables the utilizes to pool their generating resources and dispatch the most efficient units to satisfy demand.[356] The JDA resembles an EIM in structure and allows the participating utilities to dispatch their resources in real-time through a centralized, coordinated system.[357] Similarly to an EIM, the JDA may enable the utilities to integrate variable renewable resources onto the grid by giving the participants access to a broader group of resources. However, the program does not benefit from the level of geographical diversity that an interconnection-wide EIM would promote.

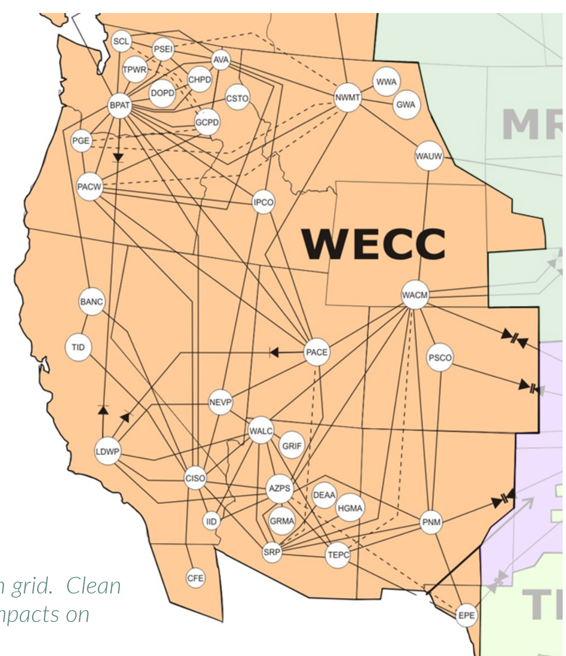
An interconnection-wide EIM has the potential to support reliability under the Clean Power Plan by stabilizing real-time imbalances between supply and demand across the grid. In the preamble to the final rule, EPA noted that an EIM entails increased regional coordination, which may increase the flexibility and efficiency of the power system.[358] However, a regional marketplace may also be difficult and costly to implement, and it may introduce new opportunities for manipulation into the electricity market. State policymakers, grid operators, and power producers should therefore carefully evaluate the potential risks and benefits of an EIM to determine whether this type of market could be advantageous on a regional scale.

3. MULTI-STATE COORDINATION AND EVALUATION OF STATE IMPLEMENTATION PLANS

The Clean Power Plan gives states flexibility to develop both individualized and collaborative compliance strategies to meet emissions reduction requirements. While this flexibility enables states to mitigate negative impacts to their own power sectors, individualized implementation approaches may aggravate grid reliability issues on a multi-state or regional level. For example, if one state's implementation plan calls for retiring a coal plant that primarily generates power for export to a neighboring state, and the neighboring state's implementation plan relies on importing the output from the coal plant, the two plans will conflict with one another and potentially impact grid reliability. If a number of state implementation plans conflict across the region, the reliability of the entire western interconnection could be compromised. To prevent this outcome, states must collaborate with one another during the planning process to ensure that individualized compliance approaches will not compromise the reliability of the regional grid. If multiple states decide to participate in a joint implementation plan or interstate emission trading, these states must assess how this multi-state plan will interact with non-participating state compliance efforts.

In the preamble to the final Clean Power Plan, EPA stated that "[r]egional cooperation in planning and reliability assessments is an important tool to meeting system needs in the most cost-effective, efficient, and reliable way."[359] WECC also supports regional coordination of state implementation plans. In its preliminary assessment of the draft Clean Power Plan, WECC emphasized the

BALANCING AUTHORITIES AND TRANSMISSION PATHWAYS IN THE WECC REGION



The map at right illustrates the interconnectedness of the western grid. Clean Power Plan implementation in one state could have substantial impacts on balancing authorities in states throughout the region.

U.S. Energy Information Administration (2014)

WESTERN TRANSMISSION PLANNING REGIONS

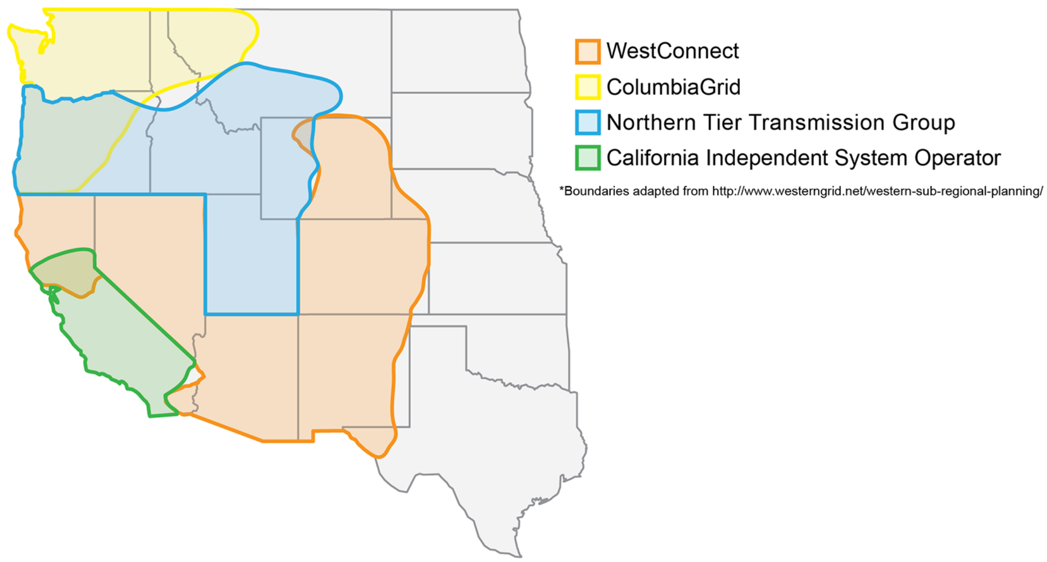


Image credit: OpenEI

importance of evaluating state implementation plans at the multi-state or regional level. WECC recommended that states jointly evaluate proposed implementation plans to "(1) ensure that individual and/or regional state plans achieve their intended goals and do not unintentionally impact one another; and (2) allow for a thorough investigation into any potential reliability impacts that may not be apparent when looking at plans on an individual basis."[360] WECC also noted that a comprehensive, interconnection-wide assessment of proposed implementation plans would be valuable in determining how the cumulative effects of multiple compliance actions would impact the interconnected grid system.[361] The final rule similarly recognizes the value of assessing the regional implications of individual state plans, and encourages states to consult with relevant regional planning authorities during the plan development stage.[362]

To maintain reliability across the grid, states should strive to coordinate their implementation plans with other states in the region as much as practicable. During the planning process, state regulators from across the west should collaborate closely with one another to ensure that state implementation plans are compatible on a regional scale. If states choose to enter into multi-state plans, they should evaluate how these plans will interact with plans from non-participating states in the region. Both individual and multi-state implementation plans should be evaluated for reliability and system impacts at multiple levels, including by balancing authorities, regional transmission planning organizations (including ColumbiaGrid, the Northern Tier Transmission Group, and WestConnect), and subregional reliability organizations (such as the Northwest Power Pool). Finally, WECC should conduct a comprehensive interconnection-wide assessment of individual and multi-state plans to ensure that changes in the resource mixes and load forecasts in the different planning regions will not threaten operations in the western interconnection as a whole.

CONCLUSION

Implementing the Clean Power Plan in the west will present a number of challenges for the grid, yet the rule also presents an opportunity to modernize and optimize the grid to accommodate increased deployment of sustainable energy resources. Western states can effectively integrate high levels of renewable energy onto the grid without compromising reliability by optimizing grid operations, deploying advanced technologies, and implementing cooperative and market-based mechanisms to facilitate efficient regional compliance.

To effectively implement these strategies, state, regional, and federal decision makers will need to adopt and implement policies to make the grid more flexible, resilient, and reliable. Policymakers can offer financial incentives to encourage grid operators, power generators, and electricity consumers to invest in technologies and practices that support grid reliability. Policymakers can also adopt mandates that direct utilities and transmission providers to deploy advanced resources, technologies, and operational practices that facilitate the integration of additional variable renewable capacity onto the grid without compromising reliability. In addition, policymakers can revise existing laws and regulations to increase coordination between local, state, and regional regulatory entities and enable balancing authorities to better integrate variable output on a regional basis. Finally, policymakers can consider adopting or expanding market-based or cooperative programs that may enhance grid reliability across the region.

The western grid is a highly interconnected system, and shifts in one state's resource mix may cause reliability issues in other states. Therefore, if states choose to adopt an isolationist approach to Clean Power Plan implementation, the entire grid may suffer. Instead, western states should work together in a cooperative, collaborative manner to preemptively address inevitable changes in the western resource mix. In doing so, states should strategically invest in generating resources, technologies, and operational practices that strengthen the western grid as a whole and facilitate the transition to a clean, renewable energy sector.

END NOTES

[1] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (August 3, 2015) (to be codified at 40 C.F.R. pt. 60) [hereinafter Clean Power Plan].
[2] *Id.* at 16.
[3] CAA § 111(b)(1)(A).
[4] CAA § 111(b)(1)(B).
[5] CAA § 111(d)(1).
[6] 40 C.F.R. § 60.22.
[7] 40 C.F.R. § 60.24.
[8] Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act, 74 Fed. Reg. 66,496, 66,497 (Dec. 15, 2009) (codified at 40 C.F.R. ch. I).
[9] Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, Notice of Proposed Rulemaking, 79 Fed. Reg. 1,432 (Jan. 8, 2014).
[10] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 FED. REG. 34,830 (June 18, 2014).
[11] Clean Power Plan, *supra* note 1, at 14.
[12] The rule specifically applies to fossil fuel-fired electric utility steam generating units and stationary combustion turbines. *Id.* at 28.
[13] *Id.* at 775.
[14] *Id.* at 9.
[15] *Id.* at 27.
[16] *Id.* at 28.
[17] *Id.* at 22.
[18] *Id.* at 28–29.
[19] *Id.* at 841–843, table 12.
[20] *Id.*
[21] *Id.* at 29–30.
[22] *Id.* at 17.
[23] *Id.* at 32–33.
[24] *Id.* at 884.
[25] *Id.* at 884–885.
[26] *Id.* at 885.
[27] *Id.* at 898.
[28] *Id.* at 899.
[29] *Id.* at 852.
[30] *Id.* at 37.
[31] *Id.* at 900.
[32] *Id.* at 889.
[33] *Id.* at 894.
[34] *Id.* at 876.
[35] *Id.* at 74–75.
[36] *Id.* at 917–18.
[37] *Id.* at 915.
[38] *Id.*
[39] *Id.* at 1,008.
[40] *Id.* at 945–46.
[41] *Id.* at 958–59.

[42] *Id.* at 963–64.
[43] *Id.* at 968–69.
[44] *Id.* at 1,110.
[45] *Id*.
[46] *Id.* at 1,112.
[47] *Id.* at 1,113.
[48] *Id.*
[49] *Id.*
[50] The Federal Power Act granted FERC exclusive jurisdiction over the rates, terms, and conditions associated with the transmission and sale of power in interstate commerce. Federal Power Act §§ 201, 205, 206, codified at 16 U.S.C. §§ 824, 824d, 824e (2015).
[51] FERC's Order 888 mandated that all public utilities that own or operate transmission facilities must "functionally unbundle" their wholesale transmission functions from their merchant functions, which means that one corporate division manages the utilities' power sales, and a separate corporate division manages the utilities' transmission services. Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services By Public Utilities, Order 888, 75 FERC 61,080 (Apr. 24, 1996), *codified at* 18 C.F.R. pts. 35, 385 [hereinafter FERC Order 888].
[52] 2005 Energy Policy Act, Pub. L. No. 109-58, 119 Stat. 594.
[53] 16 U.S.C. § 824o (2015).
[54] FERC, *NERC Certified as Electric Reliability Organization*, July 20, 2006, http://www.ferc.gov/media/news-releases/2006/2006-3/07-20-06-E-5.asp.
[55] North American Electric Reliability Corporation, www.nerc.com; 16 U.S.C. § 824o (2015).
[56] 16 U.S.C. §§ 824o, 825o-1 (2015).
[57] The western interconnection actually passes through 14 states, including small portions of South Dakota, Nebraska, and Texas. This report focuses on the 11 states that are fully integrated within the western grid. These are Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming.
[58] NERC, POTENTIAL RELIABILITY IMPACTS OF EPA'S PROPOSED CLEAN POWER PLAN: PHASE I (2015), *available at* http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Potential%20Reliability%20Impacts%20of%20EPA's%20Proposed%20Clean%20Power%20Plan%20-%20Phase%20I.pdf [hereinafter NERC PHASE I REPORT].
[59] Western Electricity Coordinating Council, *WECC 101*, https://www.wecc.biz/Pages/101.aspx#/WECC.
[60] *See* Peak Reliability, *Peak's History*, https://www.peakrc.com/aboutus/Pages/History.aspx.
[61] See NERC's definition of "regional reliability organization." NERC, GLOSSARY OF TERMS USED IN NERC RELIABILITY STANDARDS 69 (2015), *available at* http://www.nerc.com/files/glossary_of_terms.pdf [hereinafter NERC Glossary].
[62] See NERC's definition of "reliability coordinator." *Id.* at 71; NERC Reliability Standard IRO-001-1.1, Reliability Coordination—Responsibilities and Authorities (2009).
[63] California ISO, http://www.caiso.com/Pages/default.aspx.
[64] Western Electricity Coordinating Council, http://westernenergyboard.org/reliability/western-electricity-coordinating-council-wecc/.
[65] *See* WECC, *Western Interconnection Balancing Authorities Map*, https://www.wecc.biz/Administrative/WECC_BAMap.pdf.
[66] *See* REGULATORY ASSISTANCE PROJECT, ELECTRICITY REGULATION IN THE U.S.: A GUIDE 9 (2011), *available at* https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&ved=0CB8QFjAA&url=http%3A%2F%2Fwww.raponline.org%2Fdocs%2FRAP_Lazar_ElectricityRegulationInTheUS_Guide_2011_03.pdf&ei=CflDVfbwC4ftoASMi4HgCQ&usg=AFQjCNGQmJpx6o94LjxdGMzSmrsBiezsFQ&bvm=bv.92291466,d.cGU.
[67] WECC, EPA CLEAN POWER PLAN: PHASE 1—PRELIMINARY TECHNICAL REPORT at 12, fig. 3 (2014), available at https://www.wecc.biz/Reliability/140912_EPA-111(d)_PhaseI_Tech-Final.pdf [hereinafter WECC CPP Report].
[68] U.S. Energy Info. Admin., *Wyoming: State Profile and Energy Estimates* (Aug. 21, 2014), http://www.eia.gov/state/?sid=WY#tabs-4.
[69] EPA, Clean Power Plan State at a Glance: Wyoming (Aug. 2015), *available at* http://www.epa.gov/airquality/cpptoolbox/wyoming.pdf.
[70] EPA, Clean Power Plan State at a Glance: Washington (Aug. 2015), *available at* http://www.epa.gov/airquality/cpptoolbox/washington.pdf. Washington is permitted to increase its emissions

because its 2012 baseline is not representative of a typical year of generation; hydropower provides most of the state's electricity, and 2012 was a high-water year in the Pacific Northwest, which contributed to above-average hydropower output. *See* State of Washington, Comments on the Clean Power Plan Proposed Rule for Existing Power Plants 2–3 (Dec. 1, 2014), *available at* http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0602-22764.
[71] E&E Publishing Power Plan Hub, *Montana*, Aug. 6, 2015, http://www.eenews.net/interactive/clean_power_plan/states/montana.
[72] E&E Publishing Power Plan Hub, *Idaho*, Aug. 6, 2015, http://www.eenews.net/interactive/clean_power_plan/states/idaho.
[73] WECC CPP Report, *supra* note 67, at 15
[74] *Id.* at 13, 16. These projections are based on known and announced retirements.
[75] Clean Power Plan, *supra* note 1, at 661.
[76] The Wyoming PUC, for example, believes that the state's coal fleet can realistically meet an average heat rate of 2%. Wyoming Pub. Service Comm'n, Comments on Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, Docket ID No. EPA-HQ-OAR-2013-0602 at 1–2 (Nov. 21, 2014), *available at* http://psc.state.wy.us/pscdocs/dwnload/ChairmansLetter-GinaMcCarthy.pdf.
[77] WECC CPP Report, *supra* note 67, at 15–16.
[78] WECC CPP Report, *supra* note 67, at 16–17.
[79] Clean Power Plan, *supra* note 1, at 688.
[80] The preamble to the final rule states that "[s]ubstantial shifting of generation from affected EGUs to new fossil fuel-fired EGUs, such as new NGCC units, represents a deviation from implementing the BSER or its compliance equivalent." *Id.* at 825.
[81] States submitting mass-based plans must include provisions to address emissions leakage resulting from a shift to new NGCC units. *Id.* at 826. EPA determined that states implementing the rate-based emission goals are unlikely to incentivize substantial shifts from existing generation to new NGCC generation. *Id.* at 825–26.
[82] WECC CPP Report, *supra* note 67, at 29–30.
[83] Clean Power Plan, *supra* note 1, at 750.
[84] *Id.* at 752.
[85] *Id.* at 760–61, table 10.
[86] *Id.* at 752.
[87] Envt'l Protection Agency, Technical Support Document: GHG Abatement Measures, Data File: Proposed Renewable Energy (RE) Approach (2014), *available at* http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents.
[88] Clean Power Plan, *supra* note 1, at 760.
[89] WECC, 2022 PC1 COMMON CASE 30 (2011), *available at* https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=2&ved=0CCQQFjAB&url=https%3A%2F%2Fwww.wecc.biz%2FReliability%2F2022PC1_Common_Case_StudyReport_2011SP.docx&ei=HjJBVYLBMpD2oASr54DwAg&usg=AFQjCNEo83-Ady0A3SHw6GS1zCdbCaYowg&bvm=bv.92189499,d.cGU [hereinafter WECC COMMON CASE].
[90] Clean Power Plan, *supra* note 1, at 876.
[91] The WREZ Initiative's overarching objective was to facilitate development of utility-scale renewable energy facilities and necessary transmission infrastructure to deliver energy from these areas throughout the western interconnection, which included the Canadian portion of the grid. WESTERN RENEWABLE ENERGY ZONES—PHASE 1 REPORT 2 (2009), *available at* http://www.csg.org/programs/policyprograms/ncic/documents/WREZ091.pdf [hereinafter WREZ PHASE 1].
[92] *Id.* at 11–12.
[93] RYAN PLETKA & JOSH FINN, WESTERN RENEWABLE ENERGY ZONES, PHASE 1: QRA IDENTIFICATION TECHNICAL REPORT 2-5 (2009), *available at* http://www.nrel.gov/docs/fy10osti/46877.pdf.
[94] WECC's 2022 Common Case projected that the region's total generating capacity in 2022 will exceed 240,000 MW, and NREL and the Western Governors' Association identified more than 200,000 MW of potential renewable capacity in the region. See WECC COMMON CASE, *supra* note 89, at 39; WREZ PHASE 1, *supra* note 91, at 2.
[95] NAT'L RENEWABLE ENERGY LAB., RENEWABLE ELECTRICITY FUTURES STUDY (2012), *available at* http://www.nrel.gov/analysis/re_futures/ [hereinafter NREL RENEWABLE FUTURES].

[96] NERC, POTENTIAL RELIABILITY IMPACTS OF EPA'S PROPOSED CLEAN POWER PLAN: INITIAL RELIABILITY REVIEW (2014), *available at* http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Potential_Reliability_Impacts_of_EPA_Proposed_CPP_Final.pdf [hereinafter NERC INITIAL RELIABILITY REVIEW]; NERC PHASE I REPORT, *supra* note 58.
[97] NERC INITIAL RELIABILITY REVIEW, *supra* note 96.
[98] *Id.* at 2.
[99] Pursuant to section 215 of the Federal Power Act, NERC develops mandatory and enforceable reliability standards for the U.S. power grid. NERC, *United States Mandatory Standards Subject to Enforcement,* http://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United%20States.
[100] KEVIN COFFEE, ET AL., DYNAMIC TRANSFERS: DYNAMIC TRANSFERS FOR RENEWABLE ENERGY IN THE WESTERN INTERCONNECTION, WESTERN RENEWABLE ENERGY ZONES INITIATIVE—PHASE III, at 34–35 (2013), *available at* http://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&ved=0CB8QFjAA&url=http%3A%2F%2Fwww.raponline.org%2Fdocument%2Fdownload%2Fid%2F6603&ei=1wX1VPvaOsPwoASPvIAQ&usg=AFQjCNGzzgRw7_JxsbnZV6dStJKJMMPIog&bvm=bv.87269000,d.cGU [hereinafter WREZ Dynamic Transfers].
[101] *Id.* at 7.
[102] NERC Glossary, *supra* note 61, at 5.
[103] *See* DHRUV BHATNAGAR, ET AL., SANDIA NAT'L LAB., MARKET AND POLICY BARRIERS TO ENERGY STORAGE DEPLOYMENT: A STUDY FOR THE ENERGY STORAGE SYSTEMS PROGRAM 16 (2013), *available at* http://www.sandia.gov/ess/publications/SAND2013-7606.pdf.
[104] NERC, ESSENTIAL RELIABILITY SERVICES TASK FORCE, DRAFT CONCEPT PAPER ON ESSENTIAL RELIABILITY SERVICES THAT CHARACTERIZE BULK POWER SYSTEM RELIABILITY iv (2014), *available at* http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF_Draft_Concept_Paper_Sep_2014_Final.pdf [hereinafter NERC ERS CONCEPT PAPER].
[105] NERC PHASE I REPORT, *supra* note 58, at 29.
[106] WECC CPP Report, *supra* note 67, at 18.
[107] NERC ERS CONCEPT PAPER, *supra* note 104, at 1.
[108] WECC CPP Report, *supra* note 67, at 20; NERC Glossary, *supra* note 61, at 38.
[109] NERC ERS CONCEPT PAPER, *supra* note 104, at 1.
[110] WECC CPP Report, *supra* note 67, at 18.
[111] *Id.*
[112] SUSAN TIERNEY , ET AL., ELECTRIC SYSTEM RELIABILITY AND EPA'S CLEAN POWER PLAN: TOOLS AND PRACTICES 22, n. 40 (2015), *available at* http://www.analysisgroup.com/uploadedFiles/Publishing/Articles/Electric_System_Reliability_and_EPAs_Clean_Power_Plan.pdf.
[113] WECC CPP Report, *supra* note 67, at 20.
[114] *See* NERC INITIAL RELIABILITY REVIEW, *supra* note 96, at 25.
[115] WECC CPP Report, *supra* note 67, at 18.
[116] NERC ERS CONCEPT PAPER, *supra* note 104, at 6.
[117] D. LEW, ET AL., THE WESTERN WIND AND SOLAR INTEGRATION STUDY PHASE 2 xi (2013), *available at* http://www.nrel.gov/docs/fy13osti/55588.pdf [hereinafter NREL WWSIS Phase 2].
[118] *Id.*
[119] NERC INITIAL RELIABILITY REVIEW, *supra* note 96, at 25.
[120] *Id*. at 13.
[121] NREL WWSIS Phase 2, *supra* note 117, at xi.
[122] *Id.*
[123] *Id.*
[124] NERC INITIAL RELIABILITY REVIEW, *supra* note 96, at 13.
[125] *Id*.
Operating reserves provide additional generation in response to increases in load over extended time periods or following a contingency event. NERC ERS CONCEPT PAPER, *supra* note 104, at 2.
[126] Clean Power Plan, *supra* note 1, at 1,117.
[127] *Id.* at 1,117–18.
[128] *Id.* at 1,118–19.

[129] *Id.* at 1,119.
[130] *Id.*
[131] *Id.* at 1,120.
[132] *Id.*
[133] *Id.*
[134] *Id.*
[135] *Id.* at 1,113.
[136] *Id.* at 1,069.
[137] *Id.*
[138] *Id.* at 1,122–23.
[139] *Id.* at 1,123.
[140] *Id.* at 1,125.
[141] *Id.*
[142] *Id.*
[143] *Id.* at 1,126.
[144] *Id.* at 1,130.
[145] *Id.*
[146] *Id.* at 1,108–09.
[147] *Id.* at 764.
[148] NREL RENEWABLE FUTURES, *supra* note 95, at iii.
[149] *See* Jean Chemnick, *Power Rule Won't Harm Grid Reliability – McCarthy*, E&E NEWS, April 23, 2015, http://www.eenews.net/eenewspm/2015/04/23/stories/1060017347.
[150] Clean Power Plan, *supra* note 1, at 1,115–16.
[151] *See* KEVIN PORTER, ET AL., MEETING RENEWABLE ENERGY TARGETS IN THE WEST AT LEAST COST: THE INTEGRATION CHALLENGE 42, 54–55 (2012), *available at* http://www.raponline.org/featured-work/meeting-renewable-energy-targets-in-the-west-at-least-cost-the-integration.
[152] *See* U.S. Dept. of Energy, *Wind Resource Assessment and Characterization,* ENERGY.GOV, http://energy.gov/eere/wind/wind-resource-assessment-and-characterization.
[153] PORTER, ET AL., *supra* note 151, at 63.
[154] WREZ PHASE 1, *supra* note 91, at 8
[155] *Id.*
[156] The WREZ initiative identified a total of 54 hubs, but 16 of these hubs are located in the Canadian and Mexican portions of the western interconnection. *Id.* at 12.
[157] *See* map, WREZ PHASE 1, *supra* note 91, at 12.
[158] PORTER, ET AL., *supra* note 151, at 64.
[159] *See* LISA SCHWARTZ, RENEWABLE RESOURCES AND TRANSMISSION IN THE WEST: INTERVIEWS ON THE WESTERN RENEWABLE ENERGY ZONES INITIATIVE (2012), *available at* http://www.raponline.org/featured-work/meeting-transmission-needs-in-western-states.
[160] *See id.* at 67.
[161] Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Order 1000, 136 FERC ¶ 61,051 (July 21, 2011), *codified at* 18 C.F.R. Part 35.
[162] To mitigate the risk of legal challenge, REC multipliers should apply to projects constructed in any identified WREZ hubs throughout the west, and should avoid limiting eligibility to in-state projects.
[163] PUC interconnection rules only apply to projects that will sell output directly to a retail distribution utility (such as an investor-owned utility); if a project intends to sell power elsewhere and needs to interconnect with and "wheel" power over utility- or federal power authority-owned transmission lines, the project will fall under FERC jurisdiction. *See, e.g.,* Or. Pub. Utilities Comm'n, Small Generator Interconnection Rules, OAR 860-082-0005(1) (2015); FERC, Small Generator Interconnection Procedures, App. C (rev. Sept. 19, 2014), *available at* http://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp.
[164] PORTER, ET AL., *supra* note 80, at 42.
[165] *Id.*

[166] JURGEN WEISS, PHD, & BRUCE TSUCHIDA, INTEGRATING RENEWABLE ENERGY INTO THE ELECTRICITY GRID 22 (2015), *available at* http://info.aee.net/hubfs/EPA/AEEI-Renewables-Grid-Integration-Case-Studies.pdf?t=1433889350702.
[167] Xcel Energy, *Colorado Wind Power,* http://www.xcelenergy.com/Environment/Renewable_Energy/Wind/Colorado_Wind_Power.
[168] *Id.*
[169] AtmosNews, *NCAR Wind Forecasts Save Millions of Dollars for Xcel Energy,* Nov. 10, 2011, https://www2.ucar.edu/atmosnews/news/5771/ncar-wind-forecasts-save-millions-dollars-xcel-energy.
[170] *Id.*
[171] Xcel Energy, *Colorado Wind Power,* http://www.xcelenergy.com/Environment/Renewable_Energy/Wind/Colorado_Wind_Power.
[172] U.S. DEPT. OF ENERGY, NEW FORECASTING TOOLS ENHANCE WIND ENERGY INTEGRATION IN IDAHO AND OREGON 2 (2014), *available at* https://www.smartgrid.gov/sites/default/files/doc/files/C5-Idaho-Power-final-draft-091914.pdf.
[173] *Id.* at 1.
[174] *Id.*
[175] *Id.*
[176] *Id.* at 2.
[177] Power producers and grid operators are already required to share some information with one another. For example, FERC Order 764 amends large generator interconnection agreement and directs VER generators to provide meteorological and forced outage data to grid operator so they can develop and deploy power production forecasting. Integration of Variable Energy Resources, 139 FERC ¶ 61,246 (2012) [hereinafter FERC Order 764].
[178] KEN DRAGOON, SMALL RESOURCE TRANSMISSION SCHEDULING: SPECIAL CHALLENGES FACING SMALLER GENERATORS 8 (2014).
[179] FERC Order 764, *supra* note 177, at 3–4.
[180] *See* FERC Order 764, *supra* note 177; *see* Idaho Power Company, Idaho Power Transmission Business Practices, *Section 25—Intra-hour Transmission Service Requests and Scheduling* (Nov. 12, 2013), *available at* http://www.oasis.oati.com/IPCO/IPCOdocs/IPC_BP_FINAL_Section_25_Intra-hour_Transmission_Service_Requests_and_Scheduling_v1_11-12-2013.pdf.
[181] *See* Idaho Power Company, Idaho Power Transmission Business Practices, *Section 25—Intra-hour Transmission Service Requests and Scheduling* (Nov. 12, 2013), *available at* http://www.oasis.oati.com/IPCO/IPCOdocs/IPC_BP_FINAL_Section_25_Intra-hour_Transmission_Service_Requests_and_Scheduling_v1_11-12-2013.pdf.
[182] *See discussion infra*.
[183] For example, both PGE and PacifiCorp impose this requirement. *See* DRAGOON, *supra* note 100, at 9; *see also* PáTu Wind Farm, LLC, v. Portland General Electric, 150 FERC ¶ 61,032 4–5 (Jan. 22, 2015) [hereinafter FERC PáTu Decision].
[184] *See* Idaho Power Company, Idaho Power Transmission Business Practices, *Section 25—Intra-hour Transmission Service Requests and Scheduling* (Nov. 12, 2013), *available at* http://www.oasis.oati.com/IPCO/IPCOdocs/IPC_BP_FINAL_Section_25_Intra-hour_Transmission_Service_Requests_and_Scheduling_v1_11-12-2013.pdf.
[185] PORTER, ET AL., *supra* note 80, at 4.
[186] FERC Order 764, *supra* note 177, at 42–43.
[187] *See* FERC PáTu Decision, *supra* note 103.
[188] DRAGOON, *supra* note 100, at 7.
[189] FERC Order 764, *supra* note 177, at 42–43.
[190] *Id.*
[191] *See, e.g.,* Letter from Donald J. Light, Assistant General Counsel, Portland General Electric, to Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission, re: Portland General Electric Company *Errata Filing for Order No. 764*, Nov. 12, 2013, *available at* http://www.oatioasis.com/PGE/PGEdocs/PGE-8_errata_Order_764.pdf.
[192] *See* PGE's answer, FERC PáTu Decision, *supra* note 103, ¶¶ 30, 31, 38 (arguing that Order 764 only applies to transmission providers and transmission customers, and because the wind farm does not purchase transmission

service on PGE's system, it is not a transmission customer, and PGE is not obligated to provide 15-minute scheduling).
[193] *Id.* ¶¶ 16, 22.
[194] *Id.* ¶¶ 30, 38.
[195] FERC Order 888 directed utilities to "functionally unbundle" their merchant services from their transmission services, which means that one corporate division manages the utility's power generation and sales, and a separate corporate division manages the utility's transmission service. FERC Order 888, supra note 51. Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services By Public Utilities, Order 888, 75 FERC 61,080 (Apr. 24, 1996), *codified at* 18 C.F.R. pts. 35, 385.
[196] *Id.* ¶¶ 30, 31, 38.
[197] PáTu Wind Farm, LLC, v. Portland General Electric, Order No. 12-316 (Or. Pub. Util. Comm'n, Aug. 21, 2012).
[198] FERC PáTu Decision, *supra* note 103, at ¶ 50, 51.
[199] *Id.* at ¶ 51; *see* 16 U.S.C. § 824a-3(a) (2012); 18 C.F.R. § 292.303(a) (2014).
[200] Idaho Power Company, Idaho Power Transmission Business Practices, *Section 25—Intra-hour Transmission Service Requests and Scheduling* §§ 25.1.1(c), 25.1.2(f) (Nov. 12, 2013), *available at* http://www.oasis.oati.com/IPCO/IPCOdocs/IPC_BP_FINAL_Section_25_Intra-hour_Transmission_Service_Requests_and_Scheduling_v1_11-12-2013.pdf.
[201] DRAGOON, *supra* note 100.
[202] *Id.* at 1, 17, 18.
[203] *Id.* at 18.
[204] The Western Governor's Association recommends adopting this approach to reduce regulation reserve requirements and save ratepayers money. PORTER, ET AL., *supra* note 151, at 4.
[205] Ken Dragoon suggests an approach where the grid operator allows "book balancing of fractional parts of the generation" over short-term periods. DRAGOON, *supra* note 100, at 13.
[206] WREZ DYNAMIC TRANSFERS, *supra* note 100, at 7.
[207] *Id.*
[208] *Id.*
[209] NERC defines "dynamic transfers" as "The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to electronically move all or a portion of the real energy services associated with a generator or load out of one Balancing Authority Area into another." NERC ACE DIVERSITY INTERCHANGE TASK FORCE, ACE DIVERSITY INTERCHANGE WHITE PAPER 4 (2012), *available at* http://www.nerc.com/docs/oc/rs/ADI_White_Paper_Final_As_Posted.pdf.
[210] *See* WREZ DYNAMIC TRANSFERS, *supra* note 100, at 7.
[211] PORTER, ET AL., *supra* note 151, at 5.
[212] DYNAMIC TRANSFER CAPABILITY TASK FORCE, PHASE III REPORT 1 (2011), *available at* http://www.columbiagrid.org/DTCTF-overview.cfm [hereinafter DTCTF PHASE III].
[213] PORTER, ET AL., *supra* note 151, at 5.
[214] In 2010, Columbia Grid and Northern Tier Transmission Group initiated a Wind Integration Study Team, which in turn created a Dynamic Transfer Capability Task Force to assess the potential impacts of increasing dynamic transfers and determine whether grid operators should impose limits on these kinds of transfers. The Task Force's Phase III Report provides recommendations for increasing dynamic transfers while maintaining grid reliability. DTCTF PHASE III, *supra* note 212, at 1.
[215] NERC, Standard INT-004-3.1—Dynamic Transfers (2014), *available at* http://www.nerc.com/pa/Stand/Reliability%20Standards/INT-004-3.1.pdf.
[216] *See* WREZ DYNAMIC TRANSFERS, *supra* note 100, at 27–28.
[217] This is closely related to intra-hour scheduling, which is discussed in section V.A.3.
[218] *See* PORTER, ET AL., *supra* note 151, at 5.
[219] *Id.* at 9.
[220] *See* Southwest Reserve Sharing Group, http://srsg.org.
[221] PORTER, ET AL., *supra* note 151, at 69, n. 255.

[222] NERC Standard BAL-002-1—Disturbance Control Performance (2012), *available at* http://www.nerc.com/files/BAL-002-1.pdf; WECC Standard BAL-002-WECC-2—Contingency Reserve (2014), *available at* http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-WECC-2.pdf.
[223] NERC Standard BAL-002-1-R1 (2012).
[224] WECC Standard BAL-002-WECC-2-R1 (2014).
[225] NERC Standard BAL-002-1-R1 (2012); WECC Standard BAL-002-WECC-2-R1 (2014).
[226] NERC Standard BAL-002-1 § A.4.2 (2012); WECC Standard BAL-002-WECC-2 §§ A.4, C.1.5 (2014).
[227] *See* NORTHWEST POWER POOL, RESERVE SHARING PROGRAM DOCUMENTATION 5 (2015), *available at* http://www.nwpp.org/documents/RSGC/NWPP-Reserve-Sharing-Doc-April-17-2015-RSG-Approved-Effective-May-1-2015.pdf [hereinafter NWPP RESERVE SHARING].
[228] NWPP RESERVE SHARING, *supra* note 150, at 5.
[229] Southwest Reserve Sharing Group, http://srsg.org.
[230] Rocky Mountain Reserve Group, *About Us*, http://www.rmrg.org/AboutUs.aspx.
[231] PORTER, ET AL., *supra* note 151, at 69, n. 255.
[232] *See* NWPP RESERVE SHARING, *supra* note 150, Attachment B; SOUTHWEST RESERVE SHARING GROUP, SRSG OPERATING PROCEDURE NO. 5, Activation of Reserves for SRSG Assistance, Qualified Loss § 2.3 (Nov. 3, 2010), available at http://srsg.org/pdf/op/SRSGOP05app110310.pdf.
[233] NERC Reliability Standard BAL-001-1 (2014).
[234] *See* Real Power Balancing Control Performance Reliability Standard, 151 FERC 61,048 (Apr. 16, 2015) (approving Reliability Standard BAL-001-2—Real Power Balancing Control Performance).
[235] *See id.* ¶ 1, n.2; NERC, RELIABILITY GUIDELINE: OPERATING RESERVE MANAGEMENT 10 (2013), *available at* http://www.nerc.com/comm/OC/Reliability%20Guideline%20DL/Operating%20Reserve%20Management%20Guideline%20-%2020130718.pdf [hereinafter NERC RELIABILITY GUIDELINE].
[236] NERC Glossary, *supra* note 61.
[237] *Id.* at 70.
[238] NERC RELIABILITY GUIDELINE, *supra* note 235, at 10.
[239] *See* WEISS, PHD, & BRUCE TSUCHIDA, *supra* note 166, at 26.
[240] A detailed explanation of the ADI program is beyond the scope of this report. For more information on this tool, see NERC ACE DIVERSITY INTERCHANGE TASK FORCE, *supra* note 209, at 4.
[241] PORTER, ET AL., *supra* note 151, at 69–70.
[242] *Id.* at 70.
[243] PORTER, ET AL., *supra* note 151, at 71.
[244] *See, e.g.,* NWPP RESERVE SHARING, *supra* note 150, Attachment B; SOUTHWEST RESERVE SHARING GROUP, SRSG OPERATING PROCEDURE NO. 5, Activation of Reserves for SRSG Assistance, Qualified Loss § 2.3 (Nov. 3, 2010), available at http://srsg.org/pdf/op/SRSGOP05app110310.pdf.
[245] NWPP RESERVE SHARING, *supra* note 150, Attachment B; SOUTHWEST RESERVE SHARING GROUP, SRSG OPERATING PROCEDURE NO. 5, Activation of Reserves for SRSG Assistance, Qualified Loss § 2.3 (Nov. 3, 2010), available at http://srsg.org/pdf/op/SRSGOP05app110310.pdf.
[246] *Id.* at 73.
[247] NREL, WESTERN WIND AND SOLAR INTEGRATION STUDY 311 (2010), *available at* http://www.nrel.gov/docs/fy10osti/47434.pdf.
[248] *See id.*
[249] NERC recommended that reserve sharing groups allow for the dispatch of contingency reserves to respond to energy imbalances "made more likely with the increasing penetration of renewables." NERC, ANCILLARY SERVICE AND BALANCING AUTHORITY AREA SOLUTIONS TO INTEGRATE VARIABLE GENERATION 18 (2011), *available at* http://www.nerc.com/files/IVGTF2-3.pdf.
[250] ACE Diversity Interchange (ADI), *available at* http://www.oasis.oati.com/PPW/PPWdocs/ADI_040107.pdf.
[251] *See* JIM LAZAR, TEACHING THE "DUCK" TO FLY (2014), *available at* http://www.raponline.org/featured-work/teach-the-duck-to-fly-integrating-renewable-energy.
[252] Herman K. Trabish, *How California is Incentivizing Solar to Solve the Duck Curve,* UTILITYDIVE.COM, Oct. 13, 2014, http://www.utilitydive.com/news/how-california-is-incentivizing-solar-to-solve-the-duck-curve/317437/.
[253] *Id.*
[254] *Id.*

[255] *Id.*
[256] Cal. Energy Commission, *California Moves to Improve Solar Incentive Program for New Homes*, Sept. 3, 2014, http://www.energy.ca.gov/releases/2014_releases/2014-09-03_nshp_incentive_nr.html.
[257] *See* Go Solar California, http://www.gosolarcalifornia.ca.gov.
[258] Clean Power Plan, *supra* note 1, at 1,165–66.
[259] *Id.* at 1,161, n.910.
[260] *Id.* at 1,160–61.
[261] *Id.* at 1,234.
[262] *Id.* at 1,167–68.
[263] *See, e.g.,* Ashlynn S. Stillwell, et al., *Energy Recovery from Wastewater Treatment Plans in the United States: A Case Study of the Energy-Water Nexus,* SUSTAINABILITY 2010 at 951 (2010) (stating that most wastewater treatment plants flare biogas); Jerry Soto, *Contracting a Methane Gas Extraction System, PUBLIC* WORKS, June 3, 2013, http://www.pwmag.com/landfills/contracting-a-methane-gas-extraction-system.aspx (listing venting and flaring as two typical ways of removing methane from landfills).
[264] *See* DAVE MOLDAL & MATT KRUMERNAUER, ENERGY TRUST OF OREGON, PUTTING WASTE TO WORK FOR OREGON: HOW ANAEROBIC DIGESTION TECHNOLOGY CAN IMPROVE OUR ENERGY FUTURE (2015), *available at* http://energytrust.org/library/forms/AnaerobicDigester_BKLT_1412_web.pdf.
[265] Clean Power Plan, *supra* note 1, at 1,232.
[266] CARL LINVILL, ET AL., THE VALUE OF GEOTHERMAL ENERGY GENERATION ATTRIBUTES (2013), *available at* http://www.yumpu.com/en/document/view/11007593/geothermal20valuation20project20aspen.
[267] *Id.* at 2–3.
[268] ELECTRIC POWER RESEARCH INSTITUTE, QUANTIFYING THE VALUE OF HYDROPOWER IN THE ELECTRIC GRID: FINAL REPORT (2013), *available at* http://www1.eere.energy.gov/wind/pdfs/epri_value_hydropower_electric_grid.pdf.
[269] Cassandra Profita, *Portland Now Generating Hydropower in its Water Pipes*, OPB.ORG, Jan. 20, 2015, http://www.opb.org/news/article/portland-now-generating-hydropower-in-its-water-pipes/.
[270] *See* Instream Energy Systems, http://instreamenergy.com.
[271] U.S. Dep't of Energy, *Energy Department to Fund R&D to Advance Low-Impact Hydropower Technologies*, ENERGY.GOV, April 9, 2015, http://energy.gov/eere/articles/energy-department-fund-rd-advance-low-impact-hydropower-technologies.
[272] Decision Adopting Emergency Rules, Decision No. C07-0829 at 10–11 (Colo. P.U.C. 2007).
[273] Clean Power Plan, *supra* note 1, at 767.
[274] *Id.* at 1,241.
[275] NERC INITIAL RELIABILITY REVIEW, *supra* note 96, at 13.
[276] Robert Fares, *Throwback Thursday: The First U.S. Energy Storage Plant*, SCIENTIFIC AMERICAN BLOG, Feb. 19, 2015, http://blogs.scientificamerican.com/plugged-in/2015/02/19/throwback-thursday-the-first-u-s-energy-storage-plant-2/.
[277] *Id.*
[278] Absaroka Energy's 250 MW Coffin Butte and 400 MW Gordon Butte pumped hydro systems both received preliminary permits from the Federal Energy Regulatory Commission (FERC) and are starting to commence site feasibility studies. *See* http://www.absarokaenergy.com.
[279] EDF Renewable Energy is developing a 600 MW pumped storage system outside of Klamath Falls, OR. *See* SWAN LAKE NORTH PUMPED STORAGE PROJECT: ECONOMIC AND FISCAL IMPACTS FROM OPERATIONS AND CONSTRUCTION (2015), *available at* http://www.edf-re.com/files/uploads/Swan_Lake_North_Project_Economic_Impact_Report_ECONorthwest_January2015.pdf.
[280] The Klickitat Public Utility District is applying for a FERC license to construct a 1,200 MW facility within a wind farm in the Columbia River Gorge. Kate Prengaman, *Klickitat PUD Wants to Build $2.5 Billion Power Storage System Near Goldendale*, YAKIMAHERALD.COM, Feb. 17, 2015, http://www.yakimaherald.com/news/2888284-8/klickitat-pud-wants-to-build-25-billion-power.
[281] *See* Energy Storage Ass'n, *Pumped Hydroelectric Storage*, http://energystorage.org/energy-storage/technologies/pumped-hydroelectric-storage.
[282] Joshua S. Hill, *Distributed Energy Storage Revenue to Exceed $16.5 billion by 2024*, CLEANTECHNICA.COM, Jan. 13, 2015, http://cleantechnica.com/2015/01/13/distributed-energy-storage-revenue-exceed-16-5-billion-2024/.

[283] For example, Beacon Power currently has three operational flywheel storage systems in the Northeast United States. Beacon Power, http://beaconpower.com.
[284] *Id.*
[285] Power South Energy Cooperative, http://www.powersouth.com/mcintosh_power_plant/compressed_air_energy.
[286] *See* B. PETER MCGRAIL, ET AL., COMPRESSED AIR ENERGY STORAGE: GRID-SCALE TECHNOLOGY FOR RENEWABLES INTEGRATION IN THE PACIFIC NORTHWEST (2013), *available at* http://caes.pnnl.gov/pdf/PNNL-22235-FL.pdf.
[287] *See* Frederika Whitehead, *Lessons From Denmark: How District Heating Could Improve Energy Security*, TheGuardian.com, Aug. 20, 2014, http://www.theguardian.com/big-energy-debate/2014/aug/20/denmark-district-heating-uk-energy-security.
[288] Many district heating systems also employ combined heat and power stations that further increase efficiency rates by collecting waste heat that is a byproduct of electricity production. Combined heat and power units are 20–60% more efficient than standard power plants. *Id.*
[289] More than 75% of Denmark's district heating is generated by combined heat and power stations, and all of the country's district heating areas have heat storage capacity. DANISH ENERGY AGENCY, DISTRICT HEATING: DANISH AND CHINESE EXPERIENCE 5, 7, *available at* http://www.ens.dk/sites/ens.dk/files/energistyrelsen/Nyheder/district_heating_danish-chinese_experiences.pdf.
[290] Whitehead, *supra* note 287.
[291] In 2014, Denmark set a world record by generating 39.1% of its total electricity from wind. Ari Phillips, *Denmark Sets World Record for Wind Power Production,* THINKPROGRESS.ORG, Jan. 7, 2015, http://thinkprogress.org/climate/2015/01/07/3608898/denmark-sets-world-record-for-wind-power/.
[292] Susan Kraemer, *How Denmark Will Integrate 50% Wind Power by 2025,* CLEANTECHNICA.COM, March 5, 2011, http://cleantechnica.com/2011/03/05/how-denmark-will-integrate-50-wind-power-by-2025/.
[293] DANISH ENERGY AGENCY, *supra* note 202, at 9.
[294] Kraemer, *supra* note 292; Helle Jeppesen, *Denmark Leads the Charge in Renewable Energy*, DW.de, Feb. 5, 2014, http://www.dw.de/denmark-leads-the-charge-in-renewable-energy/a-17603695.
[295] ANDREW SMITH, QUANTIFYING EXPORTS AND MINIMISING CURTAILMENT: FROM 20% TO 50% WIND PENETRATION IN DENMARK (2010), *available at* http://energynumbers.info/files/Andrew_Smith-Danish_wind_exports.pdf.
[296] *See generally* BHATNAGAR, ET AL., *supra* note 103.
[297] With the exception of the California ISO, the western grid does not have a competitive energy market, which means that most energy sales are conducted through bilateral contracts. Because contractual prices are often not publicly available, it can be difficult for independent developers to determine the current market price for energy storage services. *Id.* at 28–29.
[298] Cal. PUC, Decision Adopting Energy Storage Procurement Framework and Design Program, Decision 13-10-040 (Oct. 17, 2013), *available at* http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M079/K533/79533378.PDF.
[299] For example, Colorado's Section 123 Resources initiative directs the PUC to fully consider allowing a utility to rate base investments in alternative energy technologies that are not the least-cost resources, but the Commission determines are "cost-effective." Decision Adopting Emergency Rules, Decision No. C07-0829 at 10–11 (Colo. P.U.C. 2007).
[300] MARK DYSON & JAMES MANDEL, ET AL., THE ECONOMICS OF DEMAND FLEXIBILITY 5, 7 (2015), *available at* http://www.rmi.org/electricity_demand_flexibility.
[301] Clean Power Plan, *supra* note 1, at 894, 1,240. Eligible demand response actions must avoid end-use electricity consumption, rather than shift consumption to another time of day. *Id.* at 1,240, n.960.
[302] *See* Jamie Fine, *Timing is Everything: How California is Getting Electricity Pricing Right and Bringing Clean Power to the People,* THE ENERGY COLLECTIVE (July 22, 2015), http://www.theenergycollective.com/edfenergyex/2251446/timing-everything-how-california-getting-electricity-pricing-right-and-bringing-.
[303] U.S. Dep't of Energy Office of Electricity Delivery & Energy Reliability, *Demand Response,* ENERGY.GOV, http://energy.gov/oe/technology-development/smart-grid/demand-response.
[304] Idaho Power, *Flex Peak Program,* https://www.idahopower.com/EnergyEfficiency/Business/Programs/FlexPeak//default.cfm.

[305] PacifiCorp operates as Pacific Power in Oregon, Washington, and California, and Rocky Mountain Power in Idaho, Utah, and Wyoming. *See* Pacific Power, Energy Exchange, https://www.pacificpower.net/bus/se/oregon/lc.html?cq_ck=1388530791308; Rocky Mountain Power, Energy Exchange, https://www.rockymountainpower.net/bus/se/utah/pm/lc1.html.
[306] PNM Power Saver Program, http://www.pnmpowersaver.com/business.php.
[307] *See* PG&E, Automated Demand Response Program, http://www.pge.com/en/mybusiness/save/energymanagement/adrp/index.page.
[308] Robert Walton, *ComEd-Nest-Xfinity Demand Response Program Paves the Way for New Utility Business Models,* UtilityDive.com, June 3, 2015, http://www.utilitydive.com/news/comed-nest-xfinity-demand-response-program-paves-way-for-new-utility-busine/400148/.
[309] *Id.*
[310] *Id.*
[311] Opower, *Demand Response*, http://opower.com/solutions/demand-response.
[312] Kevin Hamilton and Tom Mercer, *Behavioral Demand Response Reduced Peak Demand by up to 5% This Summer. Here's What That Means for all 50 States*, Oct. 24, 2014, http://blog.opower.com/2014/10/behavioral-demand-response-5-percent/. AMI data is data collected through "advanced metering infrastructure," which the U.S. Department of Energy describes as "an integrated system of smart meters, communications networks, and data management systems that enables two-way communication between utilities and customers." SmartGrid.gov, *Advanced Metering Infrastructure and Customer Systems,* https://www.smartgrid.gov/recovery_act/deployment_status/ami_and_customer_systems.
[313] Opower, *Capacity Savings Potential of Behavioral Demand Response*, http://www.opower.com/bdrpotential/#us.
[314] The Court of Appeals for the D.C. Circuit held that demand response is part of the retail electricity market, and because states have exclusive jurisdiction to regulate the retail market, they have exclusive jurisdiction over demand response incentives. Electric Power Supply Ass'n v. FERC, 753 F.3d 216 (D.C. Cir. 2014). However, the Supreme Court granted certiorari to review the D.C. Circuit's ruling. Electric Power Supply Ass'n v. FERC, 753 F.3d 216 (D.C. Cir. 2014), *cert. granted* (U.S. May 4, 2015) (No. 14-840).
[315] 16 U.S.C. § 2621.
[316] Federal law encourages state regulators to adopt ratemaking policies that promote utility investments in demand response. 16 U.S.C. § 2621(d)(8) ("The rates allowed to be charged by a State regulated electric utility shall be such that the utility's investment in and expenditures for energy conservation, energy efficiency resources, and other demand side management measures are at least as profitable, giving appropriate consideration to income lost from reduced sales due to investments in and expenditures for conservation and efficiency, as its investments in and expenditures for the construction of new generation, transmission, and distribution equipment. Such energy conservation, energy efficiency resources and other demand side management measures shall be appropriately monitored and evaluated.").
[317] Clean Power Plan, *supra* note 1, at 1,196.
[318] *Id.* at 915.
[319] Clean Power Plan, *supra* note 1, at 914.
[320] *Id.* at 72.
[321] *Id.* at 889.
[322] *Id.*
[323] *Id.* at 1,261.
[324] *Id.* at 1,218.
[325] *Id.* at 1,240–52.
[326] *Id.* at 1,269–70.
[327] *Id.* at 1,275.
[328] *Id.* at 1,282.
[329] *Id.* at 1,215.
[330] *Id.* at 1,226–27.
[331] *Id.* at 894.
[332] *Id.* at 895.
[333] *Id.* at 895, 1,171.
[334] *Id.* at 1,172–73.

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336 *Id.* at 1,175–76; 1,182–83.
337 *Id.* at 1,176.
338 *Id.* at 1,293–94, 1,197–98.
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