C

2017 PSE Integrated Resource Plan

Environmental and Regulatory Matters

This appendix summarizes the recent and changing environmental rules and regulations that apply to PSE energy production activities.

Contents

1. ENVIRONMENTAL PROTECTION AGENCY REGULATIONS

Coal Combustion Residuals

On April 17, 2015, the United States Environmental Protection Agency (EPA) published a final rule, effective October 19, 2015, that regulates coal combustion residuals (CCRs) under the Resource Conservation and Recovery Act, Subtitle D. The CCR rule addresses the risks from coal ash disposal, such as leaking of contaminants into ground water, blowing of contaminants into the air as dust, and the catastrophic failure of coal ash containment structures by establishing technical design, operation and maintenance, closure and post-closure care requirements for CCR landfills and surface impoundments, and corrective action requirements for any related leakage. The rule also sets out recordkeeping and reporting requirements including posting specific information related to CCR surface impoundments and landfills to a publicly-accessible website.

Mercury and Air Toxics Standard (MATS)

The EPA published the final Mercury and Air Toxics Standard in February 2012 to reduce air pollution from coal and oil-fired power plants with a capacity equal to or greater than 25 megawatts (MW). The MATS rule establishes emissions limitations at coal-fired power plants for mercury of 1.2 lbs per trillion British thermal units (TBtu), and for acid gases and certain toxic heavy metals using a particulate matter surrogate of 0.03 lb per million British thermal units (MMBtu).[1]

The regulations have been challenged in the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) in White Stallion Energy Center v. EPA, and on appeal in the U.S. Supreme Court in Michigan v. EPA. Petitioners focused on EPA's finding that mercury controls for electric power plants were "appropriate and necessary," a prerequisite to regulation under Section 112(n) of the Clean Air Act. Petitioners argued that the agency found few direct benefits from controlling mercury or other air toxics. The vast majority of the monetized benefits in EPA's analysis would come from reduced emissions of particulates, specifically PM2.5, which the pollution control equipment would achieve as a co-benefit. Petitioners also argued that EPA had a duty to consider cost in determining whether the standards were appropriate and necessary, and did not do so.

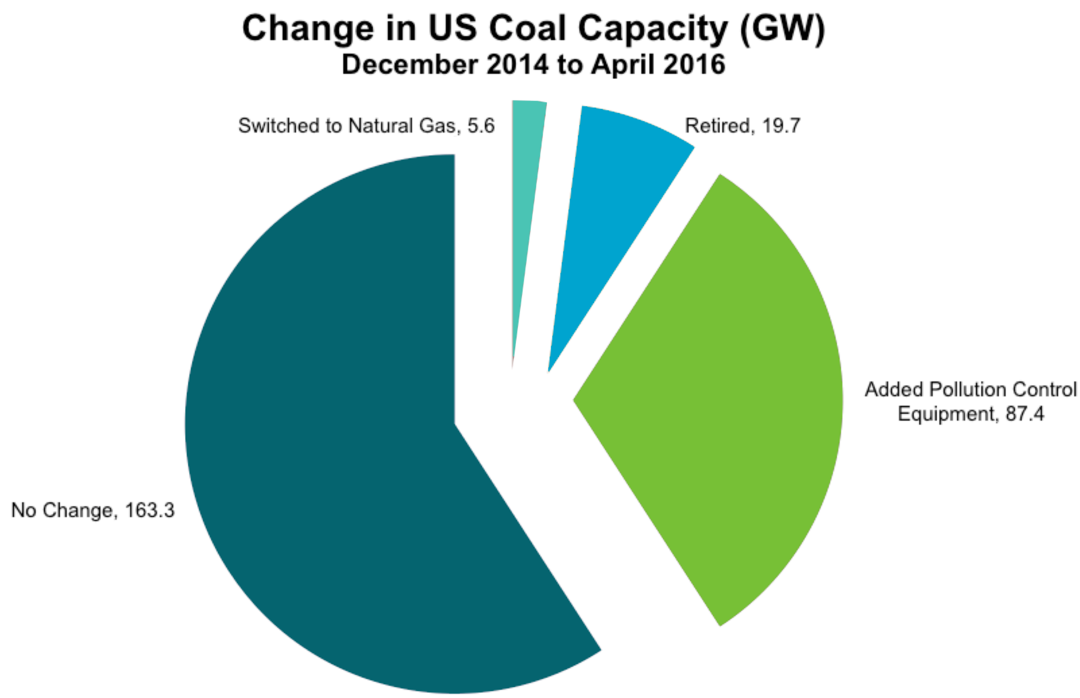
1 / *Appendix K, Colstrip, describes Colstrip's compliance with the MATS rule.*

On June 29, 2015, the Supreme Court agreed in a 5-4 vote. The Court held that EPA interpreted the statute's "appropriate and necessary" language unreasonably when it deemed cost irrelevant to the decision to regulate power plants. The Court found the ratio of direct benefits from the rule to its expected cost particularly troubling: "One would not say that it is even rational, never mind 'appropriate,' to impose billions of dollars in economic costs in return for a few dollars in health or environmental benefits."

The case was remanded to the D.C. Circuit for further proceedings, and EPA prepared a "supplemental appropriate and necessary" finding that it finalized in April 25, 2016 after taking public comment. Fifteen states, led by Michigan, have filed suit challenging EPA's "Supplemental Finding that It Is Appropriate and Necessary to Regulate Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units." As of September 2016, the rule remains in effect while the D.C. Circuit considers whether EPA's action in response to the Supreme Court decision has properly addressed the Court's concerns.

According to the Energy Information Administration (EIA), $6.1 billion was invested to comply with MATS or other environmental regulations from 2014 to 2016, with 87.4 gigawatts (GW) of total capacity adding pollution controls as a compliance option. This is less than the EPA's December 2011 estimate that MATS compliance would cost utilities and potentially consumers $9.6 billion per year. The 19.7 GW of smaller and older coal-burning units that retired in that time frame also exceeded EPA's 2011 estimate of 4.7 GW. Overall, coal-fired generation capacity dropped from 299 GW at the end of 2014 to 276 GW as of April 2016, and its share of total electricity generation declined from 39 percent in 2014 to 28 percent in the same period.

Figure C-1: Change in U.S. Coal Capacity, December 2014 to April 2016



Clean Water Act

Cooling Water Intake and Discharge

The EPA finalized the changes to Section 316(b) of the Clean Water Act that apply to power plant standards in May 2014.

The rule's requirements address these potential fisheries impacts:

- Existing facilities with a design intake flow of greater than 2 million gallons per day, where more than 25 percent is used for cooling, are required to select from 9 compliance options related to impingement (fisheries) mortality.
- Existing facilities that withdraw at least 125 million gallons per day are required to monitor fisheries entrainment and assess the costs, benefits and other adverse environmental impacts of measures for reducing entrainment mortality. Based on these reports, the regulatory agency selects the best technology available for reducing entrainment mortality at a facility.
- New units that add electrical generation capacity at an existing facility are required to install technologies that reduce impingement and entrainment to a level equivalent to closed-cycle cooling.

The rule requires power plants to install any one of a variety of technologies to reduce the amount of fish and other aquatic life killed by cooling water intake pipes.

Environmental groups filed three separate challenges to the rule on September 2, 2014, in the U.S. Court of Appeals for the Second Circuit (Second Circuit). They contend that the EPA gave utilities too much flexibility in finding a way to comply and do not adequately protect fish and aquatic life. On September 4, 2014, Entergy Corporation and the Utility Water Act Group, a coalition of 191 energy companies and three utility trade associations, filed a joint challenge on behalf of utility companies. The industry coalition, while not challenging specific issues, has taken issue with the data EPA used to estimate the costs and benefits of the rule.

The Second Circuit is now tasked with deciding whether to send the rule back to the agency for further revision based on environmentalists' argument that it isn't protective enough, or to trim what industry groups contend are inappropriate components. On May 20, 2016, the Sierra Club and more than 20 other environmental groups and industry members — including the American Chemistry Council, the American Petroleum Institute and Entergy Corp. — filed opening briefs. On June 3, 2016, the Clean Air Task Force filed an amicus brief on behalf of the environmental petitioners. On October 12, 2016, EPA responded, asking the Second Circuit to uphold the agency's regulations. The EPA defended its rule saying neither group's remedy is necessary and that the agency followed Congress' direction. The lawsuit is still pending.

Steam Electric Power Generating Effluent Guidelines

On September 30, 2015, the EPA finalized a rule to regulate wastewater discharges from power plants. The new rule sets limits on dissolved pollutants permitted in these discharges, and focuses on mercury, selenium and arsenic (toxic metals previously unregulated in this context).

The final rule applies to all steam electric power plants with more than 50 megawatts in production capacity and to oil-fired plants. There are about 1,080 steam electric power plants in the U.S., and 134 of those will have to make new investments to meet the requirements of the effluent limitation guidelines according to the agency. The regulations will take effect in 2018, and compliance will be phased in through 2023.

Along with effluent limits on toxic metals and dissolved solids, the rule establishes zero discharge limits on pollutants in ash transport water and flue gas mercury control wastewater. Many units in the Pacific Northwest will be compliant with their current controls, and therefore will not incur additional compliance costs. Colstrip is a Zero Liquid Discharge (ZLD) facility, so it will not be affected by the rule.

The Regional Haze Rule (Montana)

Adopted in 1998, the Regional Haze program is a 64-year program administered by the EPA under federal law to improve visibility. Specifically, the rule is aimed at improving visibility in mandatory Class I areas (National Parks, National Forests and Wilderness Areas); it is not a health-based rule. The rule requires each state to prepare an analysis of visibility impairments to Class I areas and develop plans to eliminate man-made impairment by 2064. Major sources that began construction before 1977 (including Colstrip Units 1 & 2) must bring emission controls to Best Available Retrofit Technology (BART) standards during the initial review cycle. "Reasonable Progress" requirements call for an updated analysis of impacts every five years. States are also required to constantly decrease haze in certain scenic areas of the country over time according to a "Glide Path." Power plant emissions contributing to haze are evaluated in phases every 10 years, and more stringent emission controls are required as needed to stay below the Glide Path.

In September 2012, the EPA published its Final Implementation Plan (FIP) for Colstrip, covering both the BART and Reasonable Progress requirements, with implementation required within five years.

There were no immediate requirements for Colstrip Units 3 & 4, but EPA determined that Colstrip Units 1 & 2 needed to upgrade pollution controls to meet new sulfur dioxide and nitrogen oxide limits. On November 15, 2012, the Sierra Club filed an appeal of the FIP with the U.S. Court of Appeals for the Ninth Circuit (Ninth Circuit), and Colstrip operator Talen Energy also filed an appeal. The case was heard on May 15, 2014, in Seattle, Wash. On June 9, 2015, a three judge panel of the Ninth Circuit reviewed EPA's first phase requirements for Colstrip and found that the EPA had not adequately justified the need for two of the control technologies; they remanded these two issues back to EPA for revision. The ruling in no way affects the future planning periods for the Regional Haze program or the Glide Path.

The current EPA assessment is that the state of Montana will require significant emission reductions to meet the natural visibility goal by 2064. This means that additional emission reductions will be necessary in future 10-year planning periods, beginning in the 2018-2028 period, and there is risk and uncertainty regarding potential costs.

In 2013, the Sierra Club and the Montana Environmental Information Center (MEIC) filed a citizen suit alleging that the six Colstrip owners (Talen Montana LLC, PSE, Avista Corporation, Portland General Electric Company, NorthWestern Corporation and PacifiCorp) violated the Clean Air Act by making modifications without getting the proper permits or installing modern pollution controls. On July 12, 2016, a settlement was reached in which Talen Energy and PSE agreed to a six-year time frame for shutting down Colstrip Units 1 & 2, and the Sierra Club and MEIC agreed to drop their suit. Originally, the suit targeted all four Colstrip units, but the environmental groups agreed to drop the whole suit when the agreement to shut down the two older units was reached. Talen Montana LLC and Puget Sound Energy will have until July 1, 2022, to completely shut down Units 1 & 2, and they also agreed to limit nitrogen oxide and sulfur dioxide emissions from those units while they continue to operate. The other four owners have stakes only in Units 3 & 4.

Oregon and Washington both recently passed legislation affecting the Colstrip power plant. Oregon Gov. Kate Brown approved legislation in March 2016 pushing the state away from importing coal-sourced electricity, and Washington Gov. Jay Inslee later signed a bill allowing PSE to set aside money for the decommissioning of the two older Colstrip units.

For more information on the EPA FIP, see http://www2.epa.gov/sites/production/files/2014-02/documents/epafinalactononmontanaregionahazeplan.pdf.

For the draft Federal Implementation Plan containing EPA’s analyses and cost estimates, see https://federalregister.gov/a/2012-8367.

National Ambient Air Quality Standards (NAAQS)

The Clean Air Act establishes two types of national air quality standards. Primary standards set limits to protect public health, including the health of "sensitive" populations such as asthmatics, children and the elderly. Secondary standards set limits to protect public welfare, including protection against visibility impairment, damage to animals, crops, vegetation and buildings. These ambient level standards apply uniformly throughout the states.

The Clean Air Act required EPA to set NAAQS for widespread pollutants from numerous and diverse sources considered harmful to public health and the environment. EPA has set NAAQS for the "criteria" pollutants (carbon monoxide, oxides of nitrogen, oxides of sulfur, volatile organic compounds and particulate matter); periodic review of the standards and the science on which they are based is required.

Each time the NAAQS are revised, the states must evaluate whether any parts of the state exceed the standard; these are “non-attainment” areas. If a state contains any non-attainment areas, it must propose a plan and schedule to reduce emissions in order to achieve attainment approval by the EPA. Currently the Colstrip area of Montana is in attainment for all criteria pollutants. Reductions in Colstrip emissions for sulfur dioxide (SO_2), nitrogen dioxide (NO_X) and particulate matter (PM) to meet the MATS Rule and the EPA FIP are expected to keep the area in attainment with any NAAQS revisions with no further actions required.

Ozone NAAQS in Washington State

On October 1, 2015, EPA strengthened the ozone NAAQS by lowering the allowable level of ozone from 75 to 70 parts per billion (ppb).[2] To meet the standard, the ozone design value of an area must be equal to or less than 70 ppb.[3] Non-attainment designations were to be set by October 1, 2017, and non-attainment areas would have 3, 6 or 9 years to meet the new standard, depending on the level of severity.

On October 1, 2016, Washington state's Department of Ecology (Ecology) informed EPA that overall, Washington meets the new tougher standards; however, a lack of data collected in Benton, Franklin and Walla Walla Counties required Ecology to mark these areas as "unclassified." The EPA standard requires three years of monitoring data. So far, Ecology has monitored ozone in the Tri-Cities for only one year, and the agency has discovered that ozone can reach high levels in the southern Columbia Basin. Ecology is conducting a special study to help pinpoint the origin of high Tri-Cities ozone levels.

EPA was scheduled to issue final designations by October 1, 2017, based on ozone monitoring data from 2014-2016, but instead, in June 2017 the agency determined that it needed more time to consider the designation decisions. The EPA then moved to delay the designations until October 2018; however, facing new lawsuits from environmental and public health groups as well as a handful of states, in August 2017 the agency scrapped its effort to delay the designations. On October 3, 2017, it was reported that EPA had missed its October 1, 2017 deadline for informing states which counties and regions were out of attainment with the 2015 NAAQS standards for ozone. The EPA released a statement to the press stating it had "no further information at this time." In response to the lack of action from the EPA, on October 3, 2017, Earthjustice filed a notice of intent to sue the EPA on behalf of the Sierra Club and other environmental and public health groups for missing the October 1 deadline. Due to the uncertainty now surrounding the ozone standards, PSE cannot predict the outcome of this matter.

2 / 80 FR 65292, October 26, 2015
3 / The ozone design value is the fourth-highest maximum daily 8-hour ozone concentration per year, averaged over three years.

Greenhouse Gas Emissions

Section 111(b) of the Clean Air Act

On January 8, 2014, the EPA issued a proposed New Source Performance Standard (NSPS) for the control of carbon dioxide (CO_2) from new power plants that burn fossil fuels under section 111(b) of the Clean Air Act. For coal-fired sources, the EPA is proposing an emissions limit of 1,100 lb CO_2 per megawatt hour (MWh); for natural gas combined-cycle sources; limits would be set at 1,000 to 1,100 lb CO_2 per MWh, depending on the size and type of unit. (The EPA's original recommendations, issued on April 8, 2012, were rescinded after receiving 2.5 million comments.) Under the January 2014 proposal, the Agency concluded that carbon capture and storage (CCS) has been adequately demonstrated as a technology for controlling CO_2 emissions in full-scale commercial applications at coal-fired electrical generating units; however, it reached the opposite conclusion in the case of gas-fired generators: that CCS is not adequately demonstrated. PSE submitted comments before the end of the comment period on May 9, 2014.

On August 3, 2015, EPA issued a final rule combining its new and modified proposals into one rulemaking and made several changes. The final rule separates standards for new power plants fueled by natural gas and coal from existing plants. New natural gas power plants can emit no more than 1,000 lbs of CO_2 per MWh, which is achievable with the latest combined-cycle technology. New coal power plants can emit no more than 1,400 lbs CO_2 per MWh. Coal plants would not specifically be required to employ carbon capture and storage (CCS), but CCS was reaffirmed by EPA as Best System of Emissions Reduction (BSER). The 111(b) standards are implemented by the states.

Section 111(d) of the Clean Air Act

The EPA announced the final rule under section 111(d) of the Clean Power Plan for Existing Power Plants on August 3, 2015, and it was published on October 23, 2015. The final version included several changes from the draft rule. Specifically, the EPA excluded energy efficiency from the "building blocks" states could use to meet the standard, leaving just three:

- increased efficiency for coal plants,
- greater utilization of natural gas plants, and
- increased renewable sources.

In the final rule, the EPA provided more flexibility in achieving interim goals by phasing in the reduction, giving states the option to set their own interim compliance Glide Path, and pushing the start of compliance to 2022. The EPA also adjusted the 2012 baseline to address hydroelectricity variability and provided specific CO_2 mass targets by year for each state.

States have broad flexibility to pick a rate-based or mass-based approach, to design compliance options, and to decide how to allocate credits and whether to allow trading. The EPA also gave states the option of seeking additional time, if necessary, to formulate a state plan. States must submit a plan or an “initial submittal” within one year, but they can request up to two additional years to finalize a state plan. Thus, states must submit a plan for implementing CO_2 reductions to the EPA one to three years following issuance of the final rule.

In the October 2015 final version of the rule, the CO_2 goal for Montana became 26 percent more stringent than the draft version, and the CO_2 goal for Washington became 35 percent less stringent. By 2030 Montana must reduce CO_2 emissions from coal plants from 20.5 million tons of CO_2 to 11.3 million tons of CO_2, which is a 45 percent reduction in CO_2 emissions. For reference, Colstrip Units 1, 2, 3 and 4 combined emit 18 million tons of CO_2.

Soon after the EPA published the Clean Power Plan, 27 states, along with several utilities, electric cooperatives and industry groups, challenged the rule’s legality in the U.S. Court of Appeals for the District of Columbia Circuit (DC Circuit). On April 28, 2017, the DC Circuit ruled to put the 27 state lawsuits challenging the plan on hold for 60 days without deciding whether the initiative is legal. That decision followed a request to halt the case from EPA.

2. STATE AND REGIONAL ACTIVITY

California Cap-and-trade Program

On December 16, 2010, the California Air Resources Board (CARB) adopted final rules to enact cap-and-trade provisions in accordance with California's Global Warming Solutions Act of 2006 (AB-32). The final rule defines the ground rules for participating in the cap-and-trade program, including enforcement and linkage to outside programs. The compliance obligations became binding on January 1, 2013.

AB 32 requires California to reduce greenhouse gas (GHG) emissions to 1990 levels by 2020. It directs power providers to account for emissions from in-state generation and imported electricity. The regulatory approach assigns the electricity importer as the "first deliverer" of imported electricity and thus the point of regulation. Cap-and-trade regulations distinguish between "specified" and "unspecified" sources of electricity. An unspecified source means electricity generation that cannot be matched to a particular generating facility; these sources are subject to the default emission factor of 0.428 metric tons (MT) of carbon dioxide equivalents (CO_2e)[4] per MWh. A specified source is a particular generating unit or facility for which electrical generation can be confidently tracked due to full or partial ownership or due to its identification in a power contract, including any California-eligible renewable resource or an asset-owning or asset-controlling supplier. Imports from specified sources are eligible for a source-specific emission factor. To be eligible for a source-specific emission factor, imported electricity must not only come from a specified source, but any renewable energy credits associated with the electricity must be retired and verified. Imported electricity can be assigned an emission factor lower than the default emission factor only if the electricity is directly delivered, meaning the facility has a first point of interconnection with a California balancing authority or the electricity is scheduled for delivery from the specified source into a California balancing authority via a continuous transmission path.

4 / The major greenhouse gasses have different-sized impacts on the atmosphere. Climate scientists have developed a scale that translates the impact of other gasses into "CO_2 equivalents" to allow for an apples-to-apples comparison of the impacts of the different gasses.

Washington State

In 2008, the Washington legislature recognized that climate changes posed serious threats to the state's economic well-being, public health, natural resources and environment. To limit the impacts of climate change, the legislature required that the state reduce its greenhouse gas emissions by setting limits on those emissions (RCW 70.235). The legislature also required the limits be reviewed and recommendations be made by the Department of Ecology using the most current global, national and regional climate science. The regulations established pursuant to 70.235 to limit greenhouse gas emissions in the state are discussed in this section.

Greenhouse Gas Emissions Performance Standard

Washington state law RCW 80.80.060(4), the GHG Emissions Performance Standard (EPS), establishes a limit of 970 lbs of CO_2 emissions per MWh from new baseload generating resources, and it prohibits utilities from entering into long-term contracts of 5 years or more to acquire power from existing generating resources that exceed this standard. Contracts of less than 5 years are allowed.

This means that PSE is prohibited from building or purchasing baseload generation resources that exceed the emission performance standard. Investor-owned utilities like PSE may apply to the Washington State Utilities and Transportation Commission for exemptions based on certain reliability and cost criteria.

The law was amended in 2011. This amendment incorporated changes related to the negotiated shutdown of the TransAlta coal-fired power plant located near Centralia, Wash. The change allows TransAlta to enter into "coal transition power" contracts with Washington utilities. It exempts TransAlta and the coal transition power contracts from complying with the EPS until the dates the coal units are required to meet the EPS in 2020 (for Unit 1) and 2025 (for Unit 2).

Carbon Dioxide Mitigation Program

In 2004, the Washington state legislature passed Substitute House Bill 3141, later codified in RCW 80.70. The law requires fossil-fueled thermal power plants above 25 megawatts (net output of the electric generator) to provide mitigation for 20 percent of the CO_2 emissions it produces over a 30-year period. The mitigation requirement applies to all new power plants filing for a Site Certification Agreement or Notice of Construction after July 1, 2004. The mitigation requirement also applies to modifications of existing plants permitted by Washington's Department of Ecology or a local air quality agency that will increase power production capacity by 25 MW or more, or increase CO_2 emissions by 15 percent or more.

If mitigation is triggered, compliance must be attained through any one or a combination of these methods:

1. Paying an “Independent Qualified Organization” to verify compliance,
2. Purchasing permanent, verifiable carbon credits, or
3. Using a self-directed mitigation program.

If the third option is chosen, the mitigation program must be identified within a plan submitted as part of the permit application. Payment to a qualified organization and the cost for a self-directed mitigation program are initially limited to an amount derived by multiplying the tons of CO_2 emissions to be mitigated by $1.60.

Washington Clean Air Rule

On September 15, 2016, Ecology finalized the Clean Air Rule (CAR) to achieve the state’s statutory GHG emission reduction goals. Specifically, Washington has committed to reducing state GHG emissions to 1990 levels by 2020; 25 percent below 1990 levels by 2035; and 50 percent below 1990 levels by 2050. The rule went in to effect October 17, 2016.

The CAR regulations apply to certain sources that meet prescribed GHG emissions thresholds, including (1) stationary sources located in Washington (e.g., electric power generators, landfill and waste operators, chemical and material manufacturers, etc.); (2) petroleum product producers located in or importing to Washington; and (3) natural gas distributors located in Washington. Sources that fall below the applicable GHG emissions threshold may choose to participate voluntarily in the program. The threshold for the first compliance period, from 2017 to 2019, is 100,000 million metric tons of CO_2 equivalent per year ($MMtCO_2e$ per year). Starting in 2020, the threshold is reduced every 3 years until it reaches 70,000 $MMtCO_2e$ per year in 2035. Once a source exceeds the emissions threshold, the source is subject to CAR and must comply thereafter. However, a source may be eligible to exit the program if its GHG emissions fall below 50,000 $MMtCO_2e$ for three consecutive years.

Due to concerns about CAR’s economic impact on entities that participate in global markets, Ecology has designated some sources as “energy-intensive, trade-exposed industries” (EITEs). EITEs include pulp and paper mills, aluminum, chemical, steel and cement facilities, and other manufacturers. EITEs, as well as petroleum product importers, are given an additional three years (until the second compliance period begins in 2020) before CAR would apply to them. EITE-covered parties also are offered an alternative and potentially less stringent compliance pathway that permits use of efficiency-based, rather than mass-based, GHG emission reduction targets. Non-EITE parties, on the other hand, must reduce emissions by 1.7 percent from their baseline GHG emissions each year until 2035.

If a covered party has attributed emissions above its emission reduction pathway level, the party must acquire emission reduction units (ERUs) from other sources equal to its excess emissions. An ERU represents one $MtCO_2e$ per year. The ERUs can be generated by (i) other affected sources that reduce emissions below their emission reduction pathway level; (ii) acquiring allowances from other states or provinces that have established, multi-sector GHG programs (such as the CARB cap-and-trade program); or (iii) a limited list of activities that reduce or abate GHG emissions in Washington. At the end of each three-year compliance period, covered parties must submit a compliance report to Ecology. The compliance report must contain: (1) a record of ERUs generated; (2) a record of ERUs banked; (3) a record of ERU transactions; and (4) documentation that a third-party verified the compliance report. Ecology plans to develop a registry to track ERUs and also create an ERU reserve to encourage economic growth and support environmental justice.

Ecology estimates that CAR will cost between $1.4 billion to $2.8 billion over 20 years. The department assumes that covered parties will be able to directly reduce their emissions at a marginal cost of $23 to $57 per ERU. It also projects that covered parties will have the option of reducing emissions through projects at a marginal cost of $5 to $29 per ERU and/or obtain allowances or renewable energy credits (RECs) at a marginal cost of $3 to $14 per ERU.

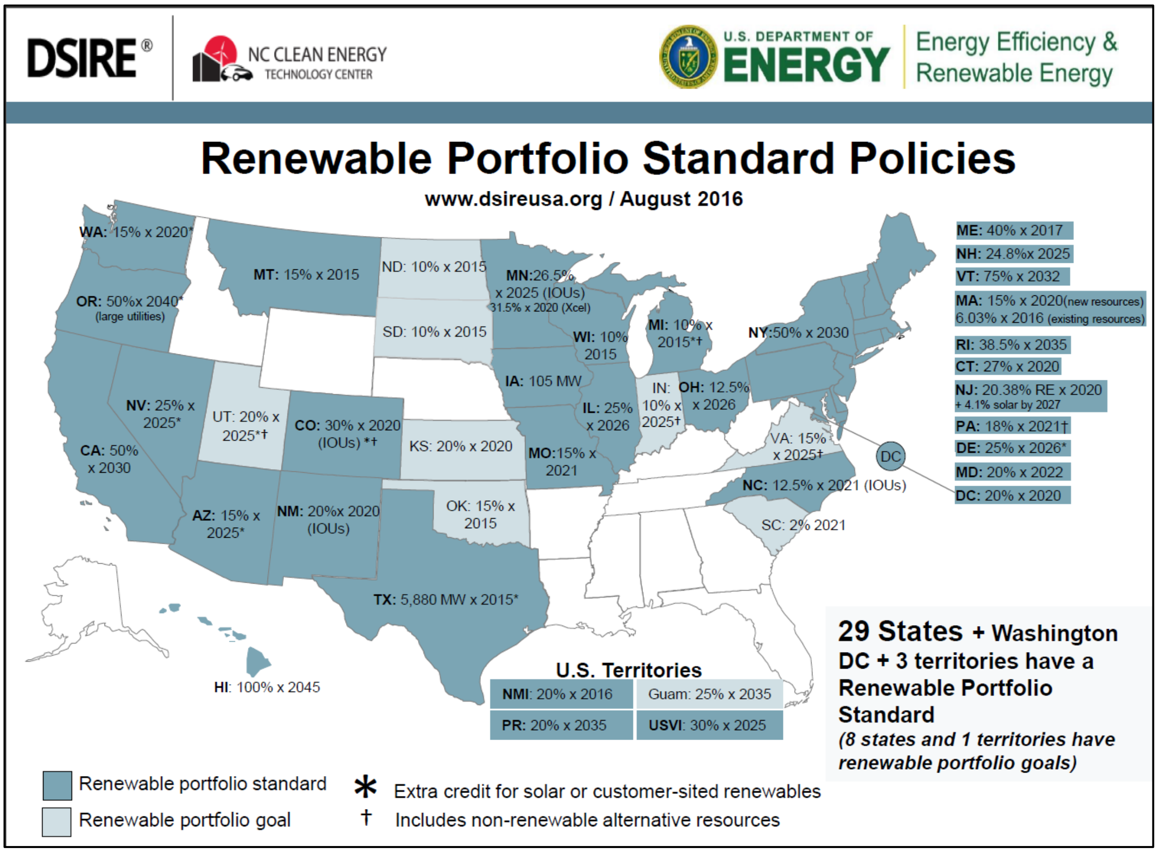
Renewable Portfolio Standards (RPS)

Renewable portfolio standards require utilities to obtain a specific portion of their electricity from renewable energy resources. Of the 11 Western interconnection states, eight have binding renewable energy targets, one has a voluntary goal, and two have no RPS in place. PSE has met Washington's RPS requirement to meet 3 percent of load with renewable resources for target years 2012-2015 and is on track to meet the RPS requirements of 9 percent for 2016-2019 and 15 percent by 2020. RPS provisions vary widely among the different jurisdictions in the absence of a federal mandate. Differences include the specific portion of renewable resources required, the timeline to meet the requirements, the types of resources that qualify as renewable, the geographic location from which renewable resources can be sourced, eligible commercial on-line dates and any applicable technology carve-outs (such as solar). The result is a patchwork of regulatory mandates, evolving regulations and segregated environmental markets. Managing these moving parts is complex from both a resource acquisition perspective and an environmental markets perspective.

PSE must actively monitor RPS requirements throughout the Western region, because the interconnectedness of the grid and regional energy markets means that changes in one state can have a pronounced impact on the entire system. In particular, PSE pays close attention to requirements in Oregon, California and Idaho (which currently has no RPS).

Figure C-1, below, illustrates the wide variety of RPS requirements that exist. The table in Figure C-2 lists the current RPS requirements for each state within the Western Interconnect.[5]

Figure C-1: RPS Requirements by State



5 / Per Figure C-2, State RPS and Eligible Technologies are drawn from the Western Interstate Energy Board's publication Exploring and Evaluating Modular Approaches to Multi-State Compliance with EPA's Clean Power Plan in the West, April 29, 2015, with updated RPS requirements from DSIRE.

Figure C-2: RPS Requirements for States in the Western Interconnect

STATE	RPS	Renewable Generation as of 10/14	ELIGIBLE RENEWABLE ENERGY
Arizona	15% by 2025	294 GWh	Solar water heat, solar space heat, solar thermal electric, solar thermal process heat, photovoltaics, landfill gas, wind, biomass, hydroelectric, geothermal electric, geothermal heat pumps, combined heat and power (CHP)/cogeneration (CHP only counts when the source fuel is an eligible RE resource), solar pool heating (commercial only), daylighting (non-residential only), solar space cooling, solar HVAC, anaerobic digester, small hydroelectric, fuel cells using renewable fuels, geothermal direct-use, additional technologies upon approval
California	20% by 12/31/2013 25% by 12/31/2016 33% by 12/31/2020 40% by 12/31/2024 45% by 12/31/2027 50% by 12/31/2030	3,350 GWh	Solar thermal electric, photovoltaics, landfill gas, wind, biomass, geothermal electric, municipal solid waste, energy storage, anaerobic digestion, small hydroelectric, tidal energy, wave energy, ocean thermal, biodiesel, and fuel cells using renewable fuels
Colorado	Investor-owned utilities (IOUs): 30% by 2020; Co-ops serving >100,000 meters: 20% by 2020; Co-ops serving <100,000 meters: 10% by 2020; Muni-cipal utilities serving >40,000 customers: 10% by 2020	666 GWh	Solar thermal electric, photovoltaics, landfill gas, wind, biomass, hydroelectric, geothermal electric, recycled energy, coal mine methane (if the Colorado Public Utilities Commission determines it is a GHG-neutral technology), pyrolysis of municipal solid waste (if the Commission determines it is a GHG-neutral technology), anaerobic digester, and fuel cells using renewable fuels
Idaho	None	287 GWh	N/A
Montana	15% by 2015	197 GWh	Solar thermal electric, photovoltaics, landfill gas, wind, biomass, hydroelectric, geothermal electric, compressed air energy storage, battery storage, flywheel storage, pumped hydro (from eligible renewables), anaerobic digester, and fuel cells using renewable fuels
New Mexico	IOUs: 20% by 2020; Rural electric cooperatives: 10% by 2020	203 GWh	Solar thermal electric, photovoltaics, landfill gas, wind, biomass, hydroelectric, geothermal electric, zero emission technology with substantial long-term production potential, anaerobic digester, and fuel cells using renewable fuels
Nevada	25% by 2025	357 GWh	Solar water heat, solar space heat, solar thermal electric, solar thermal process heat, photovoltaics, landfill gas, wind, biomass, hydroelectric, geothermal electric, municipal solid waste, waste tires (using microwave reduction), energy recovery processes, solar pool heating, anaerobic digestion, biodiesel, and geothermal direct use
Oregon	Large IOUs: 50% by 2040; large consumer-owned utilities: 25% by 2025; small utilities: 10% by 2025; smallest utilities: 5% by 2025	499 GWh	Solar thermal electric, photovoltaics, landfill gas, wind, biomass, hydroelectric, geothermal electric, municipal solid waste, hydrogen, anaerobic digestion, tidal energy, wave energy, and ocean thermal
Utah	20% of adjusted retail sales by 2025	90 GWh	Solar water heat, solar space heat, geothermal electric, solar thermal electric, solar photovoltaics, wind (all), biomass, hydroelectric, hydrogen, municipal solid waste, combined heat & power, landfill gas, tidal, wave, ocean thermal, wind (small), hydroelectric (small), anaerobic digestion
Washington	15% by 2020 and all cost-effective conservation	631 GWh	Solar thermal electric, photovoltaics, landfill gas, wind, bio-mass, incremental and low-head hydroelectric, geothermal electric, anaerobic digestion, tidal energy, wave energy, ocean thermal, and biodiesel
Wyoming	None	357 GWh	N/A

NOTE: Approved technologies are generated in the state (excluding hydro generation). In many cases, generation in one state is used for RPS compliance in a different state.

California Renewable Portfolio Standard

The size and aggressiveness of California's RPS mandate make it the region's primary driver of renewable resource availability and cost, REC product availability and cost, and transmission and integration.

California has one of the most aggressive RPS mandates in the nation. Senate Bill 1078 established the California RPS program in 2002. It was accelerated in 2006 by Senate Bill 107. In 2008, Executive Order S-14-08 increased the requirement to 33 percent by 2020. Two RPS bills were passed at the end of the 2009 legislative session, however, the governor elected not to sign either. Instead, he signed Executive Order S-21-09, which allowed the California Air Resources Board (CARB), under its AB 32 authority, to adopt a regulation consistent with the 33 percent RPS target established in Executive Order S-14-08. In 2010, the CARB adopted its Renewable Electricity Standard (RES), requiring 33 percent by 2020. Legislative endorsement of this standard was achieved when Governor Jerry Brown signed Senate Bill SB 2 (1X) into law in April 2011.

SB 2 (1X) extends the original RPS goal from 20 percent of retail sales by the end of 2010 to 33 percent of retail sales by 2020 for all California investor-owned utilities (IOUs), electric service providers (ESPs) and the community choice aggregators (CCAs); it also obligates publicly owned utilities to meet these goals. In addition, the new law modifies many details of the program and creates portfolio content categories for RPS procurement. The California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) were tasked with implementing the expanded RPS. In December 2011, the CPUC issued a decision that addressed the criteria for inclusion in each of the new RPS portfolio content categories and the percentage of the annual procurement target that could be sourced from unbundled RECs. The use of unbundled renewable energy credits was capped at 25 percent of a utility's RPS requirement through December 31, 2013; this steps down to 15 percent in 2014 and 10 percent in 2017. The decision applies to contracts and ownership agreements entered into after June 1, 2010.