C Environmental Regulations

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

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1. ENVIRONMENTAL PROTECTION AGENCY REGULATIONS

Air and Climate Change Protection

PSE owns several thermal generation facilities, including a number of natural gas plants and a percentage of the coal-fired Colstrip generating plant in Montana. All of these facilities are governed by the Clean Air Act (CAA), and all have CAA Title V operating permits, which must be renewed every five years. This renewal process could result in additional costs to the plants. PSE continues to monitor the permit renewal process to determine the corresponding potential impact to the plants.

These facilities also emit greenhouse gases (GHG), and thus are also subject to any current or future GHG or climate change legislation or regulation. The GHG regulations that apply to these facilities are described in detail in the section of this appendix titled “Greenhouse Gas Emissions.”

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 supplies standards and criteria for the handling, storage and disposal of CCR. This includes regulations related to beneficial use, design, operation, closure, post-closure, groundwater monitoring and corrective action. 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.

The CCR rule requires significant changes to PSE’s Colstrip operations. Those changes were reviewed by PSE and the plant operator in the second quarter of 2015. PSE had previously recognized a legal obligation under the EPA rules to dispose of coal ash material at Colstrip in 2003. Due to the CCR rule, additional disposal costs were added to the Asset Retirement and Environmental Obligations (ARO), which is a closure and clean-up fund. In 2018, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) overturned certain provisions of the CCR rule in 2018 and remanded some of its provisions back to the EPA. As a result of that decision and certain other developments, on August 28, 2020, EPA published its final rule in the Federal Register (85 Fed. Reg. 53,516), entitled “Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals from Electric Utilities; A Holistic Approach to

Closure Part A: Deadline to Initiate Closure" (Part A Rule). The Part A Rule amends several regulatory provisions that govern coal combustion residuals and includes amendments that require certain CCR units (unlined or clay-lined surface impoundments and units failing the aquifer separation location restriction) to cease waste receipt and initiate closure "as soon as technically feasible" but no later than April 11, 2021. The final Part A Rule becomes effective on September 28, 2020.

Mercury and Air Toxics Standard (MATS)

The MATS rule established emissions limitations for hazardous air pollutants (HAPs) at coal-fired power plants, including limits 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).

On February 7, 2019, the EPA published a proposal to reconsider the "appropriate and necessary" finding that underpins MATS, but to leave the MATS regulation in place (i.e., to keep regulating HAP emissions from power plants).[1] The proposal would not weaken any pollution standards immediately; however, it would create a higher threshold for future regulations by narrowing the range of benefits the agency can consider when determining whether it is "appropriate and necessary" to devise new rules under Section 112 of the Clean Air Act.

Mercury control equipment has been installed at Colstrip and has operated at a level that meets the current Montana requirement. Compliance, based on a rolling twelve-month average, was first confirmed in January 2011, and PSE continues to meet the requirement. Further, Colstrip met the Mercury and Air Toxics Standard (MATS) limits for mercury and acid gases as of April 2017.

1 / *84 FR 2670 (Feb. 7, 2019).*

Water Protection

PSE facilities that discharge wastewater or storm water or store bulk petroleum products are governed by the Clean Water Act (federal and state) which includes the Oil Pollution Act amendments. This includes most generation facilities (and all of those with water discharges and some with bulk fuel storage), and many other facilities and construction projects depending on drainage, facility or construction activities, and chemical, petroleum and material storage.

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 program requires periodic reviews of progress in improving visibility.

In January 2017, the EPA provided revisions to the Regional Haze Rule which were published in the Federal Register. Among other things, these revisions delayed new Regional Haze reviews from 2018 to 2021; however, the end date for these reviews will remain 2028. In January 2018, the EPA announced that it would revisit certain aspects of these revisions, and PSE is unable to predict the outcome. Challenges to the 2017 Regional Haze Revision Rule are pending in abeyance in the D.C. Circuit, pending resolution of EPA's reconsideration of the rule.

Greenhouse Gas Emissions

Section 111(b) of the Clean Air Act

On October 25, 2015, EPA published a final rule combining its proposals for new, modified and reconstructed power plants into one rulemaking – collectively, the greenhouse gas New Source Performance Standards (NSPS) – which made several changes to the original proposal. The final rule separated standards for new power plants fueled by natural gas and coal from existing plants. New and reconstructed natural gas power plants can emit no more than 1,000 lbs of CO_2 per MWh, which is based on the latest CCCT technology. EPA did not finalize a standard for modified gas plants. New coal power plants can emit no more than 1,400 lbs CO_2 per MWh, whereas reconstructed and modified coal plants have higher emission limits based on their heat input. Coal plants would not specifically be required to employ carbon capture and sequestration (CCS), but CCS was reaffirmed by EPA as the Best System of Emissions Reduction (BSER) (i.e., the basis for establishing the emission limit for these units). The 111(b) NSPS standards are implemented by the states.

On December 20, 2018, EPA published a proposed rule that would revise the GHG NSPS for coal-fired units based on the agency's revised determination that CCS is not the BSER for newly constructed coal-fired units. Instead, EPA proposed that the BSER for these units is either supercritical or subcritical steam conditions (depending on the unit's heat input) combined with best operating practices. EPA did not propose any changes to the NSPS for gas-fired power plants. EPA accepted public comments on the proposed GHG NSPS revisions through March 18, 2019. As of today, there have been no further actions on this rulemaking (see EPA Docket EPA-HQ-OAR-2013-0495).

EPA Clean Power Plan (CPP)

On October 23, 2015, EPA published the Clean Power Plan (CPP), which was the final rule under section 111(d) of the Clean Air Act to regulate GHG emissions from existing power plants. The final rule included several changes from the proposed rule. Specifically, the EPA excluded energy efficiency from the "building blocks" states could use to meet the standard, leaving just three building blocks:

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

Soon after the EPA published the CPP, 27 states, along with several utilities, electric cooperatives and industry groups, challenged the rule's legality in the D.C. Circuit. On February 8, 2016, the U.S. Supreme Court stayed the effectiveness of the CPP pending the disposition of the challenges in the D.C. Circuit. On April 28, 2017, the D.C. Circuit granted EPA's request to put the lawsuits challenging the CPP on hold indefinitely without deciding the case (i.e., place the litigation in abeyance). That decision followed a request to halt the case from EPA, which was in the process of proposing to repeal and replace the CPP.

On October 16, 2017, EPA published a proposal to repeal the CPP based on a revised interpretation of section 111(d) of the Clean Air Act that requires emission standards to be based on pollution-control measures that can be applied to or at an existing source. This proposed interpretation of section 111(d) would mean that the CPP exceeds EPA's authority under the Clean Air Act by including the second and third building blocks: switching from coal to gas-powered generation and increasing generation from renewable sources. Because the CPP stated that the first building block (efficiency measures at coal plants) could not legally stand on its own if the other two blocks were repealed, EPA proposed that the entire CPP had to be repealed.

On August 31, 2018 the EPA published a replacement for the CPP, called the Affordable Clean Energy (ACE) Rule. The ACE Rule proposed to require modest efficiency improvements at some coal plants and give states more latitude to set their own carbon emission reduction standards, in contrast to the CPP, which pushed plant owners to invest in less-polluting sources. The ACE Rule also proposed changes to the test for whether physical or operational changes would trigger permitting requirements for a source under the New Source Review Program (NSR). The NSR revisions were proposed in light of the fact that some of the efficiency improvements required to comply with the GHG emission standard might trigger these permitting requirements under current law.

On July 8, 2019, EPA published the final ACE Rule, which repealed the CPP and replaced it with the more modest program that EPA had proposed; however, the final ACE Rule did not include the proposed changes to the NSR program. EPA plans to finalize those changes in a separate rulemaking at a later date. The CPP-replacement portion of the ACE Rule is structured similarly to EPA's proposal, except that it contains slightly less flexibility for states to decide how to regulate their sources than what was proposed. These limitations include a prohibition on using emissions averaging or trading as a mechanism for complying with standards of performance. Compliance is generally required by July 2024. PSE is evaluating the final ACE rule to determine its impact on operations.

2. STATE AND REGIONAL REGULATIONS

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) 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.

On July 25, 2017, the California Governor signed into law AB 398, extending through 2030 the cap-and-trade program authorized by AB 32. The new law requires CARB to develop a Scoping Plan which includes price ceilings and price containment points to further reduce California's emissions to 40 percent below 1990 levels by 2030. The law does not prescribe specific measures, except for approving the use of revenues from allowance auctions for investment in clean technologies.

CARB's Scoping Plan was released in December 2017 and called for cap-and-trade to be the backstop policy that drives complementary programs; these include zero emission vehicle regulations, the low carbon fuel standard and the state's mandate for 50 percent renewable electricity by 2030.[2]

Washington State

Washington Clean Energy Transformation Act

In May 2019, Washington State passed the 100 Percent Clean Electric Bill that supports Washington's clean energy economy and transition to a clean, affordable and reliable energy future. The Clean Energy Transformation Act requires all electric utilities to eliminate coal-fired generation from their allocation of electricity by December 31, 2025 and to be carbon neutral by January 1, 2030 through a combination of non-emitting electric generation, renewable generation, and/or alternative compliance options. It also makes it state policy that, by 2045, 100 percent of electric generation and retail electricity sales will come from renewable or non-emitting resources. Clean Energy Implementation plans are required every four years from each investor-owned utility (IOU). These implementation plans must propose interim targets for meeting the 2045 standard between 2030 and 2045 and lay out an actionable plan that the IOU intends to pursue to meet the standard. The Washington Utilities and Transportation Commission (WUTC) may approve, reject or recommend alterations to an IOU's plan.

In order to meet these requirements, the Act clarifies the WUTC's authority to consider and implement performance- and incentive-based regulation, multi-year rate plans and other flexible regulatory mechanisms where appropriate. The Act mandates that the WUTC accelerate depreciation schedules for coal-fired resources, including transmission lines, to December 31, 2025, or to allow IOUs to recover costs in rates for earlier closure of those facilities. IOUs will be allowed to earn a rate of return on certain Power Purchase Agreements (PPAs) and 36 months deferred accounting treatment for clean energy projects (including PPAs) identified in the utility's clean energy implementation plan.

IOUs are considered to be in compliance when the cost of meeting the standard or an interim target within the four-year period between plans equals a 2 percent increase in the weather-adjusted sales revenue to customers from the previous year. If relying on the cost cap exemption, IOUs must demonstrate that they have maximized investments in renewable resources and non-emitting generation prior to using alternative compliance measures.

2 / Note that since CARB released its scoping plan, the mandate has since been increased to 60 percent renewables by 2030 and 100 percent renewables by 2045. See California Renewable Portfolio Standard, infra, describing California's SB 100.

The law requires additional rulemaking by several Washington agencies for its measures to be enacted, and PSE is unable to predict the outcomes of the rulemakings at this time. PSE intends to seek recovery of any costs associated with the clean energy legislation through the regulatory process.

Greenhouse Gas Emissions Performance Standard

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

The current EPS, set in 2018, is 925 lbs of CO_2 emissions per MWh, and the EPS is reviewed every five years.

Carbon Dioxide Mitigation Program

In 2004, the Washington State legislature passed Substitute House Bill 3141, later codified in RCW 80.70. The law requires new or modified 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 (CAR)

Washington State adopted the CAR in September 2016, which attempts to reduce greenhouse gas emissions from “covered entities” located within Washington state. Included under the new rule are large manufacturers, petroleum producers and natural gas utilities, including PSE. The CAR sets a cap on emissions associated with covered entities which decreases over time, approximately 5.0 percent every three years. Entities must reduce their carbon emissions or purchase emission reduction units (ERUs), as defined under the rule, from others.

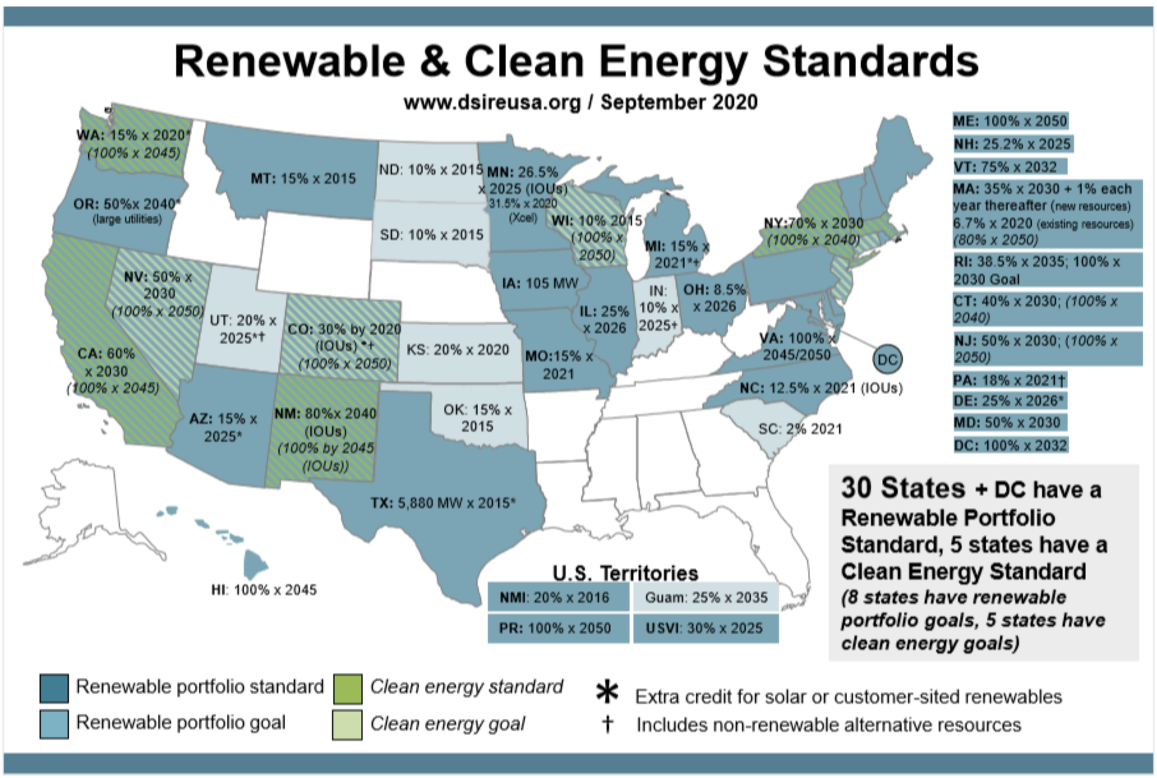
In September 2016, PSE, along with Avista Corporation, Cascade Natural Gas Corporation and NW Natural, filed a lawsuit in the U.S. District Court for the Eastern District of Washington challenging the CAR. In September 2016, the four companies filed a similar challenge to the CAR in Thurston County Superior Court. In March 2018, the Thurston County Superior Court invalidated the CAR. The Department of Ecology appealed the Superior Court decision in May 2018. As a result of the appeal, direct review to the Washington State Supreme Court was granted and oral argument was held on March 16, 2019. In January 2020, the Washington Supreme Court affirmed that CAR is not valid for “indirect emitters” meaning it does not apply to the sale of natural gas for use by customers. The court ruled, however, that the rule can be severed and is valid for direct emitters including electric utilities with permitted air emission sources, but remanded the case back to the Thurston County to determine which parts of the rule survive. Meanwhile, the federal court litigation has been held in abeyance pending resolution of the state case.

Renewable Portfolio Standards (RPS)

Renewable portfolio standards require utilities to obtain a specific portion of their electricity from renewable energy resources. Of the 11 interconnected Western 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, 9 percent for 2016-2019 and 15 percent starting in 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.[3]

Figure C-1: RPS Requirements by State



3 / 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	ELIGIBLE RENEWABLE ENERGY
Arizona	15% by 2025	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	60% by 2030 100% by 2045	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	30% by 2020 (IOUs); Co-ops serving >100,000 meters: 20% by 2020; Co-ops serving <100,000 meters: 10% by 2020; Municipal utilities serving >40,000 customers: 10% by 2020 100% by 2050	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	N/A
Montana	15% by 2015	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	80% by 2040 (IOUs) 100% by 2045 (IOUs)	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	50% by 2030 and thereafter Goal: 100% by 2050	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	50% by 2040 (large IOUs); 5-25% by 2025 (other utilities)	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	No requirement Goal of 20% by 2025	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	RPS: 15% by 2020 and all cost-effective conservation CETA: 80% by 2030 and 100% by 2045	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	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

California has one of the most aggressive RPS mandates in the region. The size and aggressiveness of its mandate make it the region's primary driver of renewable resource availability and cost, REC product availability and cost, and transmission and integration.

The state's program was originally established in 2002, and its goals have been extended and accelerated several times since then.

- When Senate Bill SB X 1-2 was signed into law in April 2011, the renewable energy goal was increased from 20 percent to 33 percent of retail sales by 2020. This applies to all California investor-owned utilities, electric service providers (ESPs), community choice aggregators (CCAs) and publicly owned utilities.

- When Senate Bill 350 was signed into law in 2015, the renewable requirement for retail sellers and publicly owned utilities was increased to 50 percent by 2030.

- When Senate Bill 100 was signed into law in 2018, California committed to phasing out all fossil fuels from the state's electricity sector by 2045. This goal requires renewable energy and zero-carbon resources to supply 100 percent of electric sales to end-use customers by 2045.

Under Senate Bill SB X 1-2, 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.