2021 PSE Integrated Resource Plan

Appendices B-M

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PUGET SOUND ENERGY

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B Legal Requirements

This appendix identifies where each of the regulatory requirements for the electric and natural gas integrated resource plans is addressed within the IRP and reports on the progress of the 2017 IRP electric and natural gas utility action plans, the last IRP filed. It also delivers two additional reports.

Contents

1. CLEAN ENERGY TRANSFORMATION ACT (CETA)

On May 7, 2019, Governor Jay Inslee signed into law the Clean Energy Transformation Act (CETA), which commits Washington to an electricity supply free of greenhouse gas emissions by 2045. The CETA applies to all electric utilities serving retail customers in Washington (such as PSE) and sets specific milestones to reach the required 100 percent clean electricity supply. The first milestone is October 1, 2021 when PSE must prepare and publish a clean energy implementation plan (CEIP) with its own targets for energy efficiency, demand response and renewable energy. The draft CEIP filing is due on August 15, 2021.

By the end of 2025, PSE must eliminate coal-fired electricity from its state portfolios. The first clean energy standard applies in 2030. The 2030 standard is greenhouse gas neutral, which means that PSE will have the flexibility to use limited amounts of electricity from greenhouse gas emitting resources if those resources are offset by other actions, such as procurement of renewable energy credits. By 2045, PSE must supply customers in Washington with electricity that is 100 percent renewable or non-emitting, with no provision for offsets.

Coal Phase-out Requirement

The CETA requires PSE to eliminate coal-fired resources from its allocation of electricity sold to retail customers in its service territory by December 31, 2025. For the purposes of this standard, a “coal-fired resource” does not include:

- an electric generating facility that is subject to an obligation to meet the state's Greenhouse Gas Emissions Performance Standard (i.e., the TransAlta Centralia Coal Plant); or
- an electric generation facility that is included as part of certain limited duration wholesale power purchases, not to exceed one month, for which the source of the power is not known at the time of entry into the transaction to procure the electricity (i.e., short-term transactions of undifferentiated electricity).

The Washington Utilities and Transportation Commission (Commission) must accelerate depreciation for any coal-fired resource owned by PSE and is allowed to accelerate depreciation for any qualified transmission line to no later than December 31, 2025. Additionally, the Commission must allow in rates prudently incurred undepreciated investments in a fossil-fuel generating resource that has been retired from service under specific conditions.

Greenhouse Gas Neutral Standard (January 1, 2030 - December 31, 2044)

The CETA will require PSE to make all retail sales of electricity to Washington customers greenhouse gas neutral for multi-year compliance periods beginning January 1, 2030, and ending December 31, 2044. To achieve compliance with this standard, PSE must:

- pursue all cost-effective, reliable, and feasible conservation and efficiency resources and demand response resources to reduce or manage electric retail load; and
- use electricity from renewable resources and non-emitting electric generation (or alternative compliance options, discussed below) in an amount equal to 100 percent of PSE's average annual retail electric load over each multiyear compliance period.

All renewable resources used to meet the compliance obligation must be verified using renewable energy credits and must be tracked and retired in the tracking system selected by the Department of Commerce. Non-emitting generation resources used to meet the obligation must be generated during the compliance period and must be verified by documentation that PSE owns the non-power attributes of the electricity.

In complying with the greenhouse gas neutral standard and clean energy standard, PSE may not use hydroelectric generation that requires new diversions, impoundments, bypass reaches or expansion of existing reservoirs, unless otherwise required for the operation of a pumped storage facility. PSE may, however, make efficiency or other improvements to its existing facilities and may install hydroelectric generation in pipes, culverts, irrigation canals and other manmade waterways. Nothing in the greenhouse gas neutral or clean energy standards prohibits PSE from purchasing from or exchanging power with the Bonneville Power Administration (BPA).

Alternative Compliance Option

PSE may satisfy up to 20 percent of the greenhouse gas neutral standard with an alternative compliance option for the greenhouse gas neutral standard compliance period beginning January 1, 2030 and ending December 31, 2044. An alternative compliance option includes any combination of the following:

- making an alternative compliance payment in an amount equal to the administrative penalty discussed below;
- purchasing unbundled renewable energy credits;
- investing in energy transformation projects associated with the consumption of energy in Washington and that meet criteria and quality standards developed by the Department of Ecology, in consultation with the Department of Commerce and the Commission; or
- using electricity from an energy recovery facility using municipal solid waste as the principal fuel source, where the facility was constructed prior to 1992 and is in compliance with federal and state air quality standards.

Administrative Penalty

If PSE were to fail to comply with the coal phase-out or carbon neutral standards, PSE must pay an administrative penalty equal to the product of 1) $100/MWh of emitting or unspecified electric generation used to meet PSE's retail electric load times 2) the following multipliers

- 1.5 for coal-fired resources;
- 0.84 for gas-fired peaking power plants; and
- 0.60 for gas-fired combined-cycle power plants.

The penalty is adjusted for inflation, beginning in 2027. Beginning in 2040, the Commission may increase the penalty for PSE to accelerate compliance.

The Commission may relieve PSE of its penalty obligation under the greenhouse gas neutral standard if it finds that PSE's compliance is likely to result in conflicts with or compromises to its obligation to comply with North American Electric Reliability Corporation (NERC) reliability standards, violate prudent utility practice for assuring resource adequacy, compromise the power quality or integrity of its system, or due to factors reasonably outside PSE's control. Additionally, the Governor may waive a penalty by declaring an energy emergency under current law, if the Department of Commerce's report demonstrates adverse system reliability impacts due to implementation of the coal phase-out or greenhouse gas neutral standards.

Clean Energy Standard (Beginning January 1, 2045)

By January 1, 2045, PSE must meet 100 percent of its retail electric load to Washington customers using non-emitting electric generation and electricity from renewable resources. The Commission, the Department of Commerce, the Energy Facility Site Evaluation Council, the Department of Ecology and all other state agencies must incorporate this standard into all relevant planning and use all statutory programs to achieve the standard.

In planning to meet projected demand, PSE must, consistent with the requirements of the Energy Independence Act, pursue all cost-effective, reliable, and feasible conservation efficiency resources, and demand response. In making new investments, PSE must, and to the maximum extent feasible, 1) achieve targets at the lowest reasonable cost; 2) consider acquisition of surplus renewable resources; and 3) rely on renewable resources and energy storage in the acquisition of new resources.

Energy Resource Planning

Integrated Resource Plans and the Clean Energy Action Plan

The CETA requires PSE to consider the following elements in its Integrated Resource Plans:

- an assessment and 10-year forecast of the availability of regional generation and transmission capacity on which PSE may rely to provide and deliver electricity to its customers;
- a determination of resource adequacy metrics for the resource plan consistent with the forecasts;
- a forecast of distributed energy resources that may be installed by PSE's customers and an assessment of their effect on PSE's load and operations;
- an assessment, informed by the Department of Health's Cumulative Impact Analysis, "of energy and nonenergy benefits and reductions of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits, costs and risks; and energy security and risk;";and
- a 10-Year Clean Energy Action Plan for implementing the coal phase-out standard, the greenhouse gas neutral standard, and the clean energy standard at the lowest reasonable cost, and at an acceptable resource adequacy standard, that identifies the specific actions to be taken by PSE consistent with the long-range IRP.

The CETA requires PSE to consider the social cost of greenhouse gas emissions when developing its Integrated Resource Plan and Clean Energy Action Plan. PSE must incorporate the social cost of greenhouse gas emissions as a cost adder when evaluating and selecting conservation policies, programs and targets and evaluating and selecting intermediate-term and long-term resource options. The cost of greenhouse gas emissions resulting from the generation of electricity is equal to the cost per metric ton of carbon dioxide equivalent emissions, using the 2.5 percent discount rate published by the United States government Interagency Working Group on the Social Cost of Greenhouse Gases.

Clean Energy Implementation Plan

By January 1, 2022, and every four years thereafter, the CETA requires PSE to develop and submit to the Commission 1) a four-year Clean Energy Implementation Plan for the greenhouse gas neutral standard and clean energy standard and 2) proposed interim targets for meeting the greenhouse gas neutral standard during the years prior to January 1, 2030, and for the period beginning on January 1, 2030 and ending on December 31, 2044.

The Clean Energy Implementation Plan must

- be informed by PSE's Clean Energy Action Plan and
- identify specific actions to be taken by PSE over the next four years, consistent with PSE's Integrated Resource Plan and resource adequacy requirements, that demonstrate progress toward meeting (i) the interim targets proposed along with the clean energy implementation plan, (ii) the greenhouse gas neutral standard, and (iii) the clean energy standard.

The specific actions identified in the Clean Energy Implementation Plan must be informed by PSE's historic performance under median water conditions and resource capability and its participation in centralized markets. In identifying specific actions in its Clean Energy Implementation Plan, PSE may also take into consideration any significant and unplanned loss or addition of load it experiences.

The Commission, after a hearing, must by order approve, reject, or approve with conditions PSE's Clean Energy Implementation Plan and interim targets. The Commission may, in its order, recommend or require more stringent targets than those proposed by PSE. The Commission may periodically adjust or expedite timelines if it can be demonstrated that the targets or timelines can be achieved in a manner consistent with the following:

1. maintaining and protecting the safety, reliable operation, and balancing of the electric system;
2. planning to meet the standards at the lowest reasonable cost, considering risk;
3. ensuring that all customers are benefiting from the transition to clean energy; and
4. ensuring that no customer or class of customers is unreasonably harmed by any resulting increases in the cost of PSE-supplied electricity as may be necessary to comply with the standards.

CETA Rulemakings

The Commission finished three major CETA rulemaking efforts at the end of 2020 and issued final rules on December 29, 2020. The new CETA rules set up a procedural framework within which utilities must plan for and acquire clean energy resources to comply with CETA. The new rules make considerable changes to existing rules for electric Integrated Resource Plans, which are detailed in Tables B-3 and B-5 below.

2. REGULATORY REQUIREMENTS

Figure B-1 lists the statutory requirements in the CETA that apply to electric IRPs. Figure B-2 lists the regulatory requirements for electric utilities codified in WAC RCW 19.280.100. Figure B-3 lists the regulatory requirements previously codified in WAC 480-100-238, now included in WAC 480-100-620 and WAC 480-100-625, that apply to electric integrated resource plans.[1] B-4 lists the regulatory requirements currently in effect in WAC 480-90-238 that apply to natural gas integrated resource plans. These tables identify the chapters and appendices of this plan that address each requirement. Figure B-5 details an additional condition pursuant to WUTC Order 01, dated April 13, 2017 in PSE's 2017 docket. Other conditions in Order 01 were addressed in the 2017 IRP. Figure B-6 details natural gas utility requirements pursuant to HB 1257.[2]

Figure B-1: Electric Utility Integrated Resource Plan Regulatory Requirements in the CETA

Statutory or Regulatory Requirement	Chapter and/or Appendix
RCW 19.280.030 (1) (a) A range of forecasts, for at least the next ten years or longer, of projected customer demand which takes into account econometric data and customer usage.	Chapter 5, Key Analytical Assumptions Chapter 6, Demand Forecasts Appendix F, Demand Forecasting Models
RCW 19.280.030 (1) (b) An assessment of commercially available conservation and efficiency resources. Such assessment may include, as appropriate, opportunities for development of combined heat and power as an energy and capacity resource, demand response and load management programs, and currently employed and new policies and programs needed to obtain the conservation and efficiency resources.	Chapter 8, Electric Analysis Appendix E, Conservation Potential Assessment and Demand Response Assessment Appendix H, Electric Analysis Inputs and Results
RCW 19.280.030 (1) (c) An assessment of commercially available, utility scale renewable and nonrenewable generating technologies including a comparison of the benefits and risks of purchasing power or building new resources.	Chapter 4, Planning Environment Chapter 7, Resource Adequacy Analysis Chapter 8, Electric Analysis Appendix D, Electric Resources and Alternatives Appendix H, Electric Analysis Inputs and Results

1 / The Commission adopted new IRP rules on December 28, 2020, which took effect December 31, 2020. In adopting new IRP rules, the Commission intends to replace the rules previously codified in WAC 480-100-238. The process to repeal WAC 480-100-238 is underway at the Commission as an expedited, emergency rulemaking.
2 / The Commission anticipates rulemaking in 2021 to develop rules for natural gas utilities pursuant to HB 1257.

Statutory or Regulatory Requirement	Chapter and/or Appendix
RCW 19.280.030 (1) (d) A comparative evaluation of renewable and nonrenewable generating resources, including transmission and distribution delivery costs, and conservation and efficiency resources using "lowest reasonable cost" as a criterion.	Chapter 3, Resource Plan Decisions Chapter 8, Electric Analysis Chapter 10, Delivery System Planning Appendix D, Electric Resources and Alternatives Appendix E, Conservation Potential Assessment and Demand Response Assessment Appendix H, Electric Analysis Inputs and Results Appendix J, Regional Transmission Resources
RCW 19.280.030 (1) (e) An assessment of methods, commercially available technologies, or facilities for integrating renewable resources, and addressing overgeneration events, if applicable to the utility's resource portfolio.	Chapter 5, Key Analytical Assumptions Chapter 8, Electric Analysis Appendix D, Electric Resources and Alternatives Appendix H, Electric Analysis Inputs and Results
RCW 19.280.030 (1) (f) An assessment and ten-year forecast of the availability of regional generation and transmission capacity on which the utility may rely to provide and deliver electricity to its customers..	Chapter 3, Resource Plan Decisions Chapter 7, Resource Adequacy Analysis Chapter 8, Electric Analysis Appendix J, Regional Transmission Resources
RCW 19.280.030 (1) (g) A determination of resource adequacy metrics for the resource plan consistent with the forecasts.	Chapter 1, Executive Summary Chapter 7, Resource Adequacy Analysis Chapter 8, Electric Analysis Appendix G, Electric Analysis Models Appendix H, Electric Analysis Inputs and Results
RCW 19.280.030 (1) (h) A forecast of distributed energy resources that may be installed by the utility's customers and an assessment of their effect on the utility's load and operations.	Appendix E, Conservation Potential Assessment and Demand Response Assessment Chapter 5, Key Analytical Assumptions
RCW 19.280.030 (1) (i) An identification of an appropriate resource adequacy requirement and measurement metric consistent with prudent utility practice in implementing sections 3 through 5 of CETA.	Chapter 7, Resource Adequacy Analysis Chapter 8, Electric Analysis Appendix G, Electric Analysis Models

Statutory or Regulatory Requirement	Chapter and/or Appendix
RCW 19.280.030 (1) (j) The integration of the demand forecasts, resource evaluations, and resource adequacy requirement into a long-range assessment describing the mix of supply side generating resources and conservation and efficiency resources that will meet current and projected needs, including mitigating overgeneration events and implementing sections 3 through 5 of CETA, at the lowest reasonable cost and risk to the utility and its customers, while maintaining and protecting the safety, reliability operation, and balancing of its electric system.	Chapter 1, Executive Summary Chapter 2, Clean Energy Action Plan Chapter 3, Resource Plan Decisions Chapter 5, Key Analytical Assumptions
RCW 19.280.030 (1) (k) An assessment, informed by the cumulative impact analysis conducted under section 24 of CETA of: Energy and nonenergy benefits and reductions of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits, costs, and risks, and energy security and risk.	Chapter 2, Clean Energy Action Plan Appendix K, Economic, Health and Environmental Benefits Assessment of Current Conditions
RCW 19.280.030 (1) (l) A ten-year clean energy action plan for implementing sections 3 through 5 of CETA at the lowest reasonable cost, and at an acceptable resource adequacy standard, that identifies the specific actions to be taken by the utility consistent with the long-range integrated resource plan.	Chapter 2, Clean Energy Action Plan
RCW 19.208.030 (3)(a) An electric utility shall consider the social cost of greenhouse gas emissions, as determined by the commission for investor-owned utilities, pursuant to section 15 of CETA when developing integrated resource plans and clean energy action plans.	Chapter 5, Key Analytical Assumptions Chapter 8, Electric Analysis Appendix H, Electric Analysis Inputs and Results

Figure B-2: Electric Utility Integrated Resource Plan Regulatory Requirements Codified in WAC RCW 19.280.100

Statutory or Regulatory Requirement	Discussion
RCW 19.280.100. (2) (a) Identify the data gaps that impede a robust planning process as well as any upgrades, such as but not limited to advanced metering and grid monitoring equipment, enhanced planning simulation tools, and potential cooperative efforts with other utilities in developing tools needed to obtain data that would allow the electric utility to quantify the locational and temporal value of resources on the distribution system;	Chapter 2, Clean Energy Action Plan Appendix M, Delivery System 10-Year Plan
RCW 19.280.100. (2) (b) Propose monitoring, control, and metering upgrades that are supported by a business case identifying how those upgrades will be leveraged to provide net benefits for customers;	Chapter 2, Clean Energy Action Plan Appendix M, Delivery System 10-Year Plan
RCW 19.280.100. (2) (c) Identify potential programs that are cost-effective and tariffs to fairly compensate customers for the actual monetizable value of their distributed energy resources, including benefits and any related implementation and integration costs of distributed energy resources, and enable their optimal usage while also ensuring reliability of electricity service, such as programs benefiting low-income customers;	Programs will be identified through the CEIP process and through engagement with the Equity Advisory Group. PSE is pursuing an Alternative Pricing pilot.
RCW 19.280.100. (2) (d) Forecast, using probabilistic models if available, the growth of distributed energy resources on the utility's distribution system;	Appendix E, Conservation Potential Assessment and Demand Response Assessment

Statutory or Regulatory Requirement	Discussion
RCW 19.280.100. (2) (e) Provide, at a minimum, a ten-year plan for distribution system investments and an analysis of nonwires alternatives for major transmission and distribution investments as deemed necessary by the governing body, in the case of a consumer-owned utility, or the commission, in the case of an investor-owned utility. This plan should include a process whereby near-term assumptions, any pilots or procurements initiated in accordance with subsection (3) of this section or data gathered via current market research into a similar type of utility or other cost/benefit studies, regularly inform and adjust the long-term projections of the plan. The goal of the plan should be to provide the most affordable investments for all customers and avoid reactive expenditures to accommodate unanticipated growth in distributed energy resources. An analysis that fairly considers wire-based and nonwires alternatives on equal terms is foundational to achieving this goal. The electric utility should be financially indifferent to the technology that is used to meet a particular resource need. The distribution system investment planning process should utilize a transparent approach that involves opportunities for stakeholder input and feedback. The electric utility must identify in the plan the sources of information it relied upon, including peer-reviewed science. Any cost-benefit analysis conducted as part of the plan must also include at least one pessimistic scenario constructed from reasonable assumptions and modeling choices that would produce comparatively high probable costs and comparatively low probable benefits, and at least one optimistic scenario constructed from reasonable assumptions and modeling choices that would produce comparatively low probable costs and comparatively high probable benefits;	Chapter 4, Planning Environment Appendix A, Public Participation Appendix M, Delivery System 10-Year Plan

Statutory or Regulatory Requirement	Discussion
RCW 19.280.100. (2) (f) Include the distributed energy resources identified in the plan in the electric utility's integrated resource plan developed under this chapter. Distribution system plans should be used as inputs to the integrated resource planning process. Distributed energy resources may be used to meet system needs when they are not needed to meet a local distribution need. Including select distributed energy resources in the integrated resource planning process allows those resources to displace or delay system resources in the integrated resource plan;	Chapter 2, Clean Energy Action Plan Chapter 5, Key Analytic Assumptions Appendix M, Delivery System 10-Year Plan
RCW 19.280.100. (2) (g) Include a high level discussion of how the electric utility is adapting cybersecurity and data privacy practices to the changing distribution system and the internet of things, including an assessment of the costs associated with ensuring customer privacy; and	Chapter 2, Clean Energy Action Plan Appendix M, Delivery System 10-Year Plan
RCW 19.280.100. (2) (h) Include a discussion of lessons learned from the planning cycle and identify process and data improvements planned for the next cycle.	Appendix M, Delivery System 10-Year Plan
RCW 19.280.100. (3) To ensure that procurement decisions are based on current cost and performance data for distributed energy resources, a utility may procure cost-effective distributed energy resource needs as identified in any distributed energy resources plan through a process that is price-based and technology neutral. Electric utilities should consider using competitive procurements tailored to meet a specific need, which may increase the utility's ability to identify the lowest cost and most efficient means of meeting distribution system needs. If the projected cost of a procurement is more than the calculated system net benefit of the identified distributed energy resources, the governing body, in the case of a consumer-owned utility, or the commission, in the case of an investor-owned utility, may approve a pilot process by which the electric utility will gain a better understanding of the costs and benefits of a distributed energy resource or resources.	Further work will be done through the Clean Energy Implementation Plan

Figure B-3: Electric Utility Integrated Resource Plan Regulatory Requirements Codified in WAC 480-100-620 and 480-100-625

Statutory or Regulatory Requirement	Chapter and/or Appendix
WAC 480-100-620 (2) A range of forecasts of projected customer demand that reflect the effect of economic forces on the consumption of electricity and that address changes in the number, type and efficiency of electrical end-uses.	Chapter 5, Key Analytical Assumptions Chapter 6, Demand Forecasts Appendix F, Demand Forecasting Models
WAC 480-100-620 (3) (a) Assessments of a variety of distributed energy resources. These assessments must incorporate nonenergy costs and benefits.	Chapter 2, Clean Energy Action Plan Chapter 3, Resource Plan Decisions Chapter 5, Key Analytical Assumptions Chapter 8, Electric Analysis Appendix M, Delivery System 10-Year Plan
WAC 480-100-620 (3) (b) (i) an assessment of currently employed and potential policies and programs needed to obtain all cost-effective conservation, efficiency and load management improvements.	Chapter 8, Electric Analysis Appendix E, Conservation Potential Assessment and Demand Response Assessment
WAC 480-100-620 (3) (b) (ii) Assess currently employed and new policies and programs needed to obtain all cost-effective demand response.	Chapter 3, Resource Plan Decisions Chapter 5, Key Analytical Assumptions Chapter 8, Electric Analysis Appendix M, Delivery System 10-Year Plan Appendix E, Conservation Potential Assessment and Demand Response Assessment

Statutory or Regulatory Requirement	Chapter and/or Appendix
WAC 480-100-620 (3) (b) (iii) Include distributed energy programs and mechanisms identified pertaining to energy assistance.	By July 31, 2021, PSE will provide an assessment to the Department of Commerce of mechanisms pertaining to energy assistance, as well as progress toward meeting customer energy assistance need. Existing PSE programs include bill assistance and weatherization services. Currently, PSE does not have any distributed energy resource (DER) programs as part of its energy assistance strategy. However, in future years, there may be programs and mechanisms that could be used to meet customer energy assistance need, and those programs will be considered and incorporated into the IRP as indicated in draft WAC 480-100-610(3). In examining energy assistance need, PSE will continue review of its recently completed Low-income Needs Assessment. In addition, PSE will conduct further qualitative research and analysis to better understand the barriers to serving low-income customers in order to encourage further participation of income-eligible households in the weatherization and bill assistance programs.
WAC 480-100-620 (3) (b) (iv) Assess other distributed energy resources that may be installed by the utility or the utility's customers including energy storage, electric vehicles, and PV.	Chapter 2, Clean Energy Action Plan Chapter 3, Resource Plan Decisions Chapter 5, Key Analytical Assumptions Chapter 8, Electric Analysis Appendix M, Delivery System 10-Year Plan
WAC 480-100-620 (4) An assessment of a wide range of commercially available generating and nonconventional technologies.	Chapter 5, Key Analytical Assumptions Chapter 8, Electric Analysis Appendix D, Electric Resources and Alternatives Appendix H, Electric Analysis Inputs and Results
WAC 480-100-620 (5) An assessment of methods, commercially available technologies, or facilities for integrating renewable resources and addressing overgeneration events, if applicable to the utility's resource portfolio.	Chapter 8, Electric Analysis Appendix D, Electric Resources and Alternatives Appendix H, Electric Analysis Inputs and Results

Statutory or Regulatory Requirement	Chapter and/or Appendix
WAC 480-100-620 (6) An assessment of regional generation and transmission capacity. Must include the utility's existing transmission capabilities, and future resource needs. Must identify the general location and extent of transfer capability limitations on its transmission network.	Appendix J, Regional Transmission Resources Appendix M, Delivery System 10-Year Plan
WAC 480-100-620 (7) A comparative evaluation of all identified resources and potential changes to existing resources for achieving the clean energy transformation standards in WAC 480-100-610 at the lowest reasonable cost.	Chapter 3, Resource Plan Decisions Chapter 8, Electric Analysis Appendix D, Electric Resources and Alternatives Appendix E, Conservation Potential Assessment and Demand Response Assessment Appendix H, Electric Analysis Inputs and Results Appendix J, Regional Transmission Resources Appendix M, Delivery System 10-Year Plan
WAC 480-100-620 (8) An assessment and determination of resource adequacy metrics and an appropriate resource adequacy requirement and measurement metrics consistent with CETA.	Chapter 7, Resource Adequacy Analysis
WAC 480-100-620 (9) An assessment of energy and nonenergy benefits and reductions of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits, costs, and risks; and energy security risk, informed by the cumulative impact analysis conducted by the department of health.	Appendix K, Economic, Health and Environmental Benefits Assessment of Current Conditions
WAC 480-100-620 (10) (a) At least one scenario must describe the lowest reasonable cost and reasonably available portfolio that the utility would have implemented if not for CETA requirements in RCW 19.405.040 and 19.405.050.	Chapter 5, Key Analytical Assumptions Chapter 8, Electric Analysis Appendix H, Electric Analysis Inputs and Results
WAC 480-100-620 (10) (b) At least one scenario must be a future climate change scenario.	Chapter 5, Key Analytical Assumptions Chapter 8, Electric Analysis Appendix H, Electric Analysis Inputs and Results
WAC 480-100-620 (10) (c) At least one sensitivity must be a maximum customer benefit scenario. The sensitivity should model the maximum amount of customer benefits described in RCW 19.405.040(8).	Chapter 5, Key Analytical Assumptions Chapter 8, Electric Analysis Appendix H, Electric Analysis Inputs and Results

Statutory or Regulatory Requirement	Chapter and/or Appendix
WAC 480-100-620 (11) Integration of the demand forecasts and resource evaluations into a long-range integrated resource plan describing the mix of resources that meet current and projected resource needs.	Chapter 2, Clean Energy Action Plan Chapter 3, Resource Plan Decisions Chapter 6, Demand Forecasts Appendix F, Demand Forecasting Models
WAC 480-100-620 (11) (a) A narrative description of decisions made including how the IRP expects to achieve the clean energy transformation standards at lowest cost.	Chapter 2, Clean Energy Action Plan Chapter 3, Resource Plan Decisions
WAC 480-100-620 (11) (b) A narrative description of decisions made including how the IRP expects to serve utility load, based on hourly data with the output of the utility's owned resources, market purchases, and power purchase agreements net of any off-system sales.	Chapter 2, Clean Energy Action Plan Chapter 3, Resource Plan Decisions Chapter 5, Key Analytical Assumptions Chapter 8, Electric Analysis
WAC 480-100-620 (11) (c) A narrative description of decisions made including how the IRP expects to include all cost-effective, reliable and feasible conservation and efficiency and demand response resources.	Chapter 2, Clean Energy Action Plan Chapter 3, Resource Plan Decisions Chapter 5, Key Analytical Assumptions Chapter 8, Electric Analysis
WAC 480-100-620 (11) (d) A narrative description of decisions made including how the IRP expects to consider acquisition of existing renewable resources.	Chapter 2, Clean Energy Action Plan Chapter 3, Resource Plan Decisions Chapter 5, Key Analytical Assumptions Chapter 8, Electric Analysis
WAC 480-100-620 (11) (e) A narrative description of decisions made including how the IRP expects in the acquisition of new resources, to rely on renewable resources and energy storage in so far as doing so is at the lowest reasonable cost.	Chapter 2, Clean Energy Action Plan Chapter 3, Resource Plan Decisions Chapter 5, Key Analytical Assumptions Chapter 8, Electric Analysis
WAC 480-100-620 (11) (f) A narrative description of decisions made including how the IRP expects to maintain and protect the safety, reliable operation, and balancing of the utility's electric system.	Chapter 2, Clean Energy Action Plan Chapter 3, Resource Plan Decisions Chapter 5, Key Analytical Assumptions Chapter 8, Electric Analysis
WAC 480-100-620 (11) (g) A narrative description of decisions made including how the IRP expects to achieve the requirements in WAC 480-100-610 (4) (c) including the long-term strategy and interim steps the utility will take to equitably distribute benefits and reduce burdens for highly impacted communities and vulnerable populations; and the estimated degree to which benefits will be equitably distributed and burdens reduced over the planning horizon.	Chapter 2, Clean Energy Action Plan

Statutory or Regulatory Requirement	Chapter and/or Appendix
WAC 480-100-620 (11) (h) A narrative description of decisions made including how the IRP expects to assess the environmental health impacts to highly impacted communities.	Appendix K, Economic, Health and Environmental Benefits Assessment of Current Conditions
WAC 480-100-620 (11) (i) A narrative description of decisions made including how the IRP expects to analyze and consider combinations of distributed energy resource costs, benefits, and operational characteristics to meet system needs.	Chapter 2, Clean Energy Action Plan Chapter 3, Resource Plan Decisions Chapter 5, Key Analytical Assumptions Chapter 8, Electric Analysis
WAC 480-100-620 (11) (j) A narrative description of decisions made including how the IRP expects to incorporate the social cost of greenhouse gas emissions as a cost adder.	Appendix G, Electric Analysis Models Chapter 5, Key Analytical Assumptions
WAC 480-100-620 (12) A ten-year clean energy action plan for implementing the clean energy standards at the lowest reasonable cost; informed by the utility's ten year cost-effective conservation potential assessment; identifies how the utility will meet the requirements in WAC 480-100-610 (4)(c); establishes a resource adequacy requirement; identifies cost-effective demand response and load management programs; identifies renewable resources, nonemitting electric generation and distributed energy resources; identifies any need to develop new, or to expand or upgrade existing, bulk transmission and distribution facilities; identifies the nature and possible extent to which the utility will rely on alternative compliance options; and incorporates the social cost of greenhouse gas emissions as a cost adder.	Chapter 2, Clean Energy Action Plan
WAC 480-100-620 (13) Include an analysis and summary of the avoided cost estimate for energy, capacity, transmission, distribution, and greenhouse gas emissions costs. Must list nonenergy costs and benefits addressed in the IRP and specify if they accrue to the utility, customers, participants, vulnerable populations, highly impacted communities or the general public.	Appendix H, Electric Analysis Inputs and Results Data input files are available on pse.com/irp and referenced in Appendix H.
WAC 480-100-620 (14) Data input files made available to the Commission in native format as an appendix to the IRP.	Appendix H, Electric Analysis Inputs and Results Data input files are available on pse.com/irp and referenced in Appendix H.
WAC 480-100-620 (15) Information and analysis that will be used to inform annual filings under Chapter 480-106 WAC related to qualifying facilities.	Appendix H, Electric Analysis Inputs and Results Data input files are available on pse.com/irp and referenced in Appendix H.

Statutory or Regulatory Requirement	Chapter and/or Appendix
WAC 480-100-620 (16)A summary of substantive changes to modeling methodologies or inputs that result in changes to the utility's resource need, as compared to the previous IRP.	Chapter 5, Key Analytical Assumptions
WAC 480-100-620 (17) A summary of public comments received during IRP development and utility responses.	Appendix A, Public Participation
WAC 480-100-625 (1) Timing. Unless otherwise ordered by the commission, each electric utility must file an IRP with the Commission by January 1, 2021, and every five years thereafter.	2021 Integrated Resource Plan Work Plan filed with the WUTC April, 2020, and Updated Work Plan filed May 15, 2020; July 8, 2020; September 17, 2020; October 26, 2020; and November 19, 2020.

Figure B-4: Natural Gas Utility Integrated Resource Plan Regulatory Requirements Codified in WAC 480-90-238

Statutory or Regulatory Requirement	Chapter and/or Appendix
WAC 480-90-238 (3) (a) A range of forecasts of future natural gas demand in firm and interruptible markets for each customer class that examine the effect of economic forces on the consumption of natural gas and that address changes in the number, type and efficiency of natural gas end-uses.	Chapter 5, Key Analytical Assumptions Chapter 6, Demand Forecasts Appendix F, Demand Forecasting Models
WAC 480-90-238 (3) (b) An assessment of commercially available conservation, including load management, as well as an assessment of currently employed and new policies and programs needed to obtain the conservation improvements.	Chapter 9, Natural Gas Analysis Appendix I, Natural Gas Analysis Results Appendix E, Conservation Potential Assessment and Demand Response Assessment
WAC 480-90-238 (3) (c) An assessment of conventional and commercially available nonconventional gas supplies.	Chapter 9, Natural Gas Analysis Appendix I, Natural Gas Analysis Results
WAC 480-90-238 (3) (d) An assessment of opportunities for using company-owned or contracted storage.	Chapter 9, Natural Gas Analysis Appendix I, Natural Gas Analysis Results
WAC 480-90-238 (3) (e) An assessment of pipeline transmission capability and reliability and opportunities for additional pipeline transmission resources.	Chapter 9, Natural Gas Analysis Appendix I, Natural Gas Analysis Results

Statutory or Regulatory Requirement	Chapter and/or Appendix
WAC 480-90-238 (3) (f) A comparative evaluation of the cost of natural gas purchasing strategies, storage options, delivery resources, and improvements in conservation using a consistent method to calculate cost-effectiveness.	Chapter 9, Natural Gas Analysis Appendix I, Natural Gas Analysis Results Appendix E, Conservation Potential Assessment and Demand Response Assessment
WAC 480-90-238 (3) (g) The integration of the demand forecasts and resource evaluations into a long-range (e.g., at least ten years; longer if appropriate to the life of the resources considered) integrated resource plan describing the mix of resources that is designated to meet current and future needs at the lowest reasonable cost to the utility and its ratepayers.	Chapter 3, Resource Plan Decisions
WAC 480-90-238 (3) (h) A short-term plan outlining the specific actions to be taken by the utility in implementing the long-range integrated resource plan during the two years following submission.	Chapter 1, Executive Summary
WAC 480-90-238 (3) (i) A report on the utility's progress towards implementing the recommendations contained in its previously filed plan.	Appendix B, Legal Requirements
WAC 480-90-238 (4) Timing. Unless otherwise ordered by the commission, each natural gas utility must submit a plan within two years after the date on which the previous plan was filed with the commission. Not later than twelve months prior to the due date of a plan, the utility must provide a work plan for informal commission review. The work plan must outline the content of the integrated resource plan to be developed by the utility and the method for assessing potential resources.	2021 Integrated Resource Plan Work Plan filed with the WUTC April, 2020, and Updated Work Plan filed May 15, 2020, July 8, 2020, September 17, 2020, October 26, 2020 and November 19, 2020.
WAC 480-90-238 (5) Public participation. Consultations with commission staff and public participation are essential to the development of an effective plan. The work plan must outline the timing and extent of public participation. In addition, the commission will hear comment on the plan at a public hearing scheduled after the utility submits its plan for commission review.	Appendix A, Public Participation

Figure B-5: Additional Condition Pursuant to WUTC Order 01 in Dockets UE-160918 and UG-160919

Statutory or Regulatory Requirement	Chapter and/or Appendix
Order 5-7 (5) For the 2019 IRP, PSE will hire a firm to do a survey of resource costs and recommend assumptions for use in the IRP. If reasonable, PSE will have the same consultants provide information for both fossil fuel plants and renewables. That study will include a detailed discussion of potential wind resources off the Washington coast, including areas that may be geographically limited for different reasons.	Appendix D, Electric Resources and Alternatives – For the 2019 IRP, PSE hired DNVGL to develop resource costs. For the 2021 IRP, PSE relied on public information and incorporated stakeholder feedback before finalizing the resource costs and assumptions.

Figure B-6: Natural Gas Utility Integrated Resource Plan HB 1257 Regulatory Requirements

Statutory or Regulatory Requirement	Chapter and/or Appendix
RCW 80.28.380 Each gas company must identify and acquire all conservation measures that are available and cost-effective. Each company must establish an acquisition target every two years and must demonstrate that the target will result in the acquisition of all resources identified as available and cost-effective. The cost-effectiveness analysis required by this section must include the costs of greenhouse gas emissions established in RCW 80.28.395. The targets must be based on a conservation potential assessment prepared by an independent third party and approved by the commission. Conservation targets must be approved by order by the commission. The initial conservation target must take effect by 2022.	Chapter 9, Natural Gas Analysis

Statutory or Regulatory Requirement	Chapter and/or Appendix
RCW 80.28.405 For the purposes of section 11 of this act, the cost of greenhouse gas emissions resulting from the use of natural gas, including the effect of emissions occurring in the gathering, transmission, and distribution of natural gas to the end user is equal to the cost per metric ton of carbon dioxide emissions, using the two and one-half percent discount rate, listed in table 2, Technical Support Document: Technical update of the social cost of carbon for regulatory impact analysis under Executive Order 12866, published by the interagency working group on social cost of greenhouse gases of the United States government, August 2016. The commission must adjust the costs established in this section to reflect the effect of inflation.	Chapter 5, Key Assumptions Chapter 9, Natural Gas Analysis

3. REPORT ON PREVIOUS ACTION PLANS

2017 Electric Action Plan

Per WAC 480-100-238 (3) (h), each item from the 2017 IRP electric resources action plan is listed below, along with the progress that has been made in implementing those recommendations.

Acquire Energy Efficiency

Develop two-year targets and implement programs that will put us on a path to achieve an additional 374 MW of energy efficiency by 2023 through program savings combined with savings from codes and standards.

> **PROGRESS:** PSE collaborated with the Conservation Resource Advisory Group (CRAG) to develop the 2018-2019 total electric conservation program savings target of 59.41aMW and the 2020-21 program cycle savings target of 60.05 aMW.

Demand Response

Clarify the acquisition, prudence criteria and cost recovery process for demand response programs. Issue a demand response RFP based on those findings. Re-examine the peak capacity value of demand response programs in the 2019 IRP to include day-ahead demand response programs, and use the sub-hourly flexibility modeling capability developed in this IRP to value sub-hourly demand response programs.

> **PROGRESS:** PSE is continuing to evaluate the best use cases for demand response (DR), including its potential as a non-wires alternative for transmission and distribution investments.
>
> PSE filed a Demand Response RFP on May 4, 2020. The RFP called for demand response program offers to help meet capacity needs of 250 MW by 2026. The DR RFP solicited bids for both a system-wide electric demand response program, as well as smaller (3 to 5 MW, 3 to 5k MBH), geographically targeted electric and natural gas DR programs. Shortly before the WUTC was to rule on PSE's Draft All-Source and DR RFPs in mid-July 2020, PSE's updated load forecast indicated a significant reduction by 2026. Absent the originally forecasted capacity need in 2026, PSE petitioned for and was granted permission to withdraw both draft RFPs. The UTC granted the request on October 15, 2020, with the understanding that PSE will re-submit updated All-Source and DR RFPs by April 1, 2021. More information about the RFPs, including the latest schedule updates, can be found online at www.pse.com/rfp.

Energy Storage

Install a small-scale flow battery to gain experience with the operation of this energy storage system in anticipation of greater reliance on flow batteries in the future.

PROGRESS: PSE installed a Primus EnergyPod flow battery at the Wild Horse Wind Facility's operations and maintenance building in April 2018. Technology and performance issues resulted in less than satisfactory operation, however, this test provided PSE with opportunities to learn about the challenges associated with flow battery technology. Ultimately, the flow battery was removed from the site after a year of trial and errors due to poor performance and leak issues. Once the battery was removed from the site, project documents were archived and communications with the vendor ceased.

Supply-side Resources: Issue an All-source RFP

Issue an all-source RFP in the first quarter of 2018 that includes updated resource needs and avoided cost information.

PROGRESS: PSE filed an All-resource RFP on June 8, 2018, which was subsequently approved by the WUTC on June 28, 2018. The RFP called for resources sufficient to meet PSE's need for additional capacity and renewable resources beginning in 2022 and 2023, respectively. To date, PSE has announced three resource acquisitions from the 2018 RFP: (1) a long-term power purchase agreement that will be supplied by Golden Hills, a 200 MW wind farm to be built by Avangrid Renewables in Sherman County, Ore.; (2) a five-year agreement with the Bonneville Power Administration for up to 100 MW of surplus power generated from the Federal Columbia River Power System; and (3) a long-term agreement to purchase the excess energy generated after wood waste is burned at Sierra Pacific Industries' cogeneration plant located at its Burlington lumber mill in Skagit County, Wash. More information about these resources can be found online at www.pse.com/rfp in the 2018 Demand Response and All-Source RFP Update section.

The RFP process is ongoing. PSE will update the website if and when new resources are contracted.

Develop Options to Mitigate Risk of Market Reliance

Develop strategies to mitigate the risk of redirecting transmission and increasing market reliance.

PROGRESS: In the 2017 IRP, PSE included a plan to redirect transmission from the Lower Snake River and Hopkins Ridge wind farms to Mid-C in the winter peak months. This would have provided for a low-cost alternative to increasing the amount of peak capacity associated with transmission at Mid-C. In the 2017-2018 winter months, PSE was unsuccessful in redirecting the amount of planned transmission from the wind farms to Mid-C due to constraints on BPA's affected flowgates. For this reason, this strategy was abandoned.

The idea of maintaining quick-build options has been abandoned. The "shelf life" of project permits is too short to justify the expense of obtaining them for a project that is merely an option. A more viable resource strategy is to rely upon shorter, three to five-year term deals from identified resources while longer term resources are selected and developed.

PSE continues to participate in wholesale energy markets in the western U.S., including the western states power pool, in order to make bilateral transactions to cover its energy and capacity needs. PSE has also joined markets for energy imbalance services and is involved in the extended day-ahead market initiative with others in the region.

Further analysis is provided in this IRP and documented in Chapters 5, 7 and 8.

Energy Imbalance Market (EIM)

Continue to participate in the California Energy Imbalance Market for the benefit of our customers.

PROGRESS: Participation has resulted in enhanced system reliability, more cost effective integration of variable energy resources, geographic diversity of electricity demand and generation resources, and cost savings for PSE customers. Benefits can take the form of cost savings or revenues or a combination of both. Benefits include transfer revenues, which are the net of payments received or paid by PSE for the transfer of energy between EIM participants; dispatch benefits, which are the difference between PSE's cost to dispatch resources to meet load on its own and PSE's cost to dispatch resources according to EIM instructions; greenhouse gas (GHG) revenues, which are payments from CAISO to offset California GHG cost obligations; and flexible ramping revenues, which are payments for transfer of flexible ramping capacity between EIM participants.

Regional Transmission

Examine regional transmission needs in the 2019 IRP in light of efforts to reduce the region's carbon footprint.

PROGRESS: Since 2019, PSE has taken steps to evaluate several regional transmission strategies that would help to address the future needs of CETA. These steps include:

- Analysis of PSE's existing portfolio of Bonneville Power Administration (BPA) transmission for opportunities to repurpose, redirect and/or share transmission with co-located resources.
- Expanded resource modeling in the 2021 IRP to consider regional transmission constraints.
- Participating in strategic discussions with BPA and other utilities in the Seattle area about expanding transmission across the Cascades.
- Evaluating investments in new regional transmission projects.
- Collaborating with NorthernGrid on the 2020-2021 regional study proposal.

Transmission updates are further discussed in Appendix J.

2017 Natural Gas Sales Action Plan

Acquire Energy Efficiency

Develop two-year targets and implement programs to acquire conservation, using the IRP as a starting point for goal-setting. This includes 14 MDth per day of capacity by 2022 through program savings and savings from codes and standards.

PROGRESS: PSE collaborated with the Conservation Resource Advisory Group (CRAG) to develop the 2018-2019 total gas conservation program savings target of 650 MDth and 2020-21 program cycle savings target of 795 MDth.

LNG Peaking Plant

Complete the PSE LNG peaking project located near Tacoma.

PROGRESS: Construction of the facility is nearing completion. PSE will begin plant commissioning and testing of the Tacoma LNG plant in January 2021, and normal operations will likely begin by March 2021.

Option to Upgrade Swarr

Maintain the ability upgrade the Swarr propane-air injection system in Renton, which the [2017 IRP] plan forecasts will be needed by the 2024/25 heating season.

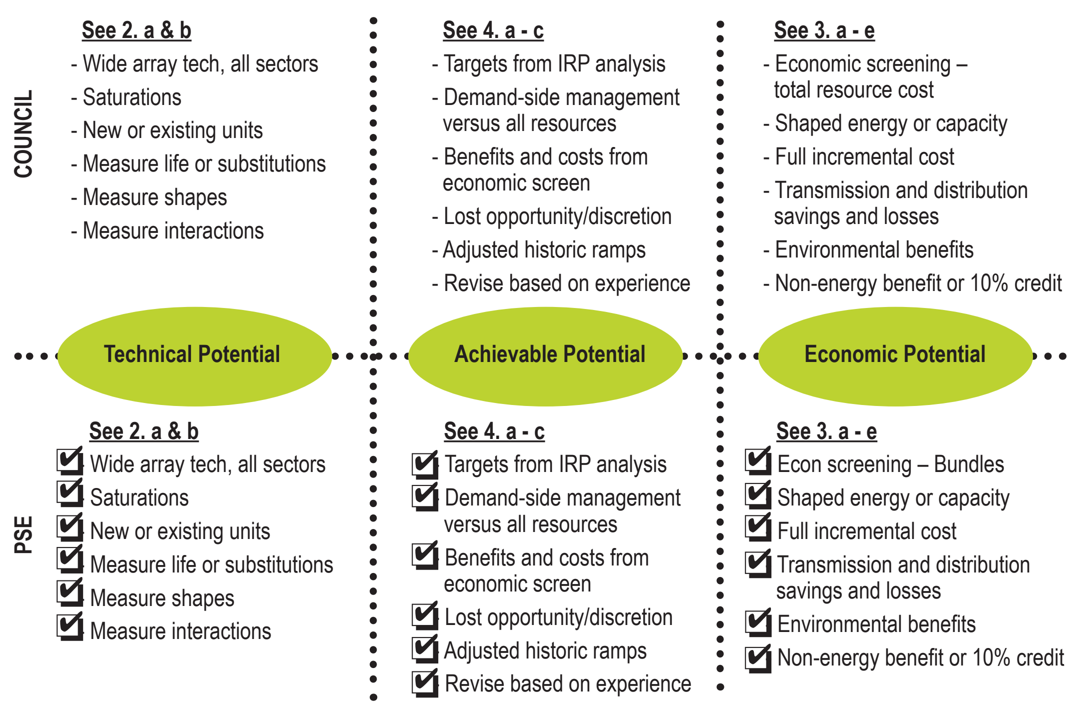
PROGRESS: The Swarr LP-Air facility is available for upgrade and the project can be upgraded on 2 years notice. Under the 2021 IRP Base Demand Forecast, the need for the upgrade is not currently forecasted to occur during the 2021 IRP study period.

4. OTHER REPORTS

Electric Demand-side Resource Assessment: Consistency with Northwest Power and Conservation Council Methodology

There are no legal requirements for the IRP to address the Northwest Power and Conservation Council (Council) methodology for assessing electric demand-side resources. Such comparison, however, may be useful for PSE and stakeholders in implementing sections of WAC 480-109. PSE has worked closely with Council staff on several aspects of our analytical process, including approaches to modeling demand-side resources. We are most grateful for the dialogue, and very much appreciate the opportunity to work with Council staff. WAC 480-109 does not define "methodology." PSE developed the detailed checklist below to demonstrate that our IRP process is consistent with the Council's methodology.[3]

Figure B-6: Comparison of Demand-side Resource Assessment Methodologies, PSE and the Northwest Power and Conservation Council



3 / *References in Figure B-4 refer to the Council's assessment of its methodology, found at: https://www.nwcouncil.org/media/112474/Methodology.pdf*

Department of Commerce
Integrated Resource Plan Cover Sheet

The WUTC is required to provide summary information about the IRPs of investor-owned utilities to the Department of Commerce. Information for the cover sheet is included in Figure B-7, below.

Figure B-7: Load-resource Balance Summary

Resource Plan Year:	2022
Base Year Start:	01/01/2022
Base Year End:	12/31/2022
Five-year Report Year:	2027
Ten-year Report Year:	2032

Report Years	*Base Year = 2022*			*2027*			*2032*		
Period	*Winter*	*Summer*	*Annual*	*Winter*	*Summer*	*Annual*	*Winter*	*Summer*	*Annual*
Units	*(MW)*	*(MW)*	*(aMW)*	*(MW)*	*(MW)*	*(aMW)*	*(MW)*	*(MW)*	*(aMW)*
Loads	4,687	3,515	2,500	4,949	3,848	2,647	5,269	4,220	2,820
Exports	24	324	59	0	300	47	0	300	47
Resources									
Conservation/Efficiency	72	33	32	383	188	213	693	335	417
Demand Response	0	0		89	89		198	198	
Cogeneration									
Hydro	743	774	514	762	808	505	757	801	504
Wind	118	118	295	113	113	485	129	129	475
Solar	12	12	38	12	12	38	11	11	38
Biomass	16	16	14	16	16	14	16	16	14
Thermal - Gas	2,050	1,689	1,856	1,689	2,050	1,856	2,050	1,689	1,856
Thermal - Coal	307	307	247			0			0
Long Term: BPA Base Year or Tier 1									
Net Long Term Contracts: Other	612	612	534	63	63	107	44	44	45
Net Short Term Contracts	1,518	1,487		1,479	1,433		1,479	1,435	
Other									
Imports	303	303	50	303	303	50	303	303	50
Total Resources	5,727	5,027	3,521	4,911	4,776	3,221	5,681	4,661	3,352
Load Resource Balance (Surplus) / Deficit	(1,039)	(1,512)	(1,020)	38	(928)	(574)	(412)	(442)	(532)

C Environmental Regulations

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

Contents

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 <u>not</u> 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.

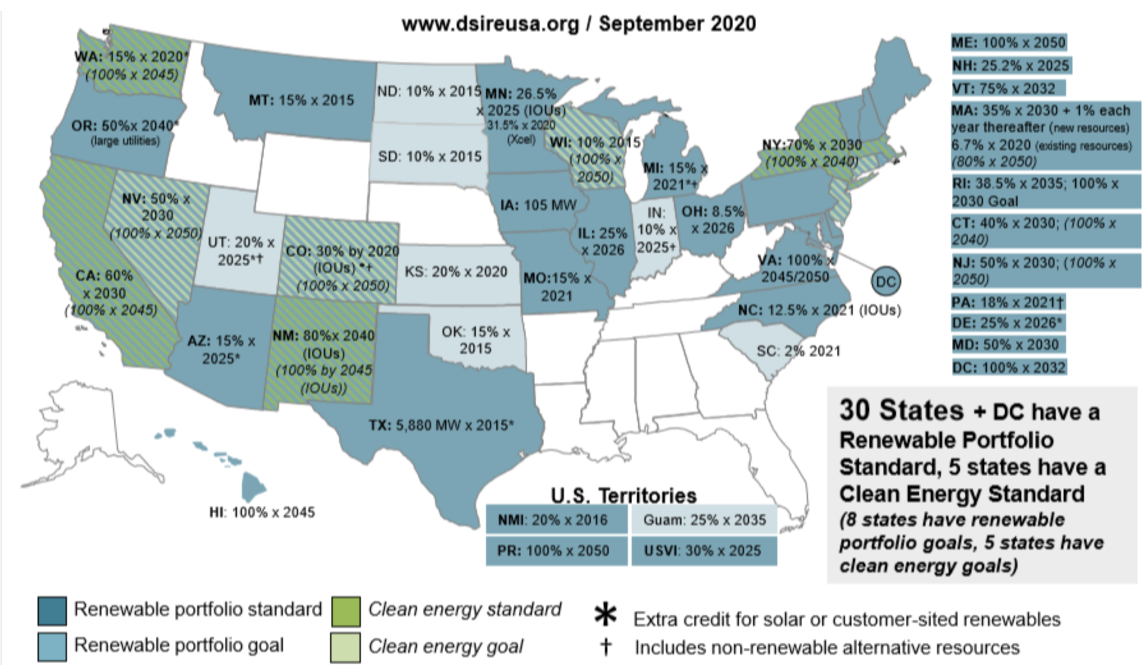
In September 2016, PSE, along with Avista Corporation, Cascade Natural Gas Corporation and NW Natural, filed a lawsuit in the U.S. District Court for the Eastern District of Washington challenging the CAR. In September 2016, the four companies filed a similar challenge to the CAR in Thurston County Superior 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.

2021 PSE Integrated Resource Plan

D

Electrical Resources and Alternatives

This appendix describes PSE's existing electric resources; current electric resource alternatives and the viability and availability of each; and estimated ranges for capital and operating costs. [1]

1 / *Operating costs are defined as operation and maintenance costs, insurance and property taxes. Capital costs are defined as depreciation and carrying costs on capital expenditures.*

Contents

1. RESOURCE TYPES

The following overview summarizes some of the distinctions used to classify electric resources.

Supply-side and Demand-side

Both of these types of resources are capable of enabling PSE to meet customer loads. Supply-side resources provide electricity to meet load, and these resources originate on the utility side of the meter. Demand-side resources contribute to meeting need by reducing demand. An "integrated" resource plan includes both supply- and demand-side resources.

SUPPLY-SIDE RESOURCES for PSE include:

- Generating plants, including combustion turbines (baseload and peakers), coal, hydro, solar and wind plants
- Long-term contracts with independent producers to supply electricity to PSE (these have a variety of fuel sources)
- Transmission contracts with Bonneville Power Administration (BPA) to carry electricity from short-term wholesale market purchases to PSE's service territory

DEMAND-SIDE RESOURCES for PSE include:

- Energy efficiency
- Distribution efficiency
- Generation efficiency
- Distributed generation
- Demand response

The contribution that demand-side programs make to meeting resource need is accounted for as a reduction in demand for the IRP analysis.

Thermal and Renewable

These supply-side resources are distinguished by the type of fuel they use.

THERMAL RESOURCES use fossil fuel (natural gas, oil, coal) or alternative fuels (biodiesel, hydrogen, renewable natural gas) to generate electricity. PSE's combustion turbines and coal-fired generating facilities are thermal resources.

RENEWABLE RESOURCES use renewable fuels such as water, wind, sunlight and biomass to generate electricity. Hydroelectricity and wind generation are PSE's primary renewable resources.

Baseload, Peaking, Intermittent and Storage

These distinctions refer to how the resource functions within the system.

BASELOAD RESOURCES produce energy at a constant rate over long periods at a lower cost relative to other production facilities available to the system. They are typically used to meet some or all of a region's continuous energy demand. Baseload resources usually have a high fixed cost but low marginal cost and thus could be characterized as the most efficient units of the fleet.

For PSE, baseload resources can be divided into two categories: thermal and hydro. These have different dispatching capabilities. Thermal baseload plants can take up to several hours to start and have limited ability to ramp up and down quickly, so they are not very flexible. Hydro plants, on the other hand, are very flexible and are typically the preferred resource to balance the system.

PSE's three sources of baseload energy are combined-cycle combustion turbines (CCCTs), hydroelectric generation and coal-fired generation.

PEAKING RESOURCES are quick-starting units that can ramp up and down quickly in order to meet short-term spikes in need. They also provide flexibility needed for load following, wind integration and spinning reserves. Peaking resources generally have a lower fixed cost but are less efficient than baseload plants. Historically, peaking units have low capacity factors because they are often not economical to operate compared to market purchases.

The flexibility of peaking resources will become more important in the future as new renewable resources are added to the system and as PSE continues to participate in the Energy Imbalance Market (EIM).

PSE's peaking resources include simple-cycle combustion turbines (SCCTs) and hydroelectric plants that can perform peaking functions in addition to baseload functions.

INTERMITTENT RESOURCES, also commonly referred to as Variable Energy Resources (VERs), provide power that offers limited discretion in the timing of delivery. Renewable resources like wind and solar are intermittent resources because their generating patterns vary as a result of uncontrollable environmental factors, so the timing of delivery from these resources doesn't necessarily align with customer demand. As a result, additional resources are required to back up intermittent resources in case the wind dies down or clouds cover the sun.

PSE's largest intermittent resources are utility-scale wind generation and solar generation. Other intermittent resources include small-scale power production from customer generation (including rooftop solar), and the 10 aMW of energy PSE is required to take from co-generation.

ENERGY STORAGE has the potential to provide multiple services to the system, including efficiency, reliability, capacity arbitrage, ancillary services and backup power for intermittent renewable generation. It is capable of benefiting all parts of the system – generation, transmission, distribution and end-use customers; however, these benefits vary by location and the specific application of the technology or resource. For instance, storage in one location could be installed to relieve transmission congestion and thereby defer the cost of transmission upgrades, while storage at another location might be used to back up intermittent wind generation and reduce integration costs.

PSE's energy storage resources include hydro reservoirs behind dams, oil backup for the peaking plants and batteries. Battery and pumped hydro energy storage operate with a limited duration and require generation from other sources. Detailed modeling is required to fully evaluate the value of energy storage at the sub-hourly level.

Capacity Values

The tables on the following pages describe PSE's existing electric resources using the net maximum capacity of each plant in megawatts (MW). Net maximum capacity is the capacity a unit can sustain over a specified period of time – in this case 60 minutes – when not restricted by ambient conditions or de-ratings, less the losses associated with auxiliary loads and before the losses incurred in transmitting energy over transmission and distribution lines. This is consistent with the way plant capacities are described in the annual 10K report[2] that PSE files with the U.S. Securities and Exchange Commission and the Form 1 report filed with the Federal Energy Regulatory Commission (FERC).

Different plant capacity values are referenced in other PSE publications because plant output varies depending upon a variety of factors, among them ambient temperature, fuel supply, whether a natural gas plant is using duct firing, whether a combined-cycle facility is delivering steam to a steam host, outages, upgrades and expansions. To describe the relative size of resources, it is necessary to select a single reference point based on a consistent set of assumptions. Depending on the nature and timing of the discussion, these assumptions – and therefore the expected capacity value – may vary.

2 / PSE's most recent 10K report was filed with the U.S. Securities and Exchange Commission in February 2020 for the year ending December 31, 2019. See http://www.pugetenergy.com/pages/filings.html.

2. EXISTING RESOURCES INVENTORY

Supply-side Thermal Resources

Baseload Combustion Turbines (CCCTs)

PSE’s six baseload combined-cycle combustion turbine plants have a combined net maximum capacity of 1,293 MW and supply 15 to 16 percent of PSE’s baseload energy needs, depending on market heat rates and plant availabilities. In a CCCT, the heat that a simple-cycle combustion turbine produces when it generates power is captured and used to create additional energy. This makes it a more efficient means of generating power than the peakers (simple-cycle turbines) described below. PSE's fleet of baseload CCCTs includes the following.

- **MINT FARM** is located in Cowlitz County, Wash.
- **FREDERICKSON 1** is located in Pierce County, Wash. (PSE owns 49.85 percent of this plant; the remainder of the plant is owned by Atlantic Power Corporation.)
- **GOLDENDALE** is located in Klickitat County, Wash.
- **ENCOGEN, FERNDALE** and **SUMAS** are located in Whatcom County, Wash.

Coal

The Colstrip generating plant currently supplies 16 to 17 percent of PSE’s baseload energy needs.

THE COLSTRIP GENERATING PLANT. Located in eastern Montana about 120 miles southeast of Billings, the plant consists of four coal-fired steam electric plant units. PSE owns 25 percent each of Units 3 & 4. PSE’s total ownership in Colstrip contributes 370 MW net maximum capacity to the existing portfolio.

The Colstrip Generating Plant Retirement/Shutdown Plan: After a request in June 2019 by PSE’s Unit 1 & 2 co-owner and plant operator, Talen Montana LLC, PSE agreed to retire the units. The decision was based on economic considerations. In early January 2020, the facility ceased to generate electricity and work commenced to place it in a secure and safe condition. Environmental remediation of impacted water is currently under way and will continue, in compliance with all local, state and federal regulations, as the retirement of the physical structures occurs. In the future, when Units 3 & 4 have also been retired, the main structures of Units 1 & 2 will be further addressed.

Units 3 & 4 are owned by six separate entities with different interests. PSE is limited in its ability to act unilaterally since operational decisions are dictated by the rules governing the ownership agreement. The Clean Energy Transformation Act (CETA) restricts PSE from serving load from Colstrip without penalty after 2025 and as a result this IRP only includes generation from Colstrip 3 & 4 through to 2025.

Figure D-1: PSE's Owned Baseload Thermal Resources

POWER TYPE	UNITS	PSE OWNERSHIP	NET MAXIMUM CAPACITY (MW)[1]
Coal	Colstrip 3 & 4[1]	25%	370
Total Coal			**370**
CCCT	Encogen	100%	165
CCCT	Ferndale[2]	100%	253
CCCT	Frederickson 1[2,3]	49.85%	136
CCCT	Goldendale[2]	100%	315
CCCT	Mint Farm[2]	100%	297
CCCT	Sumas	100%	127
Total CCCT			**1,293**

NOTES
1. Net maximum capacity reflects PSE's share only.
2. Maximum capacity of Ferndale, Frederickson 1, Goldendale and Mint Farm includes duct firing capacity.
3. Frederickson 1 CCCT unit is co-owned with Atlantic Power Corporation - USA.

Peakers (SCCTs)

These simple-cycle combustion turbines provide important peaking capability and help PSE meet operating reserve requirements. The company displaces these resources when their energy is not needed to serve load or when lower-cost energy is available for purchase. PSE's three peaker plants (eight units total) contribute a net maximum capacity of 612 MW. When pipeline capacity is not available to supply them with natural gas fuel, these units are capable of operating on distillate fuel oil.

- **FREDONIA** Units 1, 2, 3 and 4 are located near Mount Vernon, Wash., in Skagit County.
- **WHITEHORN** Units 2 and 3 are located in northwestern Whatcom County, Wash.
- **FREDERICKSON** Units 1 and 2 are located south of Seattle in east Pierce County, Wash.

Ownership and net maximum capacity are shown in Figure D-2 below.

Figure D-2: PSE's Owned Peaking Resources (Simple-cycle Combustion Turbines)

NAME	PSE OWNERSHIP	NET MAXIMUM CAPACITY (MW)
Fredonia 1 & 2	100%	207
Fredonia 3 & 4	100%	107
Whitehorn 2 & 3	100%	149
Frederickson 1 & 2	100%	149
Total SCCT		**612**

Supply-side Renewable Resources

Hydroelectricity

Hydroelectricity supplies approximately 14 percent of PSE's baseload energy needs. Even though restrictions to protect endangered species limit the operational flexibility of hydroelectric resources, these generating assets are valuable because of their ability to instantly follow customer load and because of their low cost relative to other power resources. High precipitation and snowpack levels generally allow more power to be generated, while low-water years produce less power. During low-water years, the utility must rely on other, more expensive, self-generated power or market resources to meet load. The analysis conducted for this IRP accounts for both seasonality and year-to-year variations in hydroelectric generation. PSE owns hydroelectric projects in western Washington and has long-term power purchase contracts with three public utility districts (PUDs) that own and operate large dams on the Columbia River in central Washington. In addition, we contract with smaller hydroelectric generators located within PSE's service territory.

BAKER RIVER HYDROELECTRIC PROJECT. This facility is located in Washington's north Cascade Mountains. It consists of two dams and is the largest of PSE's hydroelectric power facilities. The project contains modern fish-enhancement systems including a "floating surface collector" (FSC) to safely capture juvenile salmon in Baker Lake for downstream transport around both dams, and a second, newer FSC on Lake Shannon for moving young salmon around Lower Baker Dam. In addition to generating electricity, the project provides public access for recreation and significant flood-control storage for people and property in the Skagit Valley. Hydroelectric projects require a license from FERC for construction and operation. These licenses normally are for periods of 30 to 50 years; then they must be renewed to continue operations. In October 2008, after a lengthy renewal process, FERC issued a 50-year license allowing PSE to generate approximately 710,000 MWh per year (average annual output) from the Baker River project. PSE also completed construction of a new powerhouse and 30 MW generating unit at Lower Baker dam in July 2013. The replacement unit improves river flows for fish downstream of the dam while producing more than 100,000 additional MWh of energy from the facility each year. This incremental energy qualifies as a renewable resource under the State of Washington Energy Independence Act, RCW 19.285.

SNOQUALMIE FALLS HYDROELECTRIC PROJECT. Located east of Seattle on the Cascade Mountains' western slope, the Snoqualmie Falls Hydroelectric Project consists of a small diversion dam just upstream from Snoqualmie Falls and two powerhouses. The first powerhouse, which is encased in bedrock 270 feet beneath the surface, was the world's first completely underground power plant. Built in 1898-99, it was also the Northwest's first large hydroelectric power plant. FERC issued PSE a 40-year license for the Snoqualmie Falls Hydroelectric Project in 2004. The terms and conditions of the license allow PSE to generate an estimated 275,000 MWh per year (average annual output). The facility underwent a major redevelopment project between 2010 and 2015, which included substantial upgrades and enhancements to the power-generating infrastructure and public recreational facilities. Efficiency improvements completed as part of the redevelopment increase annual output by over 22,000 MWh. This incremental energy qualifies as a renewable resource under the State of Washington Energy Independence Act, RCW 19.285.

MID-COLUMBIA LONG-TERM PURCHASED POWER CONTRACTS. Under long-term power purchase agreements with three PUDs, PSE purchases a percentage of the output of five hydroelectric projects located on the Columbia River in central Washington. PSE pays the PUDs a proportionate share of the cost of operating these hydroelectric projects. In March 2017, PSE entered into a new power sales agreement with Douglas County PUD that began on August 31, 2018 and continues through September 30, 2028. Under this new agreement, PSE will continue to take a percentage of the output from the Wells project. The actual percentage available to PSE will be calculated annually and based primarily on Douglas PUD’s retail load requirements – as Douglas PUD’s retail load grows (or declines), they will reserve a greater (or lesser) share of Wells project output for their customers and the percentage PSE purchases will decline (or increase) as a result. PSE has a 20-year agreement with Chelan County PUD for the purchase of 25 percent of the output of the Rocky Reach and Rock Island projects that extends through October 2031. PSE has an agreement with Grant County PUD for a 0.64 percent share of the combined output of the Wanapum and Priest Rapids developments. The agreement with Grant County PUD will continue through the term of the project’s FERC license, which ends March 31, 2052.

Figure D-3: PSE Owned and Contracted Hydroelectric Resources

PLANT	OWNER	PSE SHARE %	NET MAXIMUM CAPACITY (MW)[1]	CONTRACT EXPIRATION DATE
Upper Baker River	PSE	100	91	None
Lower Baker River	PSE	100	105	None
Snoqualmie Falls	PSE	100	48[2]	None
Total PSE-owned			**244**	
Wells	Douglas Co. PUD	27.1	228[3]	9/30/28[3]
Rocky Reach	Chelan Co. PUD	25.0	325	10/31/31
Rock Island I & II	Chelan Co. PUD	25.0	156	10/31/31
Wanapum	Grant Co. PUD	0.6	7	03/31/52
Priest Rapids	Grant Co. PUD	0.6	6	03/31/52
Contracted Total			**706**	
Total Hydro			**950**	

NOTES
1. Net maximum capacity reflects PSE's share only.
2. The FERC license authorizes the full 54.4 MW; however, the project's water right, issued by the state Department of Ecology, limits flow to 2,500 cfs, and therefore output, to 47.7 MW.
3. In March 2017, PSE entered a new PPA with Douglas County PUD for Wells Project output that began on August 31, 2018 and continues through September 30, 2028. PSE also entered into an agreement in June 2018 to purchase an additional 5.5 percent of the Wells project through September 2021.

Wind Energy

PSE is the largest utility owner and operator of wind-power facilities in the Pacific Northwest. Combined, the maximum capacity of the company's three wind farms is 773 MW. They produce more than 2 million MWhs of power per year on average, which is about 8 percent of PSE's energy needs. These resources are integral to meeting renewable resource commitments.

HOPKINS RIDGE. Located in Columbia County, Wash., Hopkins Ridge has an approximate maximum capacity of 157 MW. It began commercial operation in November 2005.

WILD HORSE. Located in Kittitas County near Ellensburg, Wash., Wild Horse has an approximate maximum capacity of 273 MW. It came online in December 2006 at 229 MW and was expanded by 44 MW in 2010.

LOWER SNAKE RIVER. PSE brought online its third and largest wind farm in February 2012. The 343 MW facility is located in Garfield County, Wash.

Solar Energy

The Wild Horse facility contains 2,723 photovoltaic solar panels, including the first made-in-Washington solar panels.[3] The array can produce up to 0.5 MW of electricity with full sun. Panels can also produce power under cloudy skies – 50 to 70 percent of peak output with bright overcast and 5 to 10 percent with dark overcast. The site receives approximately 300 days of sunshine per year, roughly the same as Houston, Tex. On average this site generates 780 MWhs of power per year.

Battery Energy Storage System (BESS)

The Glacier Battery Demonstration Project was installed in early 2017. The 2 MW / 4.4 MWh lithium-ion battery storage system is located adjacent to the existing substation in Glacier, Wash., in Whatcom County. The Glacier battery serves as a short-term backup power source (up to 2.2 hours at capacity with a full charge) to a core "island" of businesses and residences during outages, reduces system load during periods of high demand, and helps balance energy supply and demand. The project was funded in part by a $3.8 million Smart Grid Grant from the State of Washington Department of Commerce. Between January and June, 2018, Pacific Northwest National Laboratory (PNNL) performed two use test cases. Since then, PSE has continued to test the battery's capabilities under planned outage scenarios – working toward the goal of successfully responding to unplanned outages.

Figure D-4 presents details about the company's wind, solar and battery storage resources.

3 / Outback Power Systems (now Silicon Energy) in Arlington produced the first solar panels in Washington. The Wild Horse Facility was Outback Power Systems' launch facility, utilizing 315 of their panels. The remaining panels were produced by Sharp Electronics in Tennessee.

Figure D-4: PSE's Owned Wind, Solar and Battery Storage Resources

POWER TYPE	UNITS	PSE OWNERSHIP	NET MAXIMUM CAPACITY (MW)
Wind	Hopkins Ridge	100%	157
Wind	Lower Snake River, Phase 1	100%	343
Wind	Wild Horse	100%	273
Total Wind			**773**
Solar	Wild Horse Solar Demonstration Project	100%	0.5
Energy Storage	Glacier Battery Demonstration Project	100%	2.0
Total Solar and Storage			**2.5**
Total Wind, Solar and Battery Storage			**775.5**

Supply-side Contract Resources

Long-term contracts consist of agreements with independent producers and other utilities to supply electricity to PSE. Fuel sources include hydropower, wind, solar, natural gas, coal, waste products and system deliveries without a designated supply resource. These contracts are summarized in Figure D-5. Short-term wholesale market purchases negotiated by PSE's energy trading group are not included in this listing.

POINT ROBERTS PPA. This contract provides for power deliveries to PSE's retail customers in Point Roberts, Wash. The Point Roberts load, which is physically isolated from PSE's transmission system, connects to British Columbia Hydro's electric distribution facilities. PSE pays a fixed price for the energy during the term of the contract.

BAKER REPLACEMENT. Under a 20-year agreement signed with the U.S. Army Corps of Engineers (USACE) PSE provides flood control for the Skagit River Valley. Early in the flood control period, PSE drafts water from the Upper Baker reservoir at the request of the USACE. Then, during periods of high precipitation and runoff between October 15 and March 1, PSE stores water in the Upper Baker reservoir and releases it in a controlled manner to reduce downstream flooding. In return, PSE receives a total of 7,000 MWhs of power and 7 MW of net maximum capacity from BPA in equal increments per month for the months of November through February to compensate for the lower generating capability caused by reduced head due to the early drafting at the plant during the flood control months.

PACIFIC GAS & ELECTRIC COMPANY (PG&E) SEASONAL EXCHANGE. Under this system-delivery power exchange contract, each calendar year PSE exchanges with PG&E 300 MW of seasonal capacity, together with 413,000 MWh of energy, on a one-for-one basis. PSE is a winter-peaking utility and PG&E is a summer-peaking utility, so PG&E has the right to call for the power in the months of June through September, and PSE has the right to call for the power in the months of November through February.

CANADIAN ENTITLEMENT RETURN. Under a treaty between the United States and Canada, one-half of the firm power benefits produced by additional storage capability on the Columbia River in Canada accrue to Canada. PSE’s benefits and obligations from this storage are based on the percentage of our participation in the Columbia River projects. Agreements with the Mid-Columbia PUDs specify PSE’s share of the obligation is to return one-half of the firm power benefits to Canada during peak hours until the expiration of the PUD contracts or expiration of the Columbia River Treaty, whichever occurs first. This is energy that PSE provides rather than receives, so it is a negative number. The energy returned during 2018 was approximately 18 aMW with a peak capacity return of 32.5 MW. The Columbia River Treaty has no end date but can be terminated after 2024 with 10 years’ notice. The United States and Canada recently concluded the ninth round of negotiations to modernize the treaty to ensure the effective management of flood risk, provide a reliable and economical power supply, and improve the ecosystem.

COAL TRANSITION PPA. Under the terms of this agreement, PSE began to purchase 180 MW of firm, baseload coal transition power from TransAlta’s Centralia coal plant in December 2014. On December 1, 2015, the contract increased to 280 MW. From December 2016 to December 2024 the contract is for 380 MW, and in the last year of the contract, 2025, volume drops to 300 MW. This contract conforms to a separate TransAlta agreement with state government and the environmental community to phase out coal-fired power generation in Washington by 2025. In 2011, the state Legislature passed a bill codifying a collaborative agreement between TransAlta, lawmakers, environmental advocacy groups and labor representatives. The timelines agreed to by the parties enable the state to make the transition to cleaner fuels, while preserving the family-wage jobs and economic benefits associated with the low-cost, reliable power provided by the Centralia plant. The legislation allows long-term contracts, through 2025, for sales of coal transition power associated with the 1,340 MW Centralia facility, Washington’s only coal-fired plant.

KLONDIKE III PPA. PSE's wind portfolio includes a power purchase agreement with Avangrid Renewables[4] for a 50 MW share of electricity generated at the Klondike III wind farm in Sherman County, Ore. The wind farm has 125 turbines with a project capacity of nearly 224 MW. This agreement remains in effect until November 2027.

4 / Formerly Iberdrola

LUND HILL SOLAR PPA. PSE has executed a 20-year power purchase agreement with Avangrid Renewables (through the project company Lund Hill Solar, LLC) to purchase the output from the Lund Hill Solar Project, to be located in Klickitat County, Wash. The project has an expected online date in March 2021. The output from the facility will be used to serve subscribers to PSE's new Green Direct program (Schedule 139), which is described in the Demand-side Resources section of this appendix.

SKOOKUMCHUCK WIND PPA. PSE has executed a 20-year power purchase agreement with Renewable Energy Systems (RES) to purchase the output from the Skookumchuck Wind Project.[5] The wind project is currently in development in Thurston and Lewis counties and is scheduled to be operational by the end of 2020.[6] Along with the output from Lund Hill Solar facility, the Skookumchuck facility output will be used to serve subscribers to PSE's Green Direct program (Schedule 139), which is described in the Demand-side Resources section of this appendix.

ENERGY KEEPERS PPA. PSE has entered into an agreement with Energy Keepers, Inc., the tribally owned corporation of the Confederated Salish and Kootenai Tribes, to purchase 40 MW of zero carbon energy produced by the Selis Ksanka Qlispe hydroelectric project through July of 2035.

SPI BIOMASS PPA. PSE has entered into a 17-year contract with Sierra Pacific Industries (SPI) to purchase 17 MW of renewable energy from SPI's Mt. Vernon Mill starting in 2021. SPI's cogeneration facility is an operational plant that uses wood byproducts from its lumber manufacturing process to generate steam used to make electricity and heat kilns to dry lumber. An air pollution control device filters out fine particles and other emissions from the burning wood so that what is released into the atmosphere comes out clean.

BPA CAPACITY PRODUCT. Under a five-year agreement beginning in January 2022, the Bonneville Power Administration will offer to sell PSE up to 100 MW of surplus power generated from the Federal Columbia River Power System. Hydroelectricity can quickly increase and decrease to meet power demand, and help the region achieve its renewable goals by dovetailing with more variable output resources such as wind and solar.

5 / PSE was notified on 10/24/2019 that Southern Power Company had purchased the project.
6 / The estimated in service COD is November 2, 2020.

MSCG SYSTEM PPA. PSE has entered into a Western System Power Pool (WSPP) agreement with the Morgan Stanley Commodities Group (MSCG) for a 4-year, 363-day, system PPA to deliver 100 MW of firm heavy load hour (HLH) energy in Q1 and Q4 only, commencing in January 2022.

GOLDEN HILLS WIND PPA. PSE has executed a 20-year power purchase agreement with Avangrid Renewables for the output of a 200 MW wind farm to be built in Sherman County, Ore. Avangrid expects to complete the project by late 2021. The project will help PSE meet its goals to reduce carbon dioxide emissions while providing additional capacity to serve customers, particularly during winter periods of high electricity demand.

RFP RESOURCE PPA. PSE expects to complete execution of a 20-year power purchase agreement in early 2021. For the purposes of this IRP, which files in April, it is labeled as a generic RFP resource.

HYDROELECTRIC PPAs. Among PSE's power purchase agreements are several long-term contracts for the output of production from hydroelectric projects within its balancing area. These contracts are shown in Figure D-5 below and have the designator "Hydro – QF" for qualifying facility. The projects are run-of-river and do not provide any flexible capacity.

SCHEDULE 91 CONTRACTS. PSE's portfolio includes a number of electric power contracts with small power producers in PSE's electric service area (see Figure D-5). These qualifying facilities offer output pursuant to WAC chapter 480-106. WAC 480-106-020 states: "A utility must purchase, in accordance with WAC 480-106-050 Rates for purchases from qualifying facilities, any energy and capacity that is made available from a qualifying facility: (a) Directly to the utility; or (b) Indirectly to the utility in accordance with subsection (4) of this section." A qualifying facility is defined in WAC 480-106-007 as a "cogeneration facility or small power production facility that is a qualifying facility under 18 C.F.R. Part 292 Subpart B."

Figure D-5: Long-term Contracts for Electric Power Generation (continued next page)

NAME	POWER TYPE	CONTRACT START	CONTRACT EXPIRATION	CONTRACT CAPACITY (MW)
Pt. Roberts[1]	System	10/1/2019	9/30/2022	8
Baker Replacement	Hydro	10/1/2019	9/30/2029	7
PG&E Seasonal Exchange-PSE	System	10/11/1991	Ongoing	300
Canadian Entitlement Return	Hydro	1/1/2004	09/15/2024	(32.5)
Coal Transition PPA	Transition Coal	12/1/2014	12/31/2025	380 [2]
Klondike III PPA	Wind	12/1/2007	11/30/2027	50
Energy Keepers PPA	Hydro	3/1/2020	7/31/2035	40
SPI Biomass PPA	Biomass	1/1/2021	12/31/2037	17
BPA Capacity Product PPA	Hydro	1/1/2022	12/31/2026	100
MSCG System PPA	System	1/3/2022	12/31/2026	100
Golden Hills Wind PPA	Wind	7/1/2022	6/30/2042 [3]	200
RFP Resource	Wind	TBD	TBD	350
Lund Hill Solar	Schedule 139 – Solar	3/1/2021	7/01/2041[4]	150
Skookumchuck Wind	Schedule 139 - Wind	6/30/2020	12/31/2039 [5]	136.8
Twin Falls PPA	Hydro-QF	12/1/1989	3/018/2025	20
Koma Kulshan PPA	Hydro-QF	12/1/1990	3/31/2037	13.3
Weeks Falls PPA	Hydro-QF	12/1/1987	12/01/2022	4.6
Farm Power Rexville	Schedule 91 - Biogas	8/28/2009	12/31/2023	0.75
Farm Power Lynden	Schedule 91 - Biogas	12/1/2010	12/31/2023	0.75
Rainier Biogas	Schedule 91 – Biogas	11/30/2012	12/31/2023	1.0
Vanderhaak Dairy	Schedule 91 – Biogas	11/5/2004	12/31/2023	0.60 [6]
Edaleen Dairy	Schedule 91 – Biogas	8/21/2012	12/31/2023	0.75
Van Dyk - Holsteins Dairy	Schedule 91 – Biogas	6/1/2011	12/31/2023	0.47
Blocks Evergreen Dairy	Schedule 91 – Biogas	6/1/2017	12/31/2031	0.19
Emerald City Renewables [7]	Schedule 91 – Biogas	11/6/2013	12/31/2029	4.50
Emerald City Renewables 2	Schedule 91 – Biogas	12/31/2018	12/31/2031	4.50
Skookumchuck Hydro	Schedule 91 – Hydro	2/25/2011	1/31/2024	1.0
Black Creek	Schedule 91 – Hydro	3/26/2021	3/25/2031	4.2
Nooksack Hydro	Schedule 91 – Hydro	1/1/2014	12/31/2023	3.5
Sygitowicz – Kingdom Energy [8]	Schedule 91 – Hydro	3/25/2016	12/31/2030	0.448

NAME	POWER TYPE	CONTRACT START	CONTRACT EXPIRATION	CONTRACT CAPACITY (MW)
Island Solar [9]	Schedule 91 – Solar	6/22/2011	12/31/2023	0.075
Finn Hill Solar (Lake Wash SD)	Schedule 91 – Solar	7/16/2012	12/31/2023	0.355
CC Solar #1, LLC and CC Solar #2, LLC (combined)	Schedule 91 – Solar	9/28/2012	1/1/2026	0.026
IKEA	Schedule 91 – Solar	1/1/2017	12/31/2031	0.828
TE – Fumeria	Schedule 91 – Solar	1/1/2020	12/31/2031	4.99
TE – Penstemon	Schedule 91 – Solar	1/1/2020	12/31/2031	4.99
TE – Typha	Schedule 91 – Solar	1/1/2020	12/31/2031	4.99
TE – Urtica	Schedule 91 – Solar	8/1/2018	12/31/2031	4.99
TE – Camas	Schedule 91 – Solar	8/1/2018	12/31/2031	4.99
Iron Horse Solar	Schedule 91 – Solar	6/1/2018	12/31/2030	4.5
Osprey	Schedule 91 – Solar	6/1/2018	12/31/2030	0.95
Heelstone Energy – Westside Solar	Schedule 91 – Solar	10/1/2019	12/31/2031	4.99
Heelstone Energy – Dry Creek Solar	Schedule 91 – Solar	10/1/2019	12/31/2031	4.99
Cypress Renewables – Gholson Solar	Schedule 91 – Solar	1/1/2020	12/31/2032	4.99
GCSD PSE3 LLC	Schedule 91 – Solar	7/1/2018	12/31/2031	4.0
Knudson Wind	Schedule 91 – Wind	6/16/2011	12/31/2023	0.108
3 Bar-G Wind	Schedule 91 – Wind	8/31/2011	12/31/2023	0.120 [10]
Swauk Wind	Schedule 91 – Wind	12/14/2012	12/31/2023	4.25
Total				**1,923**

NOTES
1. The contract to provide power to PSE's Point Roberts customers expired on 9/30/2019 and the new contract with a three-year term was negotiated between PSE and PowerEx, commencing October 1, 2019. Point Roberts is not physically interconnected to PSE's system, and relies on power from a single intertie point on BC Hydro's distribution grid.
2. The capacity of the TransAlta Centralia PPA is designed to ramp up over time to help meet PSE's resource needs. According to the contract, PSE will receive 280 MW from 12/1/2015 to 11/30/2016, 380 MW from 12/1/2016 to 12/31/2024 and 300 MW from 1/1/2025 to 12/31/2025.
3. A 1-year system PPA for interim capacity has also been signed in the event that COD is pushed past December 2021, but no later than June 20, 2022.
4. 20-year term subject to final COD date, now anticipated in Q1, 2021.
5. 20-year term subject to final COD date.
6. VanderHaak has two generators with a combined capacity of .60 MW. However, VanderHaak primarily runs only the larger generator, which has a capacity of .45 MW.
7. Emerald City Renewables was formerly known as BioFuels Washington.

8. The site was purchased on May 1, 2020 by Hillside Clean Energy with PSE's consent.
9. Ownership was transferred to the Port of Coupeville on July 1, 2020 with PSE's consent.
10. Agreement originally for 1.395 MW but only 0.120 MW was constructed and the contract was amended to reflect this change.

Supply-side Transmission Resources

Mid-C Transmission Resources

Transmission capacity to the Mid-Columbia (Mid-C) market hub gives PSE access to the principal electricity market hub in the Northwest, which is one of the major trading hubs in the Western Electricity Coordinating Council (WECC). It is the central market for northwest hydroelectric generation. PSE has 2,481 MW of transmission capacity to the Mid-C market; of that, 2,031 MW is contracted from BPA on a long-term basis and 450 MW is owned by PSE.[7] The BPA transmission rights are owned by PSE Merchant. The 450 MW of transmission is sold by PSE Transmission as the Transmission Provider. Currently, PSE's 449 customers hold the rights to the 450 MW of transmission; however, when these rights are not fully utilized by the 449 customers, these transmission rights are allocated to PSE Merchant or sold on OASIS. PSE's Mid-C transmission capacity is detailed in Figure D-6 below; approximately 1,500 MW of this transmission capacity to the Mid-C wholesale market is utilized for short-term market purchases to meet PSE's peak need.[8]

7 / PSE also owns transmission and transmission contracts to other markets in addition to the Mid-C market transmission detailed here.
8 / See Chapter 8, Electric Analysis, for a more detailed discussion of PSE reliance on wholesale market capacity to meet peak need.

Figure D-6: Mid-C Hub Transmission Resources

NAME	EFFECTIVE DATE	TERMINATION DATE	TRANSMISSION DEMAND (MW)
BPA Mid-C Transmission			
Midway	11/1/2017	11/1/2022	100
Midway	4/1/2008	11/1/2035	5
Rock Island	7/1/2007	7/1/2037	400
Rocky Reach[9]	11/1/2017	11/1/2022	100
Rocky Reach	11/1/2017	11/1/2022	100
Rocky Reach	11/1/2019	11/1/2024	40
Rocky Reach	11/1/2019	11/1/2024	40
Rocky Reach	11/1/2019	11/1/2024	40
Rocky Reach	11/1/2019	11/1/2024	5
Rocky Reach	11/1/2019	11/1/2024	55
Rocky Reach	9/1/2014	11/1/2031	160
Vantage	11/1/2017	11/1/2022	100
Vantage	12/1/2019	12/1/2024	169
Vantage	10/1/2013	3/1/2025	3
Vantage	11/1/2019	11/1/2024	27
Vantage	11/1/2019	11/1/2024	27
Vantage	11/1/2019	11/1/2024	27
Vantage	11/1/2019	11/1/2024	3
Vantage	11/1/2019	11/1/2024	36
Vantage	11/1/2019	11/1/2024	5
Wells	9/1/2018	9/1/2023	266
Vantage	3/1/2016	2/28/2021	23
Midway	10/1/2018	10/1/2023	115
Midway	3/1/2019	3/1/2024	35
Wells/Sickler	11/1/2018	11/1/2023	50
Vantage	11/1/2018	11/1/2023	50
Vantage	12/1/2019	11/1/2022	50
Total BPA Mid-C Transmission			**2,031**
PSE Owned Mid-C Transmission			
McKenzie to Beverly	-	-	50
Rocky Reach to White River	-	-	400
Total PSE Mid-C Transmission			**450**
Total Mid-C Transmission			**2,335**

9 / *Contract split between Mid-C and EIM Imports below*

EIM Transmission Resources

When PSE joined the Energy Imbalance Market (EIM) in October 2016, it redirected 300 MW of Mid-C transmission capacity contracted from BPA on an annual basis for EIM trades. Starting in June 2020, Mid-C transmission redirected for use in the EIM was reduced to 150 MW in order to align with PSE's market-based rate authority. This is a required amount to maintain market-based authority and still gives PSE the capability to redirect beyond this amount for use in the EIM. Although these redirects reduce transmission capacity available to support PSE's peak need, PSE still maintains sufficient capacity to meet the winter peak. The amount of redirected Mid-C transmission will need to be renewed on an ongoing basis, and this will allow PSE to reevaluate its EIM transfer capacity needs in light of future winter peak needs. Figure D-7 details the transmission capacity currently redirected for EIM.

An additional 300 MW reserved under the PG&E Seasonal Exchange contract is redirected for EIM during certain months of the year on an as-feasible basis. When PSE's obligations to PG&E during summer months prevent this redirect, PSE instead redirects its existing Mid-C transmission, bringing total redirected Mid-C transmission for EIM during summer months up to 450 MW.

Figure D-7: Mid-C Hub Transmission Resources Redirected for EIM as of 1/1/2021

NAME	EFFECTIVE DATE	TERMINATION DATE	TRANSMISSION DEMAND (MW)
BPA Mid-C Transmission Redirected for EIM			
Rocky Reach	11/1/2017	11/1/2022	150
Total BPA Mid-C Transmission Redirected for EIM			**150**

Demand-side Resources

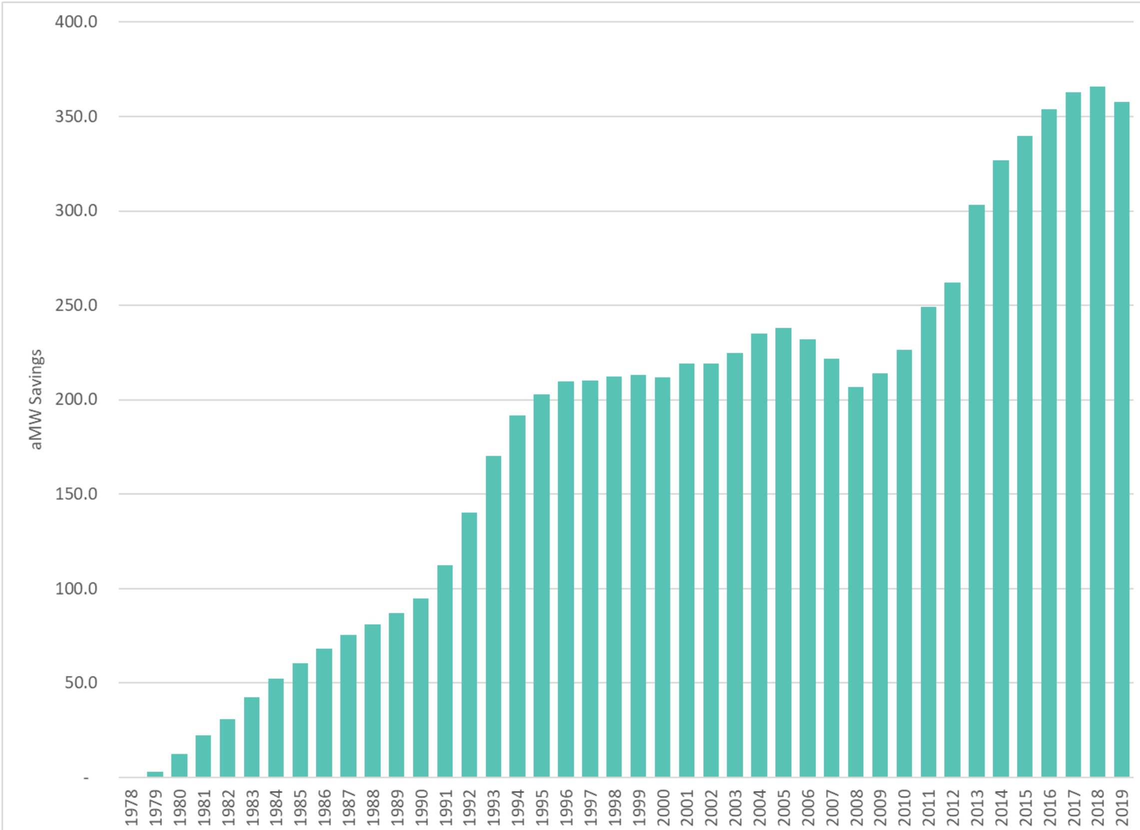
Energy reduction and energy production programs that contribute to meeting need by reducing demand are called demand-side resources (DSR). These are often implemented on the customer side of the meter. DSR programs currently offered through PSE include:

- **ENERGY EFFICIENCY**, implemented by PSE's Customer Energy Management group
- **DISTRIBUTION EFFICIENCY**, managed by PSE's System Planning group
- **GENERATION EFFICIENCY**, evaluated by PSE's Customer Energy Management group (This represents energy efficiency opportunities at PSE generating facilities.)
- **DISTRIBUTED GENERATION**, overseen by PSE's Customer Energy Management group (with the exception of distributed solar photovoltaics, which is overseen by the Customer Renewable Energy Programs group)
- **DEMAND RESPONSE** pilots, currently overseen by PSE's Customer Energy Management group

PSE has been a leader in the Pacific Northwest when it comes to implementation of demand-side energy efficiency resource programs. Since 1978, annual first-year savings (as reported at the customer meter) have grown by more than 300 percent, from 9 aMW in 1978 to 27.6 aMW in 2019. On a cumulative basis, these savings reached a total of 358 aMW by 2019. (Savings are adjusted for measure life and then retired so they no longer count towards the cumulative savings.[10]) To achieve these savings over the 1978 to 2019 period, the company spent a total of approximately $1.57 billion in incentives to customers and for program administration.

10 / For the purposes of the IRP analysis, measure life is assumed to be 10 years.

Figure D-8: Cumulative Electric Energy Efficiency Savings from DSR, 1978 through 2019



Energy Efficiency

Energy efficiency is by far PSE's largest electric demand-side resource. It consists of measures and programs that replace existing building components and systems such as lighting, heating, water heating, insulation, appliances, etc. with more energy efficient ones. There are two types of measures: "retrofit measures" (when replacement is cost effective before the equipment reaches its end of life); and lost opportunity measures (when replacement is not cost effective until existing equipment burnout).

PSE energy efficiency programs serve all types of customers – residential (including low income), commercial and industrial. Program savings targets are established every two years in collaboration with key external stakeholders represented by the Conservation Resource Advisory Group (CRAG) and the IRP public participation process. The majority of electric energy efficiency programs are funded using electric "conservation rider" funds collected from all customer classes.[11]

11 / See Electric Schedule 120, Electricity Conservation Service Rider, for more information.

In the most recently completed program cycle, the 2018-19 tariff period, energy efficiency achieved a total savings of 61.4 aMW; the target for the current 2020-21 program cycle is 60.0 aMW. Some of the changes in the 2020-21 program cycle are noted below.[12]

- HB1444 made high efficiency LED lighting the baseline technology, so the general service LED lighting savings, which a huge part of the residential program savings will no longer be offered and will be replaced with other program offerings. The home energy assessment program which relied on LED savings will be repurposed to focus on hard to reach customers only.
- Expanded distribution channels for high efficiency space heating and water heating heat pump products for residential customers.
- Expanded home energy reports program to enroll more customers.
- Target moderate income residences that are not qualified under the low income category for space, water and weatherization measures.
- Increased incentives for lighting and non-lighting measures in the commercial and industrial sectors.
- Expanded distribution channels for delivery of heat pumps in commercial and industrial sectors.

The 2020-2021 electric energy efficiency programs are targeted to save 60.05 aMW of electricity at a cost of just under $194 million.

12 / See 2020-21 Biennium Conservation Plan Overview for more details on efficiency programs, especially low-income weatherization programs.

Distribution Efficiency

The Production and Distribution Efficiency program includes implementing energy conservation measures within PSE's own distribution facilities that prove cost-effective, reliable and feasible.

For transmission and distribution (T&D) efficiency, improvements are implemented at PSE's electric substations. These improvements focus on measures like phase balancing and conservation voltage reduction (CVR). The methodology used to determine CVR savings is the Simplified Voltage Optimization Measurement and Verification Protocol provided by the Northwest Power and Conservation Council Regional Technical Forum.[13]

Figure D-9 below lists the CVR-related projects completed to date and planned for the 2020-21 period. In future years, a significant expansion in CVR project implementation is planned, tied to the implementation of the Advanced Metering Infrastructure (AMI) project and substation automation project. These two projects will enable Volt-Var optimization (VVO), an improved CVR method that allows for deeper levels of savings compared to PSE's current CVR implementation method of line drop compensation (LDC).

Savings associated with CVR are affected by several variables, including but not limited to the increasing penetration of distributed energy resources (DERs) that is expected in the future. Therefore, the savings from these projects can vary significantly. PSE is currently investigating the need for a study that provides an updated energy savings methodology for Volt-Var CVR projects. Currently, the first Volt-Var CVR project is expected to launch in 2023.

13 / *rtf.nwcouncil.org*

Figure D-9: Energy Savings from Conservation Voltage Reduction, Cumulative Savings to Date, kWh

Substation	Year of Execution	Date of Completion	Date of QC of Non-payment Request	kWh Savings / YEAR	Savings as % of Baseline kWh
South Mercer	2013	11/1/2013	12/18/2013	607,569	1.3%
Mercerwood	2013	12/8/2013	12/18/2013	357,240	0.9%
Mercer Island	2014	8/8/2014	9/22/2014	859,586	1.3%
Britton	2014	12/5/2014	12/24/2014	636,197	5.6%
Panther Lake	2015/2016	8/27/2015	6/23/2016	804,326	1.3%
Hazelwood	2015/2016	9/18/2015	6/23/2016	1,352,149	1.4%
Pine Lakes	2015/2016	9/17/2015	6/23/2016	1,163,150	1.3%
Fairwood	2017/2018	5/1/2018	11/13/2018	768,367	1.2%
Rhode Lakes	2017/2018	5/23/2018	11/13/2018	1,639,803	1.6%
Rolling Hills	2017/2018	5/24/2018	11/2/2018	1,359,515	1.5%
Phantom Lake	2018/2019	12/19/2018	4/16/2019	343,748	0.8%
Overlake	2018/2019	12/6/2019	12/27/2019	326,644	1.0%
Lake McDonald	2020	5/26/2020		404,699	1.0%
Maplewood	2020	In progress		1,534,573	estimate
Cambridge	2021	In progress		956,084	estimate
Marine View	2021	In progress		1,600,000	estimate
Klahanie	2021	In progress		1,072,000	estimate
Norway Hills	2021	In progress		1,356,225	estimate
Average to Date				**952,326**	**1.6%**
Total to Date		**11/19/2020**		**10,218,294**	

Generation Efficiency

In 2014, PSE worked with the CRAG to refine the boundaries of what to include as savings under generation efficiency. It was determined that only parasitic loads[14] served directly by a generator would be included in the savings calculations as available for generation efficiency upgrades; generators whose parasitic loads are served externally – from the grid – would not be included. Using this definition, PSE completed site assessments in 2015 and the assessments did not yield any cost-effective measures. Most of the opportunities were in lighting, and very low operating hours made these opportunities not cost effective.

14 / Electric generation units need power to operate the unit, including auxiliary pumps, fans, electric motors and pollution control equipment. Some generating plants may receive this power externally, from the grid; however, many use a portion of the gross electric energy generated by the unit for operations – this is referred to as the "parasitic load."

Analyses performed during 2020-2021 planning revealed that there are no cost-effective measures available for PSE generation facilities. Program staff will continue examination of these facilities in 2020 and adjust PSE's 2021 Annual Conservation Plan, should conservation opportunities in generating facilities become cost effective.[15]

Distributed Generation

PSE offers cogeneration/combined heat and power incentives under its commercial and industrial programs. However, to date no project has been implemented.

Renewable distributed generation programs are discussed under "Customer Renewable Energy Programs" in the next section.

Demand Response

PSE will file an All-Source RFP and a Demand Response RFP with the WUTC in 2021.

In the meantime, PSE's Customer Energy Management group plans to operate geographically targeted pilots in both a natural gas (Duvall) and an electric (Bainbridge Island) program in 2021.

15 / *2021 Annual Conservation Plan*

Demand-side Customer Programs

Customer Renewable Energy Programs

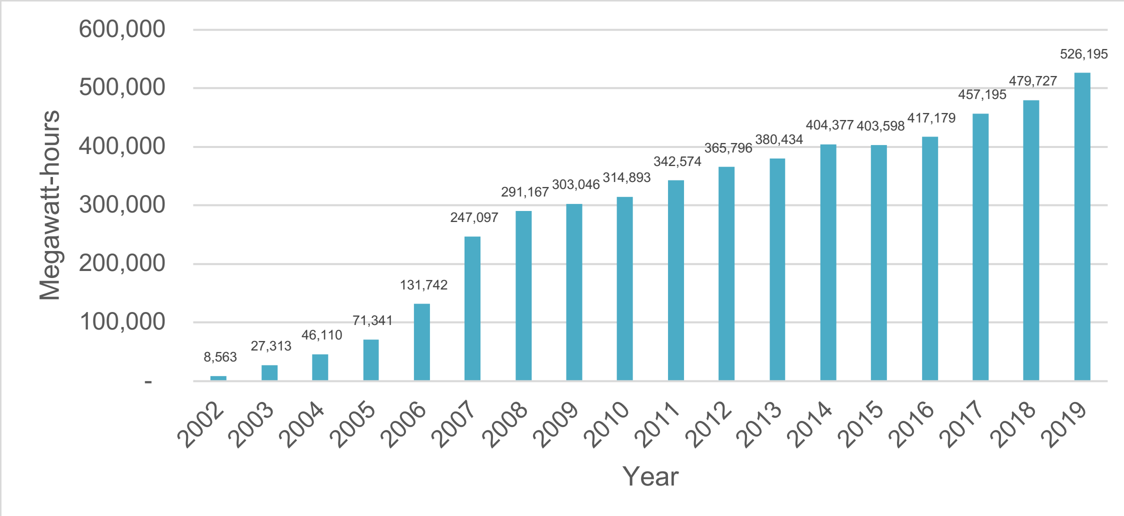
PSE's customer renewable energy programs remain popular options. The Green Power Program serves customers who want to purchase additional renewable energy, and Net Metering and Local Energy Development programs serve customers who generate renewable energy on a small scale. Our customers find value as well as social benefits in these programs, and PSE embraces and encourages their use.

GREEN POWER PROGRAM. Launched in 2001, PSE's Green Power Program allows customers to voluntarily purchase retail electric energy from qualified renewable energy resources. In 2009, PSE began working to increase participation in the program with 3Degrees, a third-party renewable energy credits (REC) broker that has developed and refined education and outreach techniques while working with other utility partners across the country. Since then, the program has grown to over 60,000 participants by the end of 2019. In addition, the number of megawatt-hours purchased increased by approximately 5 percent from 2017 to 2018 and 9.6 percent from 2018 to 2019, ending the period with sales amounting to 526,195 MWhs in 2019.

Top 10

PSE has been recognized as one of the country's top 10 utilities for Renewable Energy Sales and Total Number of Green Power Participants by the National Renewable Energy Laboratory since 2005.

Figure D-10: Green Power Megawatt-hours Sold, 2002-2019



The Green Power Program has built a portfolio of RECs generated from a wide variety of technologies. In 2017, PSE issued an RFQ that resulted in competitively awarding multi-year REC contracts to Bonneville Environmental Foundation and 3Degrees to help supply the balance of our Green Power program portfolio needs for up to three years, beginning in 2018 and expiring at the end of 2020. These suppliers provide the program with RECs primarily from Pacific Northwest renewable energy facilities. In mid-2020, PSE issued an RFQ seeking RECs to supply the Green Power program for the years 2021-2023. In addition, the Green Power Program directly purchases RECs from small, local and regional producers in order to support the development of small-scale renewable resources. These have included FPE Renewables, Farm Power Rexville, Edaleen Cow Power, Van Dyk-S Holsteins, Rainier Biogas, 3Bar G Community Wind, First Up! Knudson Community Wind, Ellensburg Community Solar, Swauk Wind and LRI Landfill Gas. Some of our small-scale solar contracts such as Skagit Community Solar, APSB Community Solar, Maple Hall Community Solar, Anacortes Library Community Solar and Greenbank Community Solar expired at the end of 2020. Many of these entities also provide power to PSE under the Schedule 91 contracts discussed above.

The increase in the number of utility-scale solar projects in Idaho and Oregon has allowed PSE to dramatically increase the number of RECs sourced from solar projects. PSE's preference is to source RECs first from projects located in Washington, and then from Oregon and Idaho. However, the supply of Pacific Northwest RECs continues to tighten as voluntary program sales have grown, and more resources are dedicated to serving compliance targets. This has made it more difficult to source all of our supply from this region. In an effort to maintain current program pricing, we have begun sourcing from other locations in the WECC, including Montana, Utah, Colorado, California and British Columbia. We believe this trend will continue as CETA compliance increases demand for renewable energy in the region.

GREEN POWER COMMUNITY GRANTS. Over the past 13 years, the Green Power Program has also committed over $1,850,000 in grant funding to 15 cities, 6 community service organizations and 10 low income multi-family housing agencies for solar demonstration projects. For example, in 2019, PSE awarded solar grants to 10 non-profit organizations specializing in low income or transitional multi-family housing. Anacortes Housing Authority, Community Youth Services, Family Support Center of South Sound, Homes First, King County Housing Authority, Kulshan Community Land Trust, Lummi Nation Housing Authority, Muckleshoot Housing Authority, Lydia Place and Opportunity Council received over $575,000 that resulted in more than 219 new kW of installed solar. In 2020, PSE issued a solicitation to award up to $1,000,000 in grant funding for solar installations to non-profits, public housing authorities or tribal entities serving low income or Black, Indigenous and People of Color (BIPOC) community members in PSE's electric service area. Projects are expected to be installed in 2021.

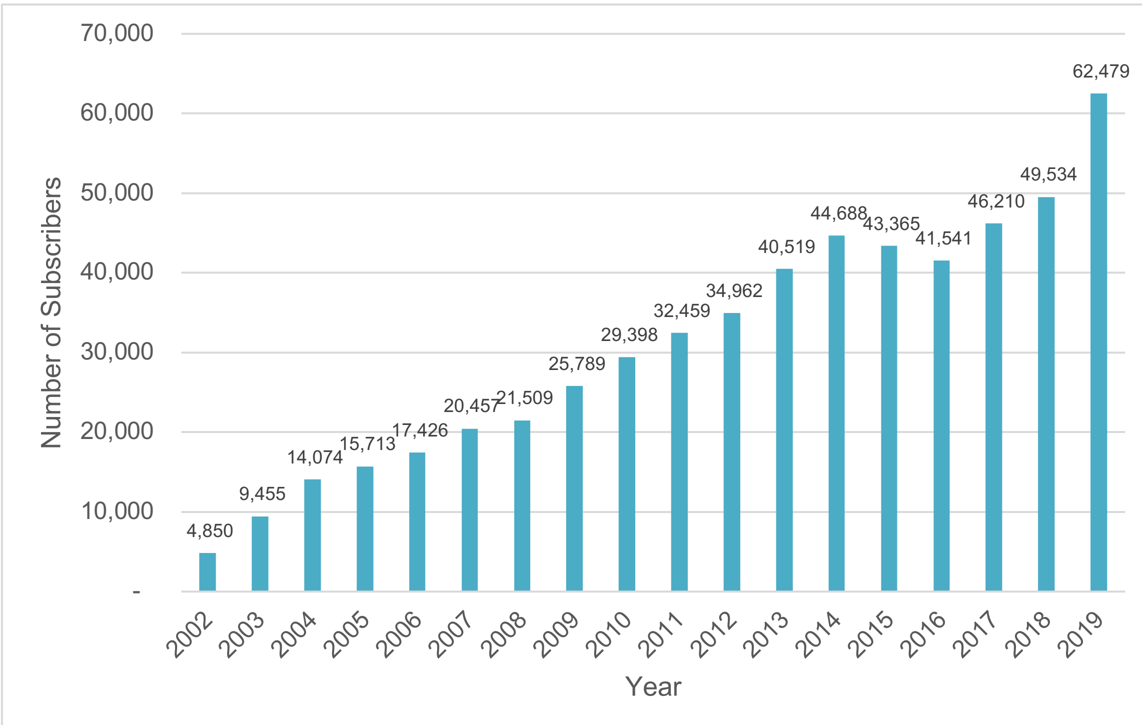
GREEN POWER RATES. In September 2016, PSE received approval from the WUTC to reduce Green Power rates. The standard rate for green power dropped from $0.0125 per kWh to $0.01 per kWh. Customers can purchase 200 kWh blocks for $2.00 per block with a two-block minimum or choose to participate in the "100% Green Power Option" introduced in 2007. This option adjusts the amount of the customer's monthly green power purchase to match their monthly electric usage. The large-volume green power rate dropped from $0.006 per kWh to $0.0035 per kWh for customers who purchase more than 1,000,000 kWh annually. This product has attracted approximately 30 customers since it was introduced in 2005.

In 2019, the average residential customer purchase was 718 kWh per month, and the average commercial customer purchase was 1,957 kWh. The average 2019 large-volume purchase under Schedule 136, by account, was 31,260 kWh per month.

SOLAR CHOICE. In September 2016, the WUTC approved PSE's Solar Choice program, a renewable energy product offering for residential and small to mid-size commercial customers. Similar to the Green Power program, Solar Choice allows customers to voluntarily purchase retail electric energy from qualified renewable energy resources; but in this case, all of the resources supplied are solar energy facilities located in Washington, Oregon and Idaho. Customers can elect to purchase solar in $5.00 blocks for 150 kilowatt-hours. The purchase is added to their monthly bill. The program was officially launched to customers in April 2017, and current participation stands at 7,654 participants. Collectively, these customers purchased 18,563 megawatt-hours of solar energy in 2019, a 112 percent increase from 2018 to 2019.
Figure D-11 illustrates the number of subscribers in our Green Power and Solar Choice offerings by year. Of our 62,479 Green Power and Solar Choice subscribers at the end of 2019, 61,554

were residential customers, 856 were commercial accounts, and 79 accounts were assigned under the large-volume commercial agreement. Cities with the most residential and commercial participants include Bellingham with 7,350, Olympia with 6,909 and Kirkland with 4,564.

Figure D-11: Green Power and Solar Choice Subscribers, 2002-2019



GREEN DIRECT. The Green Direct program launched on September 30, 2016 after WUTC approval. Like the Green Power program and Solar Choice, Green Direct falls under the rules governing utility green pricing options found in Washington RCW 19.29A, Voluntary Option to Purchase Qualified Alternative Energy Resources. Green Direct is a product that allows the utility to procure and sell fully bundled renewable energy to large commercial (10,000 MWh per year or more of load in PSE's service area) and government customers from specified wind and solar resources.

For Phase I, PSE signed a 20-year power purchase agreement for the output from the 137 MW Skookumchuck Wind project in Lewis County. Customers could elect to enroll for terms of 10, 15 or 20 years. The customer continues to receive and pay for all of the standard utility services for safety and reliability. Customers are charged for the total cost of the energy from the new plant, but receive a credit for the energy-related power costs from the company.

Phase I of Green Direct held its first open enrollment period in November and December 2016, followed by a second open enrollment period that opened on May 1, 2017. By the end of June 2017, less than two months later, the wind facility was fully-subscribed with 21 customers. Enrollees include companies like Starbucks, Target Corporation and REI, and government entities like King County and the City of Olympia.

For Phase II, PSE issued a Request for Proposals to identify a new resource (or resources) in August 2017. In early 2018, PSE selected a 120 MW solar project to be built in south-central Washington that is expected to begin operations in 2021. Following selection, PSE proposed a blended rate of the Phase I wind project and Phase II solar project, which the WUTC approved in July 2018. Phase II enrollment opened on August 31 at 1:00 pm, and was completely subscribed by 16 customers; four were wait listed. PSE subsequently requested an expansion of the project size from 120 MW to 150 MW, which the WUTC approved. The expansion allowed all 20 customers to participate. Phase II customers include T-Mobile, Amazon, Walmart, UW Bothell, Bellevue College, six Washington State agencies, the Issaquah School District, Providence Health & Services, Kaiser Permanente, Port of Bellingham, the cities of Kent and Redmond, and several customers from Phase I requesting additional supply.

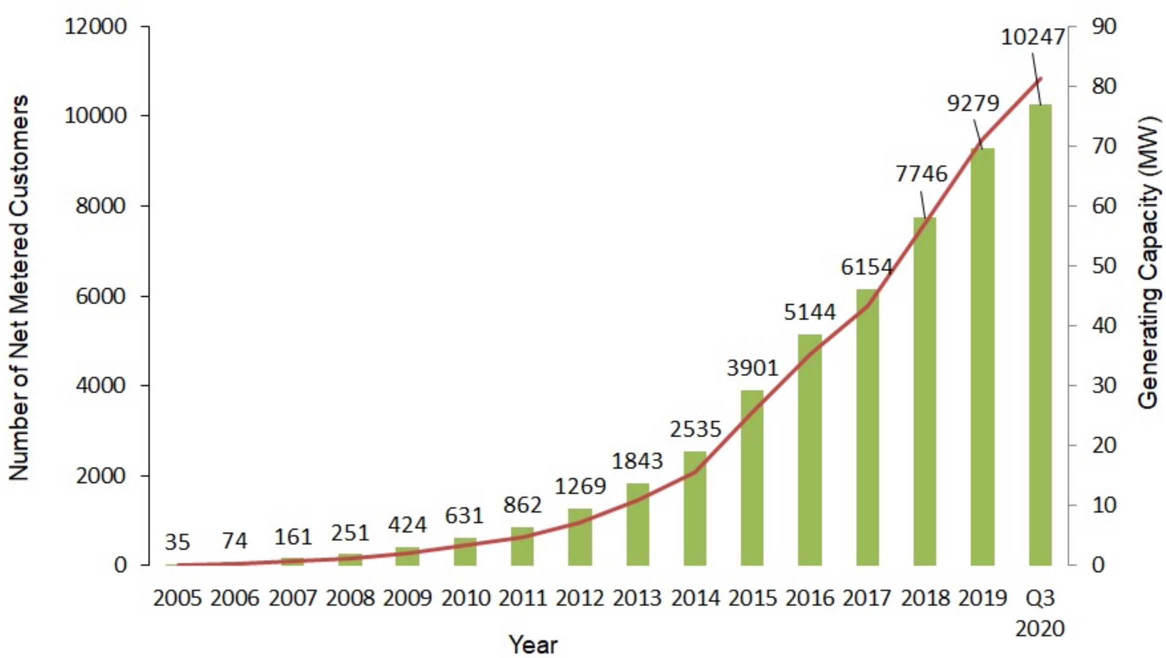
Customer Connected Renewables Programs

PSE offers two customer programs for customers who install their own small-scale generation, a net metering program and the Washington State Renewable Energy Production Incentive Program. These are not mutually exclusive, and the majority of customer-generators were enrolled in both programs until the Production Incentive Program closed to new participants in 2019.

The **NET METERING PROGRAM**, defined in Rate Schedule 150 and governed by RCW 80.60, began in 1999, and was most recently updated by Washington State Senate bill ESSB 5223 on July 28, 2019. Net metering provides a way for customers who generate their own renewable electricity to offset the electricity provided by PSE. The amount of electricity that the customer generates and sends back to the grid is subtracted from the amount of electricity provided by PSE, and the net difference is what the customer pays for on a monthly basis. A kWh credit is carried over to the next month if the customer generates more electricity than PSE supplies over the course of a month. The “banked” energy can be carried over until March 31, when the account is annually reset to zero according to state law. The interconnection capacity allowed under net metering is 100 kW AC.

Customer interest in small-scale renewables has increased significantly over the past 20 years, as Figure D-12 shows. The program has doubled the number of participating customers in the last four years, with strong growth continuing even after the closure of the State Production Incentive Program. In August of 2020, PSE celebrated its 10,000th net metered customer.

Figure D-12: Net Metered Customers, 1999-2020



The vast majority of customer systems (99 percent) are solar photovoltaic (PV) installations with an average generating capacity of 8 kW, but there are also small-scale hydroelectric generators and wind turbines. These small-scale renewable systems are distributed over a wide area of PSE's service territory. By mid-2020, PSE was net metering more than 80 MW (AC) of generating capacity.

Customer preference along with declining prices and federal tax incentives continues to drive customer solar PV adoption. Residential customers were 95 percent of all solar PV by number and 87 percent by nameplate capacity. In 2019, PSE revised Schedule 150 and streamlined the interconnection and net metering application process. PSE continues to examine our processes to allow for customer generation to scale up.

Figure D-13: Interconnected System Capacity by Type of System, as of Q3 2020

SYSTEM TYPE	NUMBER OF SYSTEMS	AVERAGE CAPACITY PER SYSTEM TYPE (kW [MW])	SUM OF ALL SYSTEMS BY TYPE (kW [MW])
Hybrid: solar/wind	16	9.3 [0.0093]	184 [0.184]
Micro hydro	6	15.7 [0.0177]	101 [0.101]
Solar array	10,196	8.0 [0.008]	80,993 [81]
Wind turbine	29	2.7 [0.0027]	80 [0.08]
Total	**10,247**	**8.0 [0.008]**	**81,359 [81.359]**

Figure D-14: Net Metered Systems by County

COUNTY	NUMBER OF NET METERS
Whatcom	2,126
King	3,342
Skagit	954
Island	485
Kitsap	1,031
Thurston	1,189
Kittitas	576
Pierce	536
Total	**10,247**

RENEWABLE ENERGY PRODUCTION INCENTIVE PAYMENT PROGRAM. The Washington State Renewable Energy Production Incentive Program is a production-based financial incentive for customers with solar, wind and bio-digester generating systems. PSE has voluntarily administered this state incentive to qualified customers under Schedule 151 since 2005.

In order for a PSE customer-generator to participate in Schedule 151, they must:

- Be a PSE customer with a valid interconnection agreement with PSE for the operation of their grid-connected renewable energy system.
- Have a system that includes production metering capable of measuring the energy output of the renewable energy system.
- Be certified (as named on the PSE account) by the Washington State Program Administrator as eligible for annual incentive payments.

In June 2019, the Washington State Program Administrator issued notice that this program's budget was fully obligated and PSE formally withdrew our voluntary participation effective December 12, 2019. PSE continues to administer annual incentive payments to all certified program participants, but customers installing new solar systems after December 12, 2019 are not eligible to participate in this program. Thus, the State Production Incentive Program is no longer a driver of solar energy adoption.

Annual Production Reporting and Payments: Annually, PSE measures and reports the kilowatt hours generated by participants' renewable energy systems and makes incentive payments to eligible customers as determined by the Washington State Program Administrator.

Legacy participants (those certified to participate by the Department of Revenue prior to October 1, 2017) with valid certifications will continue to receive payments of up to $5,000 per year for electricity produced through June 30, 2020 at rates ranging from $0.14 to $0.504 per kWh. Participants who obtained state certification on or after October 1, 2017 and who maintain ongoing eligibility requirements are eligible for up to eight years of annual incentive payments on kilowatt-hours generated from July 1, 2017 through June 30, 2029. The incentive rate for these participants ranges from $0.02 to $0.21 per kWh based on system size, technology and the date of certification.

Participant eligibility, rates, terms, payment limits and incentive payment amounts are determined by the Washington State Program Administrator.

Through 2019, PSE had administered to our customers over $72 million in production incentive payments. These payments are recovered through state tax credits. PSE expected to issue another $19 million in payments to approximately 8,000 participating customers. 2020 was the final payment year for 5,300 legacy program participants.

3. ELECTRIC RESOURCE ALTERNATIVES

This overview of alternatives for electric power generation describes both mature technologies and new methods of power generation, including those with near- and mid-term commercial viability. Within each section, resources are listed alphabetically.

COST ASSUMPTIONS. The generic resource costs for renewable, energy storage and thermal resources described in the following pages were aggregated from publicly available data sources including the National Renewable Energy Laboratory (NREL), the U.S. Energy Information Administration, Lazard, the Northwest Power and Conservation Council, various other National Laboratories and regional Integrated Resource Plans. Aggregated costs were then informed and adjusted through the stakeholder feedback process. Generic resource cost assumptions, including all data sources and averaging assumptions are available for review on the PSE IRP website.[16]

OPERATING CHARACTERISTICS. Generic resource operating characteristics were informed by PSE's experience, solar and wind data published by the NREL, and the Generic Resource Costs for Integrated Resource Planning report completed by consultant HDR for PSE in 2018, available for review on the PSE IRP website.[17]

16 / https://oohpseirp.blob.core.windows.net/media/Default/documents/Generic_Resource_Cost_Summary_PSE%202021%20IRP_post-feedback_v5.xlsx
17 / https://oohpseirp.blob.core.windows.net/media/Default/PDFs/HDR_Report_10111615-0ZR-P0001_PSE%20IRP_Rev4%20-%2020190123).pdf

Demand-side Resource Costs and Technologies

Demand-side resource (DSR) alternatives are analyzed in a Conservation Potential Assessment and Demand Response Assessment (CPA) to develop a supply curve that is used as an input to the portfolio analysis. The portfolio analysis then determines the maximum amount of energy savings that can be captured without raising the overall electric or natural gas portfolio cost. This identifies the cost-effective level of DSR to include in the portfolio.

PSE included the following demand-side resource alternatives in the CPA that was performed by The Cadmus Group for this IRP.

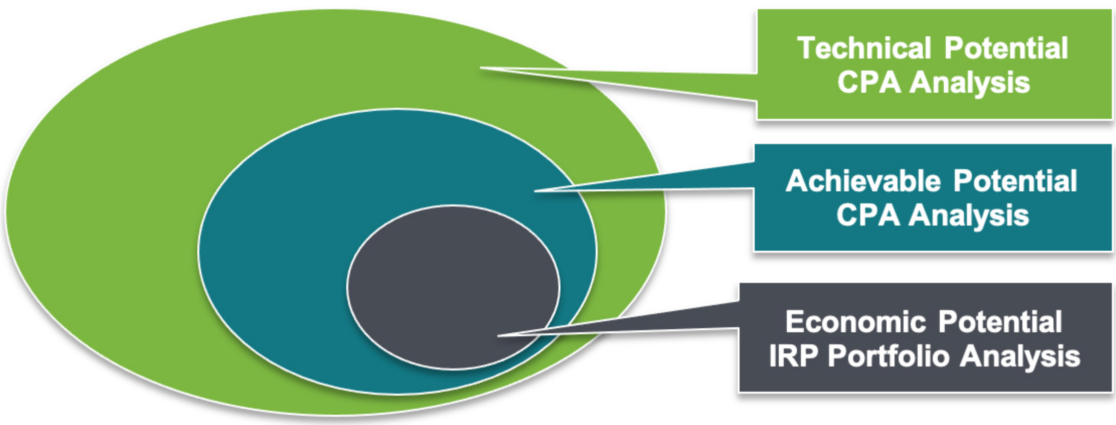
- **ENERGY EFFICIENCY MEASURES.** This label is used for a wide variety of measures that result in a smaller amount of energy being used to do a given amount of work. These include retrofitting programs such as heating, ventilation and air conditioning (HVAC) improvements, building shell weatherization, lighting upgrades and appliance upgrades.
- **DEMAND RESPONSE (DR).** Demand response resources are comprised of flexible, price-responsive loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost.
- **DISTRIBUTED GENERATION.** Distributed generation refers to small-scale electricity generators located close to the source of the customer's load on customer's side of the utility meter. This includes combined heat and power (CHP) and rooftop solar.[18]
- **DISTRIBUTION EFFICIENCY (DE).** This involves conservation voltage reduction (CVR) and phase balancing. Voltage reduction is the practice of reducing the voltage on distribution circuits to reduce energy consumption, as many appliances and motors can perform properly while consuming less energy. Phase balancing eliminates total current flow energy losses.
- **GENERATION EFFICIENCY.** This involves energy efficiency improvements at the facilities that house PSE generating plant equipment, and where the loads that serve the facility itself are drawn directly from the generator and not the grid. These loads are also called parasitic loads. Typical measures target HVAC, lighting, plug loads and building envelope end-uses.
- **CODES AND STANDARDS (C&S).** These are no-cost energy efficiency measures that work their way to the market via new efficiency standards set by federal and state codes and standards. Only those that are in place at the time of the CPA study are included.

18 / In this IRP distributed solar PV is not included in the demand-side resources. Instead, it is handled as a direct no-cost reduction to the customer load. Solar PV subsidies are driving implementation and the subsidies are not fully captured with by the Total Resource Cost (TRC) approach that is used to determine the cost-effectiveness of DSR measures. Under the TRC approach, distributed solar PV is not cost effective and so is not selected in the portfolio analysis. Treating solar as a no-cost load reduction captures the adoption of this distributed generation resource by customers and its impact on loads more accurately.

Treatment of Demand-side Resource Alternatives

The conservation potential assessment and demand response assessment (CPA) performed for PSE by The Cadmus Group develops two levels of demand-side resource potential: technical potential and achievable technical potential. The IRP portfolio analysis then identifies the third level, economic potential. Figure D-15 shows the relationship between the technical, achievable and economic conservation potentials.

Figure D-15: Relationship between Technical, Achievable and Economic Potential



First, the CPA screened each measure for technical potential. This screen assumed all energy- and demand-saving opportunities could be captured regardless of cost or market barriers, which ensured the full spectrum of technologies, load impacts and markets were surveyed.

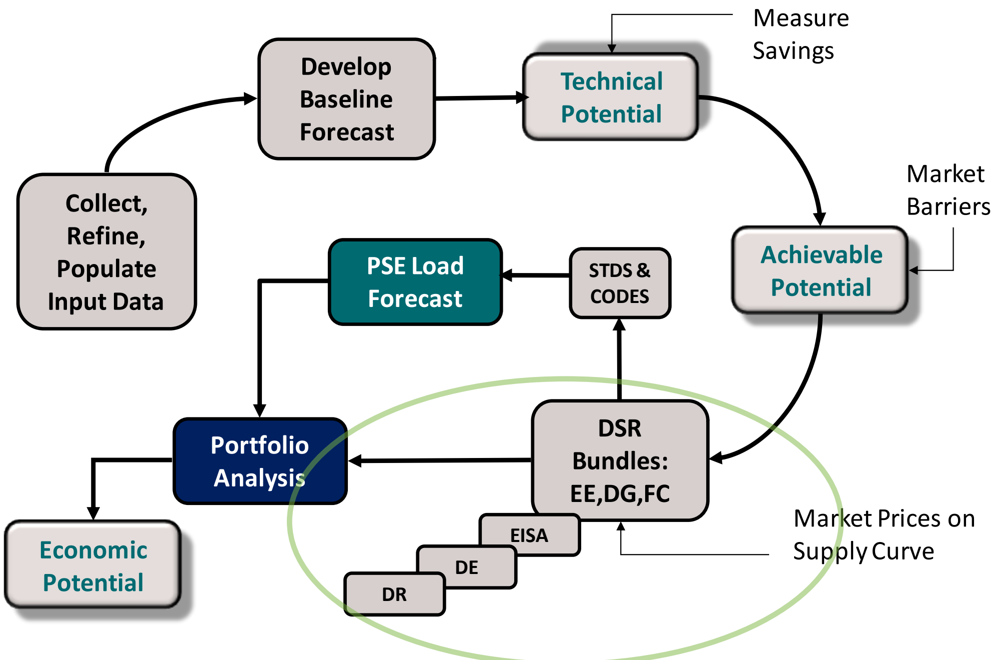
Second, market constraints were applied to estimate the achievable potential. To gauge achievability, Cadmus relied on customer response to past PSE energy programs, the experience of other utilities offering similar programs, and the Northwest Power and Conservation Council's most recent energy efficiency potential assessment. For this IRP, PSE assumed achievable electric energy efficiency potentials of 85 percent in existing buildings and 65 percent in new construction.

In the third step, the measures were combined into bundles based on levelized cost. This produces a conservation supply cost curve that is included in the IRP portfolio optimization analysis to identify the economic potential (cost-effectiveness) of the bundles.

Figure D-16 illustrates the methodology PSE used to assess demand-side resource potential in the IRP.

>>> See Appendix E, Conservation Potential Assessment and Demand Response Assessment, to access the Cadmus report.

Figure D-16: General Methodology for Assessing Demand-side Resource Potential

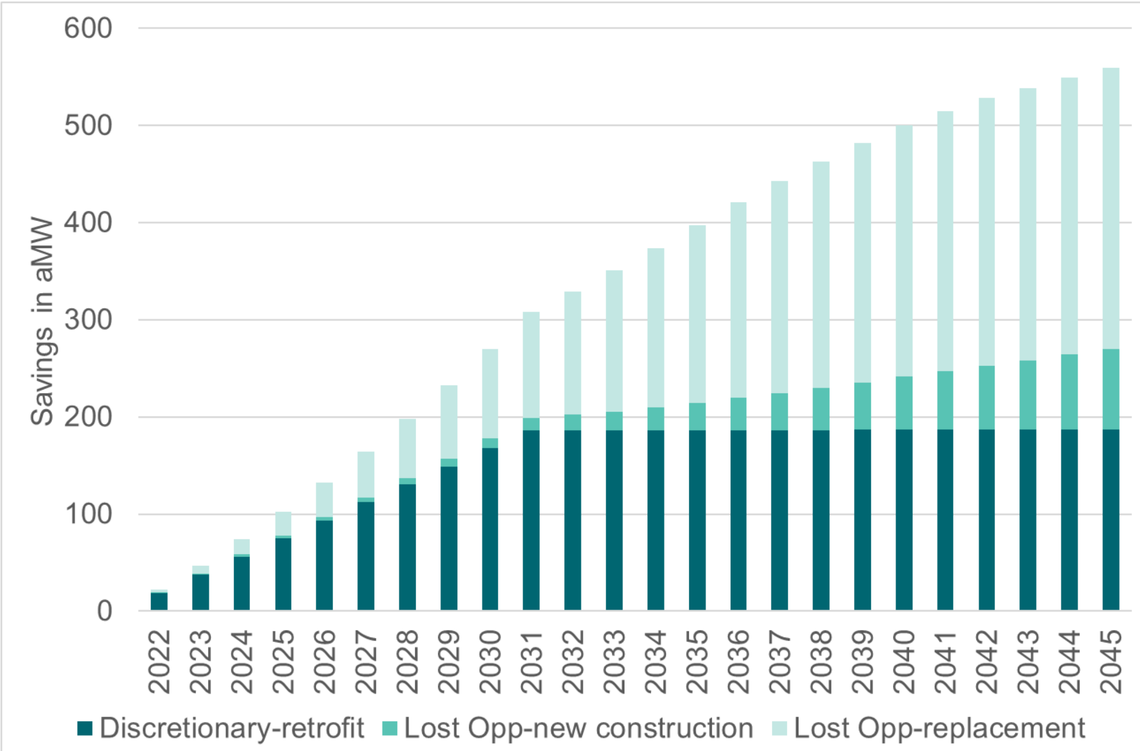


The tables and charts that follow summarize the results of the Cadmus Group's analysis of demand-side resources. Bundles 1 through 13 include energy efficiency and distributed generation. Each bundle adds measures to the bundle that preceded it. For a discussion of distribution efficiency (DE) bundles, see the section below. For the discussion of the Codes and Standards (C&S) bundles, see Appendix E, Conservation Potential Assessment report.

The savings potential for Bundles 1 through 13 consists of both retrofit and lost opportunity measures.[19] Figure D-17 shows the proportion of discretionary versus lost opportunity measures in the bundles.

19 |According to the Regional Technical Form: Lost opportunity measures are those that are available only during a specific window of time at a cost specific to the circumstances surrounding that instance of implementation, for example the replacement of equipment on failure of equipment or the addition of new equipment or facilities. Similarly, retrofit measures, also known as discretionary measures, are improvements to or replacements of systems that do not need to occur at the time of actual improvement or replacement.

Figure D-17: Discretionary versus Lost Opportunity Measures in Bundles 1 to 13



Distribution Efficiency

Plans for distribution efficiency have been updated in this IRP to reflect the changes in technology required to maintain power quality and stability as the role of distribution efficiency grows, while at the same time increasing amounts of distributed generation are entering the delivery system.

The original conservation voltage reduction (CVR) program PSE implemented in 2012-2013 utilized AMI meters that are now outdated and incompatible with the company-wide rollout of upgraded AMI technology that began in 2018. That rollout is expected to be completed in 2023. In the meantime, selected substations that have received the AMI upgrade will be able to participate in the current CVR program.

A second technology upgrade is planned as well. The current CVR program is a static form of CVR that cannot react to compensate for changes on the distribution system produced by distributed resources such as battery storage, solar generation and DR schemes. Because the static system cannot react and adjust to changing conditions on the distribution system, PSE is therefore investing in Automated Distribution Management System (ADMS) technology that can be programmed to automatically detect and anticipate changing conditions on the system. This will enable the system to react fast enough to prevent putting customers' power quality at risk.

Once the AMI and ADMS technologies are fully implemented, PSE will also have the operational control system necessary to transition the CVR program to full Volt-Var Optimization (VVO). ADMS will leverage AMI data at the end of line, with its own analytics and control intelligence to dynamically optimize power delivery within the distribution network, minimize losses and conserve energy. This builds upon dynamic voltage control by sensing and managing switched capacitors to optimize the power factor. VVO is a more sophisticated and extensive process than CVR, but relies on similar principles.

Completion of the AMI rollout is expected in 2023, and the ADMS software platform is expected to be completed in 2021. PSE expects to begin piloting VVO in 2021. From 2019-2021, we will continue implementing the current, static line drop compensation (LDC) CVR, but we expect we may continue to encounter complications and risks due to changes on the distribution system that are already occurring.

Eligible Substations: The current CVR program was put into place based on a study completed in 2007. According to that study, approximately 150 substations with at least 50 percent residential customers were identified as having the potential for energy savings using LDC CVR, based on typical customer usage patterns and the customer composition of the substations. Those 150 substations represented 52 percent of PSE's total 297 distribution substations and affected 67 percent of the PSE's customers.

An updated study is needed to confirm the number of substations which have the potential for cost-effective energy saving VVO. The implementation schedule and associated energy savings in Figures D-18 and D-19 below outline a projected number of substations to be completed each year and the cumulative savings expected.

Figure D-18: Implementation Schedule for Eligible Substations

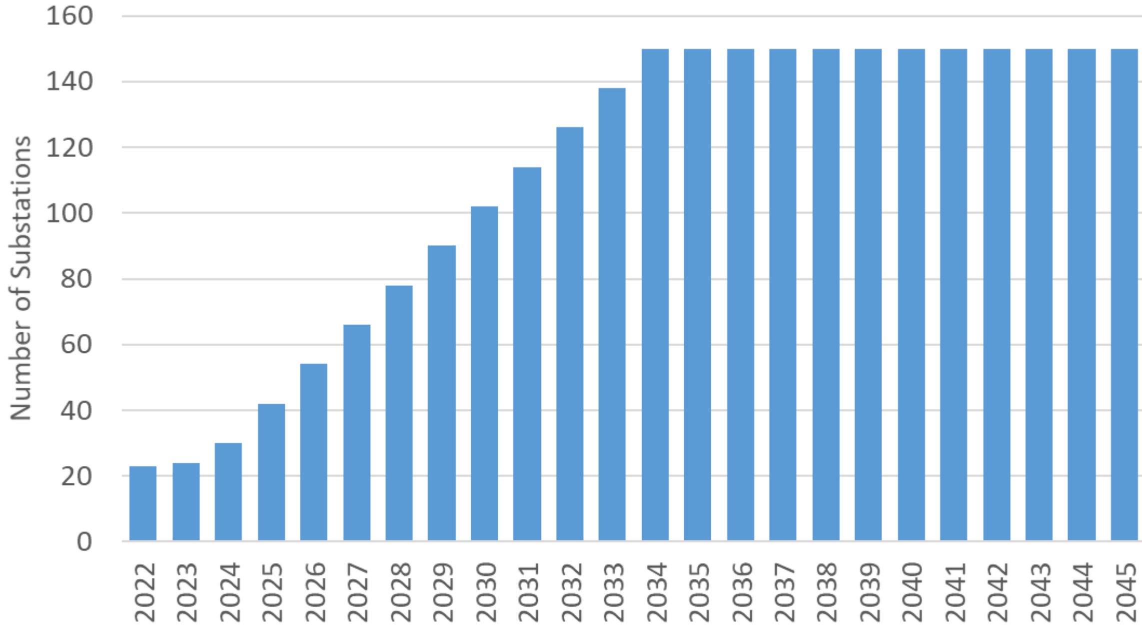


Figure D-19: Cumulative Savings in aMW from Distribution Efficiency (CVR+VVO)

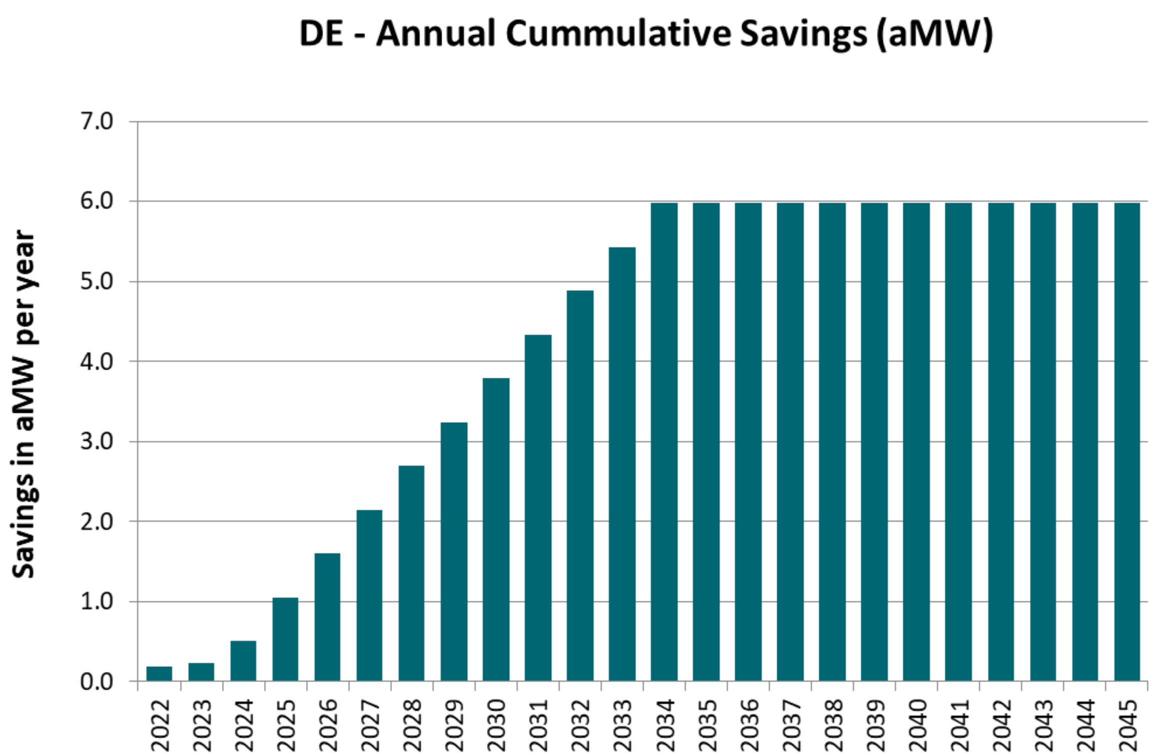


Figure D-20: Annual Energy Savings (aMW)

	Bundles (aMW)														
	1	2	3	4	5	6	7	8	9	10	11	12	13	DE	C&S
2022	3.7	1.8	1.2	0.2	0.5	0.2	0.6	0.5	1.2	0.2	0.1	0.1	1.3	0.5	21.8
2023	11.8	5.8	3.6	0.8	1.6	0.6	2.1	1.6	3.8	0.7	0.4	0.3	4.1	1.1	33.1
2024	20.4	10.0	6.2	1.4	2.7	1.0	3.8	3.1	6.9	1.4	0.7	0.5	7.2	1.7	44.8
2025	29.2	14.4	8.7	2.3	3.8	1.4	5.7	4.6	10.2	2.3	1.0	0.8	10.6	3.0	53.3
2026	38.3	18.8	11.2	3.3	4.9	1.7	7.9	6.2	13.7	3.4	1.5	1.0	14.4	4.3	60.5
2027	47.7	23.5	13.7	4.5	6.1	2.1	10.4	8.0	17.3	4.7	2.0	1.3	18.5	5.7	67.4
2028	57.6	28.6	16.2	6.0	7.4	2.5	13.2	10.0	21.0	6.3	2.7	1.6	23.2	7.0	73.9
2029	67.3	33.5	18.7	7.7	8.7	2.9	16.2	11.9	24.7	8.1	3.4	1.8	28.1	8.3	80.1
2030	77.2	38.6	21.2	9.6	10.0	3.3	19.3	13.9	28.4	10.3	4.2	2.2	33.5	9.6	86.5
2031	87.5	43.8	23.7	11.8	11.4	3.7	22.7	16.2	32.2	12.9	5.2	2.5	39.3	10.9	93.4
2032	95.0	47.5	25.2	14.0	12.4	4.0	25.9	18.3	35.4	15.8	6.1	2.8	44.4	12.2	99.1
2033	98.6	49.1	25.2	16.2	12.8	4.0	28.3	19.8	37.6	18.9	6.9	3.0	48.2	13.5	104.2
2034	102.6	50.8	25.3	18.5	13.3	4.1	31.0	21.5	39.9	22.3	7.8	3.3	52.4	14.8	110.3
2035	106.7	52.7	25.4	20.7	13.9	4.1	33.7	23.5	42.3	26.0	8.7	3.5	56.7	14.8	117.1
2036	111.0	54.7	25.6	23.0	14.5	4.2	36.7	25.6	44.8	30.0	9.7	3.8	61.2	14.8	123.0
2037	114.7	56.2	25.6	25.2	15.0	4.3	39.3	27.3	46.9	34.0	10.6	4.1	65.4	14.8	128.7
2038	118.7	57.6	25.7	27.4	15.6	4.3	42.0	28.6	48.1	37.9	11.5	4.3	69.4	14.8	134.4
2039	122.8	59.0	25.7	29.6	16.2	4.4	44.7	29.6	48.6	41.8	12.3	4.6	73.1	14.8	140.3
2040	126.9	60.5	25.8	31.6	16.8	4.5	47.3	30.8	49.2	45.8	13.2	4.9	76.8	14.8	145.9
2041	129.6	61.6	25.8	32.4	17.3	4.5	49.1	31.7	49.4	49.5	14.0	5.1	79.9	14.8	151.7
2042	132.6	62.8	25.9	32.6	17.9	4.6	50.5	32.7	49.7	53.2	14.7	5.4	82.8	14.8	157.4
2043	135.6	64.1	25.9	32.7	18.5	4.6	51.7	33.7	49.9	56.3	15.0	5.6	84.5	14.8	163.0
2044	139.1	65.6	26.0	32.9	19.1	4.7	53.1	34.9	50.3	59.1	15.1	5.9	85.8	14.8	168.4
2045	141.7	66.6	25.9	32.9	19.6	4.8	54.1	35.9	50.4	61.4	15.1	6.1	86.4	14.8	174.1

Figure D-21: Total December Peak Reduction (MW)

	Bundles (MW)														
	1	2	3	4	5	6	7	8	9	10	11	12	13	DE	C&S
2022	12.1	7.2	3.7	0.7	2.7	0.9	2.7	1.3	4.1	0.6	0.5	0.3	5.3	1.2	37.0
2023	24.8	14.7	7.3	1.5	5.4	1.7	5.7	3.0	8.6	1.6	1.1	0.7	11.2	1.5	61.4
2024	38.0	22.5	11.0	2.6	8.1	2.6	9.1	4.8	13.4	2.9	2.0	1.0	17.6	2.2	80.2
2025	51.6	30.4	14.7	4.0	10.9	3.4	12.7	6.7	18.4	4.7	3.0	1.4	24.9	3.9	92.1
2026	65.6	38.5	18.4	5.6	13.7	4.2	16.7	8.7	23.5	6.8	4.2	1.7	32.9	5.1	107.0
2027	80.2	47.0	22.1	7.5	16.7	5.1	21.2	10.8	28.7	9.6	5.7	2.1	42.0	6.4	120.9
2028	95.2	55.8	25.8	9.8	19.7	6.0	26.0	13.2	34.0	13.0	7.4	2.5	52.0	7.7	145.6
2029	110.3	64.5	29.5	12.4	22.7	6.8	31.0	15.4	39.3	17.1	9.4	2.9	62.8	8.9	158.9
2030	126.0	73.5	33.2	15.4	25.8	7.6	36.3	17.9	44.7	22.0	11.7	3.3	74.7	10.2	163.0
2031	142.1	82.6	36.9	18.6	29.1	8.5	41.9	20.5	50.1	27.6	14.1	3.7	87.4	11.5	168.7
2032	147.8	85.3	37.0	21.8	29.9	8.5	45.5	22.3	52.5	33.6	16.5	3.9	96.2	12.8	180.6
2033	153.9	87.7	37.1	25.0	30.6	8.6	48.9	23.8	54.8	40.4	18.9	4.2	105.4	14.1	199.0
2034	160.5	90.6	37.3	28.4	31.5	8.6	52.7	25.8	57.2	47.7	21.3	4.5	115.0	15.4	222.2
2035	166.8	93.3	37.5	31.5	32.3	8.7	56.5	27.9	59.6	55.4	23.8	4.8	124.5	14.6	236.9
2036	173.0	95.8	37.7	34.7	33.2	8.7	60.2	30.0	62.0	63.5	26.2	5.0	134.1	14.6	224.7
2037	179.3	98.1	37.7	37.9	34.1	8.8	63.8	31.6	64.1	71.7	28.7	5.3	143.8	14.6	236.9
2038	185.8	100.3	37.7	41.2	35.1	8.9	67.6	32.8	64.8	79.8	31.2	5.6	153.0	14.6	248.3
2039	192.5	102.4	37.8	44.4	36.1	8.9	71.2	34.0	65.5	88.1	33.5	5.8	161.6	14.6	271.2
2040	198.1	104.3	37.9	46.7	36.9	9.0	74.4	35.3	66.1	96.3	35.8	6.1	169.9	14.6	296.2
2041	203.3	106.2	37.9	47.2	37.9	9.0	76.6	36.4	66.5	104.7	38.2	6.4	177.8	14.6	292.8
2042	208.3	108.1	37.9	47.5	38.8	9.1	78.5	37.6	66.8	112.2	40.0	6.6	183.7	14.6	290.3
2043	213.3	110.1	38.0	47.6	39.5	9.2	80.1	38.8	67.2	116.6	40.0	6.9	184.9	14.6	302.1
2044	218.7	112.3	38.0	47.8	40.4	9.3	81.9	40.2	67.7	121.2	40.2	7.2	186.7	14.6	325.8
2045	223.7	114.1	38.0	47.9	41.2	9.3	83.5	41.4	68.1	125.6	40.2	7.4	188.0	14.6	354.1

The DSR December peak reduction is based on the average of the very heavy load hours (VHLH). The VHLH method takes the average of the five-hour morning peak from hour ending 7 a.m. to hour ending 11 a.m. and the five-hour evening peak from hour ending 6 p.m. to hour ending 10 p.m. Monday through Friday. The system demand peaked during the evening hours and correspondingly the demand-side resource peaks were chosen to be coincident with those evening system peak hours.

Figure D-22: Annual Costs (dollars in thousands)

(Codes and Standards has no cost and is considered a must-take bundle.)

	Bundles ($'000)													
	1	2	3	4	5	6	7	8	9	10	11	12	13	DE
2022	$3,892	$14,579	$13,849	$2,855	$7,341	$2,949	$12,265	$11,739	$32,508	$6,044	$3,789	$4,260	$253,744	$2,450
2023	$4,456	$16,015	$13,875	$3,744	$7,573	$3,032	$15,121	$15,469	$38,664	$8,988	$4,867	$4,436	$263,266	$2,700
2024	$4,313	$16,818	$13,891	$4,603	$7,797	$3,034	$17,609	$17,750	$42,756	$11,803	$5,940	$4,623	$272,897	$3,270
2025	$4,449	$16,870	$13,892	$5,673	$7,969	$2,921	$19,528	$17,875	$45,311	$14,627	$7,317	$4,771	$283,391	$5,490
2026	$4,718	$17,775	$13,905	$6,779	$8,263	$2,966	$22,357	$19,702	$47,244	$17,658	$8,691	$5,024	$295,726	$6,090
2027	$5,052	$18,637	$13,918	$8,148	$8,610	$3,014	$25,215	$21,434	$48,468	$21,677	$10,355	$5,327	$310,353	$6,690
2028	$5,404	$19,548	$13,925	$9,661	$8,995	$3,093	$27,962	$23,623	$49,350	$25,827	$12,128	$5,696	$325,699	$7,290
2029	$5,570	$19,178	$13,911	$11,033	$9,180	$2,961	$28,866	$21,403	$49,538	$30,455	$13,887	$5,822	$337,674	$7,890
2030	$6,054	$20,295	$13,913	$12,570	$9,649	$3,094	$31,667	$24,708	$50,292	$35,746	$15,620	$6,271	$354,541	$8,490
2031	$6,483	$20,106	$13,902	$13,799	$10,025	$3,160	$33,625	$26,678	$50,788	$40,908	$17,023	$6,612	$368,456	$9,090
2032	$3,187	$6,840	$629	$13,117	$3,267	$418	$24,695	$19,903	$31,880	$44,259	$15,151	$4,948	$137,645	$9,690
2033	$3,260	$5,999	$630	$13,595	$3,207	$247	$23,882	$15,919	$31,569	$48,716	$15,828	$4,703	$140,718	$10,290
2034	$3,968	$7,510	$674	$13,933	$3,733	$493	$26,666	$22,065	$32,414	$53,435	$16,284	$5,210	$153,873	$10,890
2035	$4,333	$7,471	$692	$13,489	$3,971	$576	$27,421	$24,135	$32,703	$56,968	$16,418	$5,341	$159,132	$7,650
2036	$4,490	$6,827	$693	$13,401	$3,958	$513	$27,007	$22,734	$32,506	$59,827	$16,407	$5,190	$159,094	$7,650
2037	$4,409	$6,042	$303	$13,237	$3,778	$367	$25,713	$17,088	$27,103	$60,962	$16,381	$4,885	$155,776	$7,650
2038	$4,682	$5,429	$214	$13,290	$3,956	$461	$26,376	$10,793	$6,096	$56,491	$15,508	$5,043	$134,395	$7,650
2039	$4,830	$5,239	$213	$13,288	$4,049	$505	$25,532	$11,995	$6,279	$57,191	$15,145	$5,105	$126,308	$7,650
2040	$4,919	$5,414	$212	$9,910	$4,104	$534	$22,761	$12,723	$6,389	$57,704	$15,116	$5,139	$127,299	$7,650
2041	$4,776	$4,822	$199	$1,270	$3,952	$433	$15,285	$10,004	$3,298	$57,974	$15,083	$4,918	$119,554	$7,650
2042	$4,865	$5,146	$207	$1,102	$4,033	$495	$13,272	$11,597	$3,173	$54,249	$11,749	$5,014	$102,142	$7,650
2043	$4,858	$5,030	$208	$449	$3,628	$503	$12,019	$11,816	$3,190	$37,667	$228	$5,007	$53,941	$7,650
2044	$4,955	$5,283	$217	$511	$3,676	$571	$12,613	$13,565	$3,394	$36,919	$39	$5,116	$55,811	$7,650
2045	$4,745	$4,650	$202	$421	$3,508	$473	$11,623	$11,040	$3,079	$36,600	$36	$4,901	$51,404	$7,650

Demand Response

Demand response (DR) is a strategy designed to decrease load on the grid during times of peak use. It involves modifying the way customers use energy – particularly when they use it. For instance, businesses might work with PSE to voluntarily adjust their operations during a specified time range. Residential customers might automate their usage with smart thermostats or water heaters. While there are often financial incentives to participate in DR pilots and programs, it is also a way for both PSE and customers to increase efficiency and reduce their carbon footprints.

Demand response programs are voluntary, and once enrolled, customers usually receive notifications in advance of forecasted peak usage times. Depending on the program, this might mean that their thermostat automatically warms their home or building earlier than usual. Because of the remote function of demand response, no action is required from customers to initiate their reduction in load, and they can always choose to opt out of an event.

Demand response programs are organized into four categories. These include:

- Direct Load Control (DLC)
- Commercial and Industrial (C&I) Curtailment
- Dynamic Pricing or Critical Peak Pricing (CPP)
- Behavioral DR

Figures D-23a and 23b provide the total winter and summer peak reduction potential for each program, and Figures D-24a and 24b show the costs for each of those programs. In these tables, the numbers across the top represent the 16 different DR programs analyzed, as follows:

1. Residential CPP-No Enablement
2. Residential CPP-With Enablement
3. Residential DLC Heat-Switch
4. Residential DLC Heat-BYOT
5. Residential DLC ERWH-Switch
6. Residential DLC ERWH-Grid-Enabled
7. Residential DLC HPWH-Switch
8. Residential DLC HPWH-Grid-Enabled
9. Small Commercial DLC Heat-Switch
10. Medium Commercial DLC Heat-Switch
11. Commercial & Industrial Curtailment-Manual
12. Commercial & Industrial Curtailment-AutoDR
13. Commercial CPP-No Enablement
14. Commercial CPP-With Enablement

Figure D-23a: Demand Response Programs, Total Winter Peak Reduction (MW)

	DR Winter Programs (MW)															
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	4	0	5	1	0	0	1	0	0	0	0	0	0	1
2024	0	0	8	0	9	2	0	0	1	1	0	0	0	0	0	3
2025	5	0	16	0	18	5	0	0	2	2	1	1	0	0	1	4
2026	10	0	25	1	25	10	0	0	3	3	1	1	1	0	1	5
2027	20	1	34	1	31	16	0	0	5	3	2	2	1	1	2	7
2028	30	1	42	1	35	24	1	0	6	4	2	2	1	1	2	7
2029	41	1	43	2	32	27	0	0	6	4	2	2	1	1	2	7
2030	52	2	43	2	29	31	0	0	6	4	2	3	1	1	3	7
2031	53	2	44	2	25	35	0	1	6	5	2	3	1	1	3	7
2032	54	2	44	3	22	39	0	1	6	5	3	3	1	1	3	7
2033	54	2	45	3	18	43	0	1	6	5	3	3	1	1	4	7
2034	55	2	45	3	15	47	0	1	6	5	3	3	1	1	4	7
2035	56	2	46	3	11	51	0	1	6	5	3	3	1	1	4	8
2036	57	2	46	3	10	53	0	1	6	5	3	3	1	1	5	8
2037	58	2	47	3	10	54	0	1	6	5	3	3	1	1	5	8
2038	59	2	47	3	10	54	0	1	6	5	3	3	1	1	6	8
2039	60	2	48	3	10	55	0	1	6	5	3	3	1	1	6	8
2040	60	2	48	3	10	55	0	1	6	5	3	3	1	1	6	8
2041	61	2	48	3	10	56	0	1	6	5	3	3	1	1	7	8
2042	62	2	49	3	10	56	0	1	6	5	3	3	1	1	7	8
2043	63	2	49	3	10	57	0	1	7	5	3	3	1	1	8	9
2044	64	2	50	3	11	57	0	1	7	5	3	3	1	1	8	9
2045	64	2	50	3	11	58	0	1	7	5	3	3	1	1	9	9

Figure D-23b: Demand Response Programs, Total Summer Peak Reduction (MW)

	DR Summer Programs (MW)															
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	2	0	5	1	0	0	1	1	0	0	0	0	0	1
2024	0	0	4	2	9	2	0	0	1	3	1	1	0	0	0	2
2025	3	0	8	3	18	5	0	0	3	6	1	1	1	1	1	2
2026	6	0	12	6	25	10	0	0	4	9	2	2	1	1	1	3
2027	12	0	16	11	31	16	0	0	6	12	2	3	1	2	2	4
2028	19	0	20	14	35	24	1	0	8	16	3	3	1	3	2	4
2029	25	1	20	17	32	27	0	0	8	16	3	3	1	3	2	4
2030	32	1	21	20	29	31	0	0	8	16	3	3	1	3	3	4
2031	32	1	21	22	25	35	0	1	8	16	3	3	1	3	3	4
2032	33	1	21	24	22	39	0	1	8	16	3	3	1	3	3	4
2033	33	1	21	26	18	43	0	1	8	16	3	3	1	3	4	5
2034	34	1	22	27	15	47	0	1	8	17	3	3	2	3	4	5
2035	34	1	22	28	11	51	0	1	8	17	3	3	2	3	4	5
2036	35	1	22	28	10	53	0	1	8	17	3	3	2	3	5	5
2037	35	1	22	29	10	54	0	1	8	17	3	4	2	3	5	5
2038	36	1	22	29	10	54	0	1	8	17	3	4	2	3	6	5
2039	36	1	23	29	10	55	0	1	8	17	4	4	2	3	6	5
2040	37	1	23	30	10	55	0	1	8	18	4	4	2	3	6	5
2041	37	1	23	30	10	56	0	1	8	18	4	4	2	3	7	5
2042	38	1	23	30	10	56	0	1	9	18	4	4	2	3	7	5
2043	38	1	24	31	10	57	0	1	9	18	4	4	2	3	8	5
2044	39	1	24	31	11	57	0	1	9	18	4	4	2	3	8	5
2045	39	1	24	31	11	58	0	1	9	18	4	4	2	3	9	5

Figure D-24a: Winter Demand Response Annual Costs (dollars in thousands)

	DR Winter Bundles ($'000)															
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
2022	$219	$6	$141	$9	$23	$125	$0	$2	$85	$65	$74	$76	$131	$94	$300	$150
2023	$75	$2	$1,016	$4	$3,379	$103	$127	$4	$155	$65	$19	$95	$74	$49	$336	$88
2024	$77	$2	$1,273	$12	$3,504	$261	$132	$10	$185	$78	$39	$119	$77	$51	$454	$183
2025	$515	$9	$2,641	$26	$6,715	$706	$252	$27	$382	$160	$81	$245	$111	$70	$613	$285
2026	$539	$9	$3,210	$47	$6,758	$1,198	$254	$45	$448	$188	$125	$297	$115	$73	$804	$396
2027	$1,032	$16	$3,816	$78	$6,648	$1,817	$250	$68	$517	$217	$173	$353	$119	$75	$1,041	$514
2028	$1,080	$17	$4,460	$95	$6,372	$2,576	$239	$97	$590	$248	$223	$414	$123	$78	$789	$534
2029	$1,129	$18	$2,621	$117	$2,027	$2,393	$76	$90	$287	$121	$231	$245	$55	$39	$864	$555
2030	$1,181	$19	$2,715	$139	$1,863	$2,737	$70	$103	$297	$126	$239	$257	$57	$40	$972	$576
2031	$150	$3	$2,813	$159	$1,684	$3,102	$63	$117	$308	$130	$249	$271	$58	$41	$1,053	$600
2032	$154	$4	$2,913	$176	$1,490	$3,489	$56	$131	$318	$135	$258	$272	$60	$42	$1,137	$624
2033	$157	$4	$3,015	$190	$1,279	$3,900	$48	$147	$329	$139	$265	$278	$61	$43	$1,225	$648
2034	$161	$4	$3,122	$201	$1,050	$4,334	$39	$163	$340	$144	$276	$298	$63	$44	$1,319	$673
2035	$165	$4	$3,231	$210	$804	$4,794	$30	$180	$351	$149	$288	$315	$64	$46	$1,420	$701
2036	$168	$4	$3,343	$218	$735	$4,684	$28	$176	$363	$154	$298	$319	$66	$47	$1,529	$730
2037	$171	$4	$3,457	$226	$1,252	$4,648	$47	$175	$375	$159	$309	$329	$67	$48	$1,645	$760
2038	$175	$4	$3,575	$234	$1,294	$4,809	$49	$181	$388	$164	$320	$343	$69	$49	$1,767	$790
2039	$179	$4	$3,697	$243	$1,337	$4,974	$50	$187	$401	$169	$333	$359	$71	$50	$1,894	$822
2040	$183	$4	$3,823	$251	$1,382	$5,145	$52	$193	$414	$175	$345	$370	$72	$52	$2,065	$854
2041	$187	$4	$3,952	$260	$1,428	$5,321	$54	$200	$428	$181	$358	$386	$74	$53	$2,201	$889
2042	$191	$4	$4,086	$269	$1,476	$5,502	$55	$207	$442	$187	$372	$400	$76	$54	$2,337	$924
2043	$195	$5	$4,223	$279	$1,525	$5,689	$57	$214	$456	$193	$386	$416	$78	$55	$2,473	$959
2044	$200	$5	$4,364	$289	$1,575	$5,881	$59	$221	$471	$199	$401	$432	$80	$57	$2,606	$994
2045	$204	$5	$4,510	$299	$1,628	$6,079	$61	$228	$487	$206	$417	$451	$82	$58	$2,737	$1,032

Figure D-24b: Summer Demand Response Annual Costs (dollars in thousands)

	DR Summer Bundles ($'000)															
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
2022	$220	$5	$65	$85	$23	$125	$0	$2	$48	$102	$74	$76	$81	$144	$300	$150
2023	$75	$2	$984	$37	$3,379	$103	$127	$4	$347	$173	$24	$122	$57	$88	$336	$54
2024	$77	$2	$1,233	$117	$3,504	$261	$132	$10	$414	$207	$50	$153	$59	$91	$454	$111
2025	$516	$8	$2,557	$251	$6,715	$706	$252	$27	$857	$428	$104	$316	$93	$136	$613	$174
2026	$539	$8	$3,108	$456	$6,758	$1,198	$254	$45	$1,003	$501	$161	$382	$96	$141	$804	$241
2027	$1,033	$16	$3,695	$756	$6,648	$1,817	$250	$68	$1,159	$579	$222	$455	$100	$146	$1,041	$314
2028	$1,081	$16	$4,319	$912	$6,372	$2,576	$239	$97	$1,323	$662	$288	$533	$104	$151	$789	$326
2029	$1,130	$17	$2,537	$1,129	$2,027	$2,393	$76	$90	$644	$324	$297	$315	$36	$62	$864	$338
2030	$1,181	$18	$2,629	$1,342	$1,863	$2,737	$70	$103	$666	$335	$309	$332	$36	$63	$972	$352
2031	$151	$3	$2,723	$1,537	$1,684	$3,102	$63	$117	$690	$347	$321	$349	$37	$65	$1,053	$366
2032	$154	$3	$2,820	$1,702	$1,490	$3,489	$56	$131	$713	$359	$332	$351	$38	$66	$1,137	$381
2033	$158	$3	$2,920	$1,835	$1,279	$3,900	$48	$147	$737	$371	$342	$358	$39	$68	$1,225	$395
2034	$162	$3	$3,023	$1,940	$1,050	$4,334	$39	$163	$762	$383	$355	$384	$40	$70	$1,319	$411
2035	$165	$3	$3,129	$2,027	$804	$4,794	$30	$180	$788	$396	$371	$406	$41	$72	$1,420	$428
2036	$169	$3	$3,237	$2,106	$735	$4,684	$28	$176	$814	$410	$384	$412	$42	$73	$1,529	$445
2037	$172	$3	$3,348	$2,183	$1,252	$4,648	$47	$175	$841	$423	$398	$425	$43	$75	$1,645	$464
2038	$176	$3	$3,462	$2,262	$1,294	$4,809	$49	$181	$869	$437	$413	$443	$44	$77	$1,767	$482
2039	$179	$3	$3,580	$2,344	$1,337	$4,974	$50	$187	$898	$452	$429	$463	$45	$79	$1,894	$501
2040	$183	$3	$3,701	$2,428	$1,382	$5,145	$52	$193	$928	$467	$445	$477	$47	$81	$2,065	$521
2041	$188	$3	$3,827	$2,515	$1,428	$5,321	$54	$200	$959	$483	$462	$498	$48	$83	$2,201	$542
2042	$192	$4	$3,956	$2,605	$1,476	$5,502	$55	$207	$991	$498	$479	$516	$49	$85	$2,337	$563
2043	$196	$4	$4,089	$2,697	$1,525	$5,689	$57	$214	$1,023	$515	$498	$536	$50	$87	$2,473	$585
2044	$200	$4	$4,226	$2,792	$1,575	$5,881	$59	$221	$1,057	$532	$517	$557	$51	$89	$2,606	$607
2045	$205	$4	$4,367	$2,890	$1,628	$6,079	$61	$228	$1,091	$549	$537	$582	$53	$91	$2,737	$629

Supply-side Renewable Resource Costs and Technologies

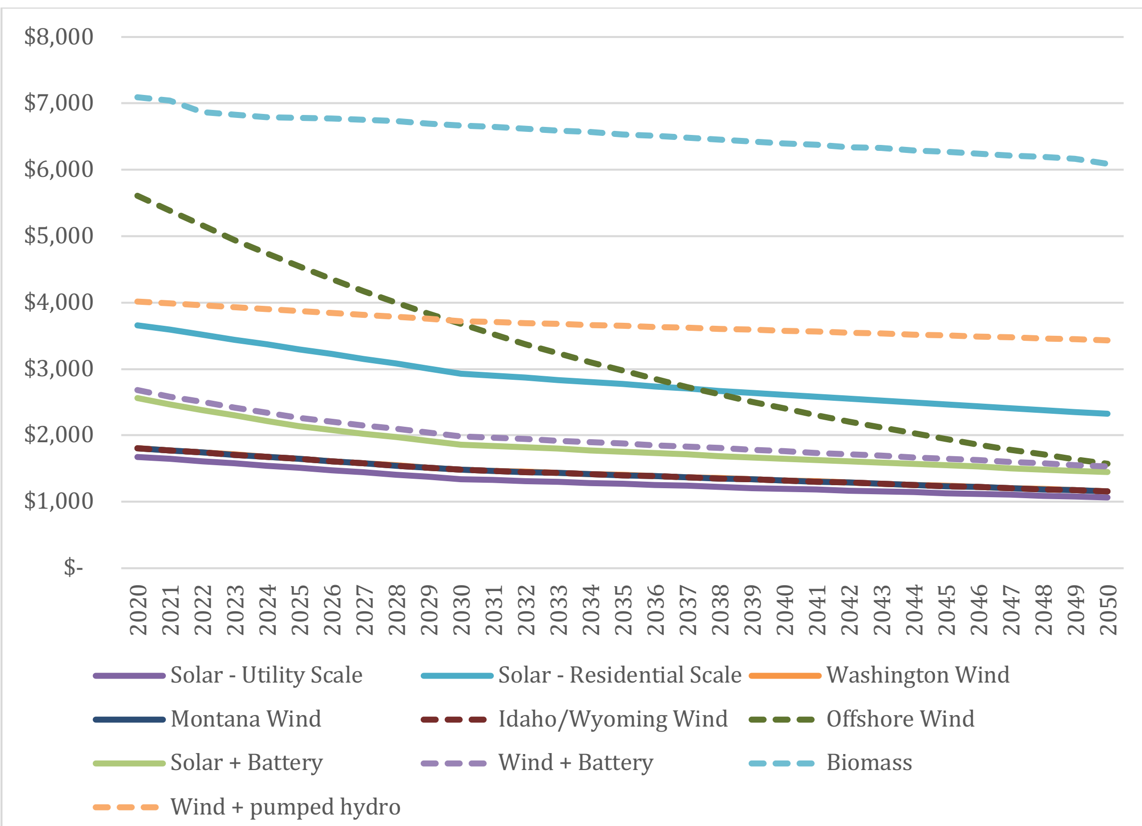
PSE modeled the following supply-side renewable resources in the 2021 IRP:

- biomass
- solar
- wind
- energy storage
- hybrid resources (renewable plus energy storage)

CAPITAL COST CURVE. Capital costs assumptions start in current the current year, but for future years, the cost curve from the NREL Annual Technology Baseline (ATB) 2019 was applied to the current costs.

Figure D-25 below shows the capital cost curves for the renewable resources modeled in the 2021 IRP.

Figure D-25: Capital Cost Curve for Renewable Resources



Biomass Characteristics

Biomass in this context refers to the burning of woody biomass in boilers. Most existing biomass in the Northwest is tied to steam hosts (also known as “cogeneration” or “combined heat and power”). It is found mostly in the timber, pulp and paper industries. This dynamic has limited the amount of power available to date. The typical plant size observed is 10 MW to 50 MW. One major advantage of biomass plants is that they can operate as a baseload resource, since they do not impose generation variability on the grid, unlike wind and solar. Municipal solid waste, landfill and wastewater treatment plant gas are discussed in the section on waste-to-energy technologies, titled Renewable Resources Not Modeled.

Biomass is modeled in the IRP as a 15 MW, wood-fired facility with a heat rate of 14,599 BTU per kWh. These parameters are intended to reflect a cogeneration facility within proximity to a timber mill.

Commercial Availability: This technology is commercially available. Greenfield development of a new biomass facility requires approximately four years.

Figure D-26: Biomass Generic Resource Assumptions

2020 $	UNITS	BIOMASS
ISO Capacity Primary	MW	15
Capacity Credit	%	0%
Operating Reserves	%	3%
Capacity Factor	%	85%
Capital Cost	$/KW	$7,093
O&M Fixed	$/KW-yr	$207
O&M Variable	$/MWh	$6
Land Area	acres/MW	6 – 8
Degradation	%/year	N/A
Fixed Transmission	$/KW-yr	$22.20
Variable Transmission	$/MWh	$0.00
Loss Factor to PSE	%	1.9%
Heat Rate – Baseload (HHV)	Btu/KWh	14,599
EMISSIONS		
NOx	lbs/MMBtu	0.03
SO2	lbs/MMBtu	0.03
CO2	lbs/MMBtu	213
DEVELOPMENT PARAMETERS		
First Year Available		2024
Economic Life	years	30
Greenfield Dev. & Const. Lead Time	years	3.3

Solar Modeling in the IRP

Solar energy uses electromagnetic radiation from the sun to directly generate electricity with photovoltaic (PV) technology, or to capture the heat energy of the sun for either heating water or for creating steam to drive electric generating turbines. This IRP models two solar PV applications, a utility-scale, single-axis tracking PV technology and a residential-scale fixed-tilt, rooftop or ground-mounted PV technology.

For the 2021 IRP, PSE has evaluated six solar resources: utility-scale solar PV in eastern Washington, western Washington, eastern Wyoming, western Wyoming, Idaho and residential-scale rooftop or ground-mounted PV solar in western Washington.

Specific solar generation profiles, or shapes, were derived for each of these solar resource types using irradiance data queries from the NREL's National Solar Radiation Database (NSRDB).[20] The NSRDB irradiance data was then processed with NREL's System Advisory Model (SAM)[21] to create realistic generation profiles for each location. SAM inputs were varied depending on the specific solar resource modeled:

- All solar resources were modeled with SAM's implementation of the NREL PVWatts v7.
- All solar resources were modeled with the "premium" module type to estimate solar panel efficiencies of 18 to 20 percent.
- All solar resources were modeled with a DC to AC ratio of 1.2.
- All solar resources assumed an inverter efficiency of 96 percent.
- Residential-scale solar resources were modeled as fixed-tilt, rooftop or ground-mounted panels.
- Utility-scale solar resources were modeled as ground-mounted, single-axis tracking panels.

Figure D-27 provides a summary of the solar resources modeled. All capacity factors are provided as AC (alternating current), where the capacity of the inverter is taken as the nameplate of the solar facility. This differs from the DC (direct current) capacity, which measures the capacity based on the capacity of the solar modules installed. The AC capacity is typically higher, because most solar facilities undersize the inverter as defined by the DC to AC ratio; in the case of PSE generic resources, the DC to AC ratio is 1.2.

After all profiles were processed by SAM, 250 representative draws are selected from the complete list based on nearness to the annual average production of all the solar profiles sampled. Finally a single, most-representative draw is selected from the 250 draws using the

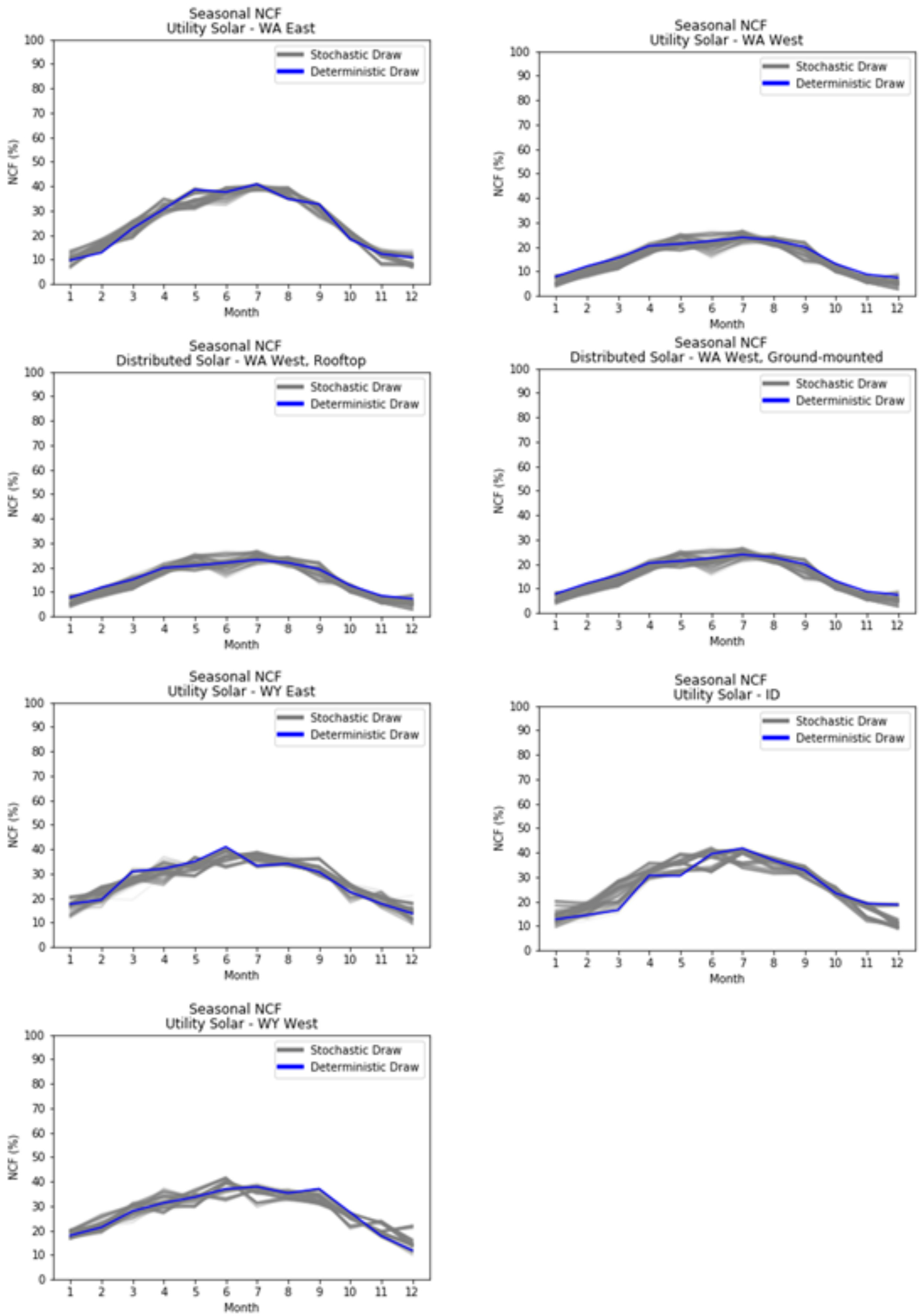
20 / https://nsrdb.nrel.gov/
21 / https://sam.nrel.gov/

same selection process. Figure D-28 provides a summary of the seasonal solar shapes used in the 2021 IRP, the grey lines represent each of the 250 stochastic draws and the blue line represents the draw selected as most-representative.

Figure D-27: Solar Generic Resource Assumptions

2020 $	Units	Utility Solar WA East	Utility Solar WA West	Utility Solar WY West	Utility Solar WY East	Utility Solar ID	Distributed Solar WA West, Rooftop	Distributed Solar WA West, Ground-mounted
ISO Capacity Primary	MW	100	50	400	400	400	300	50
Capacity Credit (2027)	%	4.0%	1.2%	6.0%	6.3%	3.4%	1.6%	1.2%
Operating Reserves	%	3%	3%	3%	3%	3%	3%	3%
Capacity Factor	%	24.2%	16.0%	28.0%	27.3%	26.4%	15.7%	16.0%
Capital Cost	$/KW	$1,675	$1,675	$1,675	$1,675	$1,675	$4,389	$3,568
O&M Fixed	$/KW-yr	$22	$22	$22	$22	$22	$0	$0
O&M Variable	$/MWh	$0	$0	$0	$0	$0	$0	$0
Land Area	acres/MW	5 - 7	5 - 7	5 - 7	5 - 7	5 - 7	N/A	5 - 7
Degradation	%/year	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
Fixed Transmission	$/KW-yr	$30.48	$8.28	$207.80	$227.90	$154.78	$0.00	$0.00
Variable Transmission	$/MWh	$9.53	$9.53	$9.53	$9.53	$9.53	$0.00	$0.00
Loss Factor to PSE	%	1.9%	N/A	4.6%	4.6%	4.6%	N/A	N/A
DEVELOPMENT PARAMETERS								
First Year Available		2024	2024	2026	2026	2026	2024	2024
Economic Life	Years	30	30	30	30	30	30	30
Greenfield Dev. & Const. Lead Time	Years	1.0	1.0	1.0	1.0	1.0	1.0	1.0

Figure D-28: Seasonal Solar Shapes



Solar Technologies

Photovoltaics are semiconductors that generate direct electric currents. The current then typically runs through an inverter to create alternating current, which can be tied into the grid. Most photovoltaic solar cells are made from silicon imprinted with electric contacts; however, other technologies, notably several chemistries of thin-film photovoltaics, have gained substantial market share. Significant ongoing research efforts continue for all photovoltaic technologies, which has helped to increase conversion efficiencies and decrease costs. Photovoltaics are installed in arrays that range from a few watts for sensor or communication applications, up to hundreds of megawatts for utility-scale power generation. PV systems can be installed on a stationary frame at a tilt to best capture the sun (fixed-tilt) or on a frame than can track the sun from sunrise to sunset.

DISTRIBUTED SOLAR uses similar technologies to utility-scale photovoltaic systems, but at a smaller scale. The defining characteristic of distributed solar systems is that the power is generated at, or near, the point where the power will be used. This means that distributed solar systems do not have the same costly transmission requirements of utility-scale systems. Distributed solar may include rooftop or ground-mounted systems (such as parking lot canopies).

CONCENTRATING PHOTOVOLTAICS use lenses to focus the sun's light onto special, high-efficiency photovoltaics, which creates higher amounts of generation for the given photovoltaic cell size. The use of concentrating lenses requires that these technologies be precisely oriented towards the sun, so they typically require active tracking systems.

BIFACIAL PHOTOVOLTAIC modules collect light on both sides of the panel, instead of just on the side facing the sun (as in typical PV installations). Bifacial modules can achieve greater efficiencies per unit of land, reducing the land use requirements. Efficiency gains made by bifacial module are highly dependent on the amount of light reflected by the ground surface, or albedo.

SOLAR THERMAL PLANTS focus the direct irradiance of the sun to generate heat to produce steam, which in turn drives a conventional turbine generator. Two general types are in use or development today, trough-based plants and tower-based plants. Trough plants use horizontally mounted parabolic mirrors or Fresnel mirrors to focus the sun onto a horizontal pipe that carries water or a heat transfer fluid. Tower plants use a field of mirrors that focus sunlight onto a central receiver. A heat transfer fluid is used to collect the heat and transfer it to make steam.

Commercial Availability: Currently, renewable portfolio standards (RPS), falling prices and tax incentives drive most utility-scale solar development in the United States. The Solar Electric Industries Association (SEIA) reports that as of Q3 2020, the U.S. has installed over 85 GW of total solar capacity, with an average annual growth rate of 59 percent over the last ten years.

According to SEIA, solar has ranked first or second in new electric capacity additions in each of the last 7 years. Through Q4 in 2020, 43 percent of all new electric capacity added to the grid came from solar.[22]

With less sunlight than other areas of the country and incentive structures that limit development to smaller systems, photovoltaic development has been relatively slow in the Northwest, and there are no customer or utility-scale concentrating solar thermal installations in Washington state. California continues to be the U.S. leader with nearly 28,000 MW of combined residential, non-residential and utility-scale solar installations as of Q3 2020. While PV installations make up the majority of the installed capacity, the total also includes thermal solar systems, which have been operating successfully in California since the 1980s.[23]

Cost and Performance Assumptions: Since PSE built the Wild Horse Solar Demonstration Project in 2007, installed costs for PV solar systems have declined considerably. SEIA reports that the installed cost of solar has dropped more than 70 percent since 2010, and prices as of Q2 2020 are at or near their lowest historical level across all market segments despite tariffs on modules, inverters, aluminum and steel. According to SEIA's U.S. Solar Market Insight report, by Q3 2020 costs for utility fixed-tilt and tracking projects averaged \$0.80 and \$0.94 per $Watt_{dc}$, respectively; costs for residential systems had reached approximately \$2.84 per $Watt_{dc}$; and costs for commercial systems had reached \$1.37 per $Watt_{dc}$.[24]

Wind Modeling in the IRP

Wind energy is the primary renewable resource for meeting RPS and CETA requirements in our region due to wind's technical maturity, reasonable life cycle cost, acceptance in various regulatory jurisdictions and large "utility" scale compared to other technologies. However, it also poses challenges. Because of its variability, wind's daily and hourly power generation shapes don't necessarily correlate with customer demand; therefore, more flexible thermal and hydroelectric resources must be standing by to fill the gaps. This variability also makes wind power challenging to integrate into transmission systems. Finally, because wind projects are often located in remote areas, they frequently require long-haul transmission on a system that is already congested.

ONSHORE AND OFFSHORE WIND. For this IRP, wind was modeled in the following locations: eastern Washington, central and eastern Montana, western and eastern Wyoming, eastern Idaho and Washington offshore. Figure D-29 summarizes the assumptions for generic wind resources.

22 / Solar Electric Industries Association (SEIA)/Wood Mackenzie Power & Renewables U.S, Solar Market Insight Report, Q4 2020: https://www.seia.org/research-resources/solar-market-insight-report-2020-q4
23 / Solar Electric Industries Association (SEIA), Solar Spotlight – California for Q3 2018, December 2018: https://www.seia.org/sites/default/files/2018-12/Federal_2018Q3_California_1.pdf
24 / Solar Electric Industries Association (SEIA), Solar Market Insight Report, Q4 2020: https://www.seia.org/research-resources/solar-market-insight-report-2020-q4

Eastern Washington wind is located in BPA's balancing authority, so this wind requires only one transmission wheel through BPA to PSE. Montana wind, however, is outside BPA's balancing authority and will require four transmission wheels plus various system upgrades to deliver the power to PSE's service territory. Similarly, the Wyoming and Idaho wind sites are well outside PSE's service territory and will require multiple transmission wheels to deliver the power. PSE is investigating potential ownership of transmission on the Boardman to Hemingway[25] and Gateway West[26] transmission projects currently under construction by Idaho Power and Rocky Mountain Power.

PSE is modeling offshore wind located 3 miles off the coast of Grays Harbor County, Wash. Offshore wind would require a marine cable to interconnect all of the turbines and bring the power back to land. Once on land, it would require a transmission wheel through BPA to PSE.

Specific shapes were derived for each generic wind resource. Wind speed at 100 meters above ground level was obtained from the NREL Wind Toolkit database.[27] For each wind resource location, the database was queried to return all wind profiles within a 50 to 75 mile radius of the point of interest. All of these wind speed profiles, typically 1,000 to 2,000 unique profiles, are then processed with a heuristic wind production model. The wind production model performs the following steps:

- A power curve for a modern, 3 MW, 140 meter rotor diameter turbine is adjusted for site specific air density.
- The wind speed data is processed through the power curve to calculate gross power production.
- A heuristic loss estimation model is used to apply loss factors to the gross production value to obtain net production. Losses include:
    - Turbine interaction effects (waking and blockage)
    - Availability (estimated as a stochastic loss)
    - Temperature loss (based on power curve information)
    - Icing losses (estimated using the International Energy Agency [IEA] Icing Class[28] and applied as a stochastic loss)
    - Degradation, performance and other losses

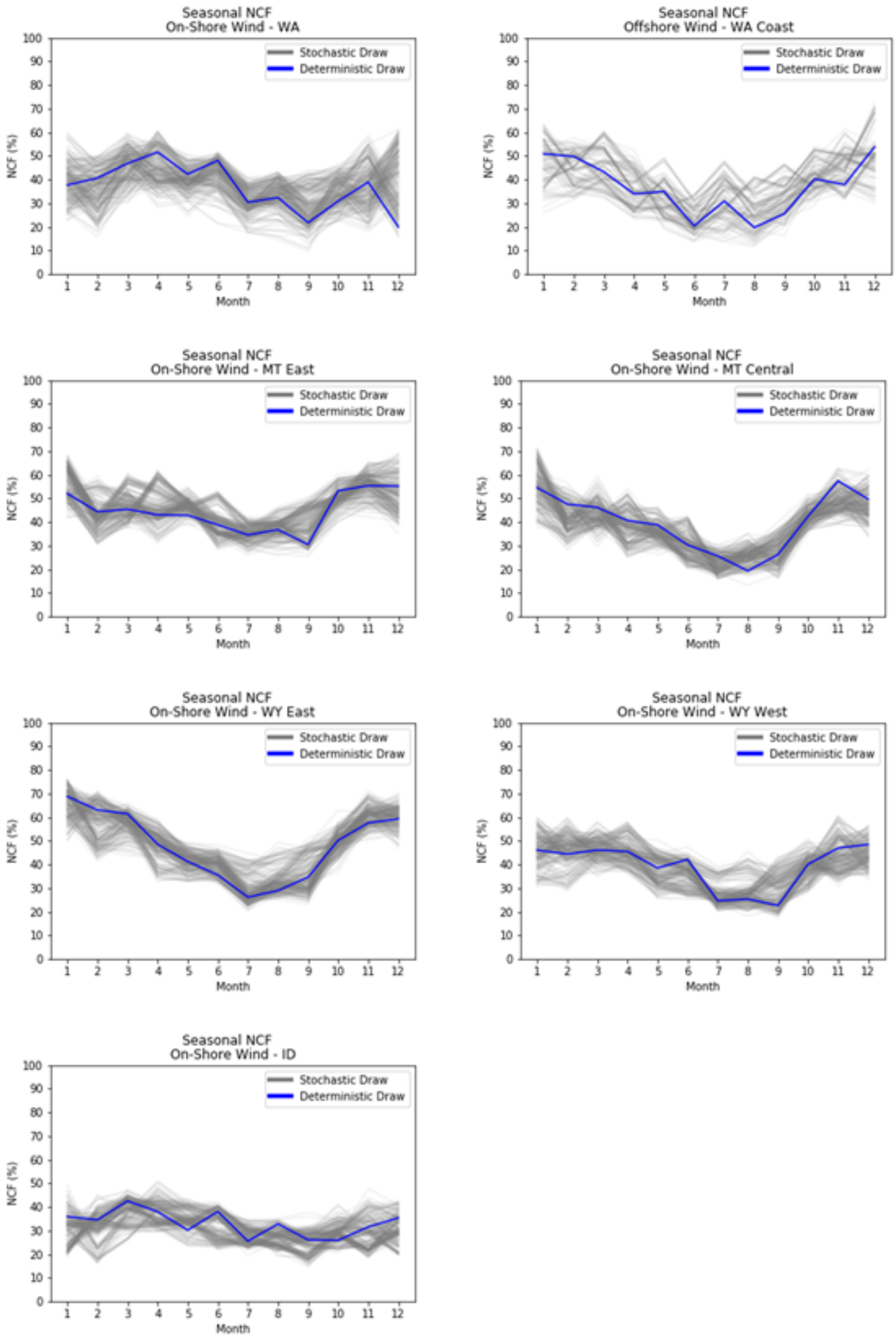
25 / https://www.boardmantohemingway.com/
26 / http://www.gatewaywestproject.com/
27 / https://www.nrel.gov/grid/wind-toolkit.html
28 / http://virtual.vtt.fi/virtual/wiceatla/

After all profiles were processed by the wind production model, 250 representative draws are selected from the complete list. Representative draws are selected based on a least-squares regression to the seasonal average production of all the wind profiles sampled. Finally a single, most-representative draw is selected from the 250 draws using the same selection process. Figure D-30 provides a summary of the seasonal wind shapes used in the 2021 IRP; the grey lines represent each of the 250 stochastic draws and the blue line represents the draw selected as most-representative.

Figure D-29: Wind Generic Resource Assumptions

2020 $	Units	On-Shore Wind MT East	On-Shore Wind MT Central	On-Shore Wind SE Wash.	Off-shore Wind WA Coast	On-Shore Wind WY West	On-Shore Wind WY East	On-Shore Wind ID
ISO Capacity Primary	MW	200	200	100	100	400	400	400
Capacity Credit (2027)	%	21.8%	30.1%	17.8%	48.4%	27.6%	40.0%	24.2%
Operating Reserves	%	3%	3%	3%	3%	3%	3%	3%
Capacity Factor	%	44.3%	39.8%	36.7%	34.8%	39.2%	47.9%	33.0%
Capital Cost	$/KW	$1,806	$1,806	$1,806	$5,609	$1,806	$1,806	$1,806
O&M Fixed	$/KW-yr	$41	$41	$41	$110	$41	$41	$41
O&M Variable	$/MWh	$0	$0	$0	$0	$0	$110	$0
Land Area	acres/MW	48.2	48.2	48.2	N/A	48.2	48.2	48.2
Degradation	%/year	0%	0%	0%	0%	0%	0%	0%
Fixed Transmission	$/KW-yr	$49.65	$49.65	$33.36	$33.36	$210.68	$230.78	$157.66
Variable Transmission	$/MWh	$9.53	$9.53	$9.53	$9.53	$9.53	$9.53	$9.53
Loss Factor to PSE	%	4.6%	4.6%	1.9%	1.9%	4.6%	4.6%	4.6%
DEVELOPMENT PARAMETERS								
First Year Available		2024	2024	2024	2030	2026	2026	2026
Economic Life	years	30	30	30	30	30	30	30
Greenfield Dev. & Const. Lead Time	years	2.0	2.0	2.0	3.2	2.0	2.0	2.0

Figure D-30: Seasonal Wind Shapes



Land-based Wind Technology

Land-based wind turbine generator technology is mature and the dominant form of new renewable energy generation in the Pacific Northwest. While the basic concept of a wind turbine has remained generally constant over the last several decades, the technology continues to evolve, yielding higher towers, wider rotor diameters, greater nameplate capacity and increased wind capture (efficiency). Commercially available turbines are in the 2.0 to 4.0 MW range with hub heights of 80 to 130[29] meters and blade diameters up to160 meters. These changes have come about largely because development of premium high-wind sites has pushed new development into less-energetic wind sites. The current generation of turbines is pushing the physical limits of existing transportation infrastructure. In addition, if nameplate capacity and turbine size continue to increase, the industry must explore creative solutions for ever taller towers, such as concrete tower sections poured or stacked on site and segmented blades for final assembly on site.

Commercial Availability: Declining and expiring tax incentives will likely drive demand in the short term. Greenfield development of a new wind facility requires approximately two to three years and consists of the following activities at a minimum: one to two years for development, permitting and major equipment lead time, and one year for construction.

Cost and Performance Assumptions: The cost for installing a wind turbine includes the turbine, foundation, roads and electrical infrastructure. Installed cost for a typical facility in the Northwest region is approximately $1,319 per kW. The levelized cost of energy for wind power is a function of the installed cost and the performance of the equipment at a specific site, as measured by the capacity factor. The all-in levelized cost of energy ranges from $28.79 to $55.32 per MWh (in 2019 U.S. dollars), which is very dependent on the capacity factor of wind at the location.[30]

Offshore Wind Technology

Offshore winds tend to blow harder and more uniformly than on land. The potential energy produced from wind is directly proportional to the cube of the wind speed. As a result, increased wind speeds of only a few miles per hour can produce a significantly larger amount of electricity. For instance, a turbine at a site with an average wind speed of 16 mph would produce 50 percent more electricity than at a site with the same turbine and average wind speeds of 14 mph.

Wind turbine generators used in offshore environments include durability modifications to prevent corrosion and operate reliably in the harsh marine environment. Their foundations must be

29 / One hundred meters is equivalent to 328 feet which is equivalent to a 30-story building.
30 / U.S. Energy Information Administration (EIA), Annual Energy Outlook 2020, January 2021: https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf. Levelized cost of energy assumes tax credits available for plants entering service in 2022.

designed to withstand storm waves, hurricane-force winds and even ice floes. The engineering and design of offshore wind facilities depends on site-specific conditions, particularly water depth, geology of the seabed, and expected wind and wave loading. Foundations for offshore wind fall into two major categories, fixed and floating, with a variety styles for each category. The fixed foundation is a proven technology that is used throughout Europe. Monopiles are the preferred foundation type, which are steel piles driven into the seabed to support the tower and shell. Fixed foundations can be installed to a depth of 60 meters.

Roughly 90 percent of the offshore U.S. wind energy resource occurs in waters too deep for current fixed foundation technology, particularly on the West Coast. The wind industry is developing new technologies, such as floating wind turbines, that will allow wind construction in the harsher conditions associated with deeper waters.

All power generated by offshore wind turbines must be transmitted to shore and connected to the power grid. Each turbine is connected to an electric service platform (ESP) by a power cable. High voltage cables, typically buried beneath the sea bed, transmit the power collected from wind turbines from the ESP to an onshore substation where the power is integrated into the grid.

Cost and Performance Assumptions: Offshore wind installations have higher capital and operational costs than land-based installations per unit of generating capacity, largely because of turbine upgrades required for operation at sea and increased costs related to turbine foundations, balance of system infrastructure, interconnection and installation, and the difficulty of maintenance access. In addition, one-time costs are associated with the development of infrastructure to support offshore construction, such as vessels for foundation erection and turbine installation and related port facilities.

The United States currently has one operational offshore wind project – the 30 MW Block Island Wind Farm off the coast of Rhode Island which began operation in December 2016. The American Wind Energy Association (AWEA) notes that the two-turbine 12 MW Coastal Virginia Offshore Wind pilot project completed construction in June of 2020 and will start commercial operation later in the year. As a result, reliable capital cost estimates for large-scale U.S. installations are not available. Offshore wind would benefit from a continuation of federal and state government mandates, renewable portfolio standards, subsidies and tax incentives to help innovate and solidify the market. According to AWEA, project developers currently expect 14 offshore wind projects totaling 9,112 MW to be operational by 2026. As the market develops, costs should decrease as experience is gained. Based on the current design trajectory of wind turbine development, bigger units will be able to capture more wind and achieve greater economies of scale in the years ahead.[31]

Commercial Availability: In Europe, offshore wind is a proven technology in shallow coastal waters. Some 14.5 GW have been installed since 1991 with a total installed capacity of 22.1 GW as of 2019, and costs continue to stabilize. The U.S. is just beginning the process of developing offshore wind; however, thousands of megawatts of future development are currently in the planning stages, mostly in the Northeast and Mid-Atlantic regions. Projects are also being considered along the Great Lakes, the Gulf of Mexico and the Pacific Coast. The floating platforms required for deep water offshore wind are yet not commercially mature.

Hybrid Resources

Hybrid resources combine two or more resources at one location to take advantage of synergies created through co-location of the resources. Hybrid resources may combine two generating resources such as solar and wind, or one generating and one storage resource such as solar and a battery energy storage system. Benefits of hybrid resources include reduced land use needs, shared interconnection and transmission costs, improved frequency regulation, backup power potential and operational balancing potential, among others. From 2017 to 2020, the number of installed hybrid systems in the U.S. has more than doubled from less than 30 to 80 facilities.[32]

PSE is evaluating three hybrid systems, each of which pairs a generating resource with a storage resource. These hybrid resources include Washington wind plus 2-hour Lithium-ion battery storage, Washington utility solar plus 2-hour Lithium-ion battery storage, and eastern Montana wind plus pumped hydroelectricity storage. PSE configured the hybrid resources in the model so the storage resource can only charge using the energy from the renewable resource to which it is connected. This is different than co-located resources, which allow the storage resource to be independent of the renewable resource; this is an important distinction for federal tax incentive programs such the Investment Tax Credit (ITC).

31 / https://www.energy.gov/eere/wind/offshore-wind-research-and-development
32 / https://www.eia.gov/todayinenergy/detail.php?id=43775

Figure D-31: Hybrid Generic Resource Assumptions

2020 $	UNITS	MT Wind + Pumped Hydro	Wind + Battery	Solar + Battery
ISO Capacity Primary	MW	300	125	125
Capacity Credit (2027)	%	54.3%	23.6%	14.4%
Operating Reserves	%	3%	3%	3%
Capacity Factor	%	44.3%	36.7%	24.2%
Capital Cost	$/KW	$4,016	$2,680	$2,563
O&M Fixed	$/KW-yr	$57	$64	$46
O&M Variable	$/MWh	$0	$0	$0
Land Area	acres/MW	48.2	48.2	5 - 7
Degradation	%/year	0.0%	0.5%	0.5%
Fixed Transmission	$/KW-yr	$49.65	$33.36	$30.48
Variable Transmission	$/MWh	$9.53	$9.53	$9.53
Loss Factor to PSE	%	4.6%	1.9%	1.9%
First Year Available		2028	2024	2024
Economic Life	years	30	30	30
Greenfield Dev. & Const. Lead Time	years	5 - 8	2.0	1.0
Operating Range	%	147-500 MW	2.0%	2.0%
R/T Efficiency	%	80.0%	82.0%	82.0%
Discharge at Nominal Power	hours	8.0	2.0	2.0

Renewable Resources Not Modeled

FUEL CELLS. Fuel cells combine fuel and oxygen to create electricity, heat, water and other by-products through a chemical process. Fuel cells have high conversion efficiencies from fuel to electricity compared to many traditional combustion technologies, on the order of 25 to 60 percent. In some cases, conversion rates can be boosted using heat recovery and reuse. Fuel cells operate and are being developed at sizes that range from watts to megawatts. Smaller fuel cells power items like portable electric equipment, and larger ones can be used to power equipment, buildings or provide backup power. Fuel cells differ in the membrane materials used to separate fuels, the electrode and electrolyte materials used, operating temperatures and scale (size). Reducing cost and improving durability are the two most significant challenges to fuel cell commercialization. To be economical, fuel cell systems must be cost-competitive with, and perform as well as, traditional power technologies over the life of the system.[33]

Provided that feedstocks are kept clean of impurities, fuel cell performance can be very reliable. They are often used as backup power sources for telecommunications and data centers, which require very high reliability. In addition, fuel cells are starting to be used for commercial combined heat and power applications, though mostly in states with significant subsidies or incentives for fuel cell deployment.

Commercial Availability: Fuel cells have been growing in both number and scale, but they do not yet operate at large scale. According to the Department of Energy's report *State of the States: Fuel Cells in America 2017*,[34] there are fuel cell installations in 43 states, and more than 235 MW of large stationary (100 kW to multi-megawatt) fuel cells are currently operating in the U.S. The report further states that California remains the leader with the greatest number of stationary fuel cells. In some states, incentives are driving fuel cell pricing economics to be competitive with retail electric prices, especially where additional value can be captured from waste heat. Currently, Washington State offers no incentives specific to stationary fuel cells. The EIA, estimates fuel cell capital costs to be approximately $6,700 per kW.[35]

GEOTHERMAL. Geothermal generation technologies use the natural heat under the surface of the earth to provide energy to drive turbine generators for electric power production. Geothermal energy production falls into four major types.

Dry Steam Plants use hydrothermal steam from the earth to power turbines directly. This was the first type of geothermal power generation technology developed.[36]

33 / U.S. Department of Energy, Energy Efficiency and Renewable Energy, Fuel Cell Technologies Program.
34 / U.S. Department of Energy's report, "State of the States: Fuel Cells in America 2017," dated January 2018, https://www.energy.gov/sites/prod/files/2018/06/f53/fcto_state_of_states_2017_0.pdf
35 / U.S. Energy Information Agency Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies, February 2020
36 / http://energy.gov/eere/geothermal/electricity-generation

Flash Steam Plants operate similarly to dry steam plants, but they use low-pressure tanks to vaporize hydrothermal liquids into steam. Like dry steam plants, this technology is best suited to high-temperature geothermal sources (greater than 182 degrees Celsius).[37]

Binary-cycle Power Plants can use lower temperature hydrothermal fluids to transfer energy through a heat exchanger to a fluid with a lower boiling point. This system is completely closed-loop, no steam emissions from the hydrothermal fluids are released at all. The majority of new geothermal installations are likely to be binary-cycle systems due to the limited emissions and the greater number of potential sites with lower temperatures.[38]

Enhanced Geothermal or "hot dry rock" technologies involve drilling deep wells into hot dry or nearly dry rock formations and injecting water to develop the hydrothermal working fluid. The heated water is then extracted and used for generation.[39]

Geothermal plants typically run with high uptime, often exceeding 85 percent. However, plants sometimes do not reach their full output capacity due to lower than anticipated production from the geothermal resource.

Commercial Availability: In 2019, there were geothermal power plants in seven states, which produced about 16 GWh, equal to 0.4% of total U.S. utility-scale electricity generation.[40] As of November 2019, 2.5 GW of geothermal generating capacity was online in the United States.[41] Operating geothermal plants in the Northwest include the 28.5 MW Neal Hot Springs plant and the 15.8 MW Raft River plant in Idaho.

The EIA estimates capital costs for geothermal resources to be approximately $2,521/MW.[42] Because geothermal cost and performance characteristics are specific for each site, this represents the least expensive plant that could be built in the Northwest Power Pool region, where most of the proposed sites are located. Overall, site-specific factors including resource size, depth and temperature can significantly affect costs.

37 / Ibid
38 / Ibid
39 / http://energy.gov/sites/prod/files/2014/02/f7/egs_factsheet.pdf
40 U.S. Energy Information Administration, https://www.eia.gov/energyexplained/geothermal/use-of-geothermal-energy.php
41 / U.S. Energy Information Administration, https://www.eia.gov/todayinenergy/detail.php?id=42036
42 / U.S. Energy Information Administration, Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies, February 2020

WASTE-TO-ENERGY TECHNOLOGIES. Converting wastes to energy is a means of capturing the inherent energy locked into wastes. Generally, these plants take one of the following forms.

Waste Combustion Facilities: These facilities combust waste in a boiler and use the heat to generate steam to power a turbine that generates electricity. This is a well-established technology, with 86 plants operating in the United States, representing 2,720 MW in generating capacity. According to the U.S. EPA's web site, no new facilities have opened since 1995, although some existing facilities have expanded their capacity to convert more waste into electricity.[43]

Waste Thermal Processing Facilities: This includes gasification, pyrolysis and reverse polymerization. These facilities add heat energy to waste and control the oxygen available to break down the waste into components without combusting it. Typically, a syngas is generated, which can be combusted for heat or to produce electricity. A number of pilot facilities once operated in the United States, but only a few remain today.

Landfill Gas and Municipal Wastewater Treatment Facilities: Most landfills in the United States collect methane from the decomposition of wastes in the landfill. Many larger municipal wastewater plants also operate anaerobic systems to produce gas from their organic solids. Both of these processes produce a low-quality gas with approximately half the methane content of natural gas. This low-quality gas can be collected and scrubbed to remove impurities or improve the heat quality of the gas. The gas can then be used to fuel a boiler for heat recovery, or a turbine or reciprocating engine to generate electricity. According to the U.S. EPA's web site, as of August 2020, there are 565 operational landfill gas energy projects in the United States.[44]

43 / U.S. Environmental Protection Agency website. Retrieved from https://www.epa.gov/smm/energy-recovery-combustion-municipal-solid-waste-msw#01, January 2019.
44 / U.S. Environmental Protection Agency website. Retrieved from https://www.epa.gov/lmop/basic-information-about-landfill-gas, August 2020.

Commercial Availability: Washington's RPS initially included landfill gas as a qualifying renewable energy resource, but excluded municipal solid waste. The passage of Washington State Senate bill ESSB 5575 later expanded the definitions of wastes and biomass to allow some new wastes, such as food and yard wastes, to qualify as renewable energy sources.

Currently, several waste-to-energy facilities are operating in or near PSE's electric service area. Three waste facilities – the H.W. Hill Landfill Gas Project, the Spokane Waste-to-Energy Plant and the Emerald City facility – use landfill gas for electric generation in Washington state; combined, they produce up to 67 MW of electrical output. The H.W. Hill facility in Klickitat County is fed from the Roosevelt Regional Landfill and capable of producing a maximum capacity of 36.5 MW.[45] The Spokane Waste-to-Energy Plant processes up to 800 tons per day of municipal solid waste from Spokane County and is capable of producing up to 22 MW of electric capacity.[46] Emerald City uses landfill gas produced at the LRI Landfill in Pierce County to generate up to 4.8 MW of electricity. The facility became commercially operational in December 2013.[47] PSE purchases the electricity produced by the facility through a power purchase agreement under a Schedule 91 contract, which is discussed above.

The largest landfill in PSE's service territory, the Cedar Hills landfill, currently purifies its gas to meet pipeline natural gas quality; the gas is sold to PSE rather than using it to generate electricity.

Cost and Performance Assumptions: Relatively few new waste combustion and landfill gas-to-energy facilities have been built since 2010, making it difficult to obtain reliable cost data. The EIA's *Annual Energy Outlook 2018* estimates municipal solid waste-to-energy costs to be approximately $8,742 per kW.

In general, waste-to-energy facilities are highly reliable. They have used proven generation technologies and gained considerable operating experience for more than 30 years. Some variation of output from landfill gas facilities and municipal wastewater plants is expected due to uncontrollable variations in gas production. For waste combustion facilities, output is typically more stable, as the amount of input waste and heat content can be more easily controlled.

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45 / Phase 1 of the H.W. Hill facility consists of five reciprocating engines, which combined produce 10.5 MW. Phase 2, completed in 2011, adds two 10 MW combustion turbines, and a heat recovery steam generator and steam turbine for an additional 6 MW. Source: Klickitat PUD website. Retrieved from http://www.klickitatpud.com/topicalMenu/about/powerResources/hwHillGasProject.aspx, January 2019.
46 / Spokane Waste to Energy website. Retrieved from https://my.spokanecity.org/solidwaste/waste-to-energy/, January 2019.
47 / BioFuels Washington, LLC landfill gas to energy facility (later sold to Emerald City Renewables, LLC and renamed Emerald LFGTE Facility). Retrieved from https://energyneeringsolutions.com/wp-content/uploads/2018/02/ESI_CaseStudy_Emerald.pdf, January 2019.

WAVE AND TIDAL. The natural movement of water can be used to generate energy through the flow of tides or the rise and fall of waves.

Tidal Generation technology uses tidal flow to spin rotors that turn a generator. Two major plant layouts exist: barrages, which use artificial or natural dam structures to accelerate flow through a small area, and in-stream turbines, which are placed in natural channels. The Rance Tidal Power barrage system in France was the world's first large-scale tidal power plant. It became operational in 1966 and has a generating capacity of approximately 240 MW. The Sihwa Lake Tidal Power Station in South Korea is currently the world's largest tidal power facility. The plant was opened in late 2011 and has a generating capacity of approximately 254 MW. The 20 MW Annapolis Royal Generating Station in Nova Scotia, Canada, is the world's next-largest operating tidal generation facility. China, Russia and South Korea have smaller tidal power installations.[48] Also worth noting is the planned 400 MW Mey Gen Tidal Energy Project in Scotland, which if completed, would be the largest tidal generation facility in the world. The project is designed to be constructed in multiple phases with final deployment targeted for 2021. A 6 MW portion of the first phase began operating in April 2018.[49]

Wave Generation technology uses the rise and fall of waves to drive hydraulic systems, which in turn fuel generators. Technologies tested include floating devices such as the Pelamis and bottom-mounted devices such as the Oyster. The largest wave power plant in the world was the 2.25 MW Agucadoura Wave Farm off the coast of Portugal, which opened in 2008.[50] It has since been shut down because of the developer's financial difficulties.

In 2015, a prototype wave energy device developed by Northwest Energy Innovations was successfully launched and installed for grid-connected, open-sea pilot testing at the Navy's Wave Energy Test Site in Kaneohe Bay on the island of Oahu, Hawaii. According to the U.S. Department of Energy's web site, the 20 kW Azura device is the nation's first grid-connected wave energy converter device.[51]

48 / U.S. Energy Information Administration website. Retrieved from https://www.eia.gov/energyexplained/index.php?page=hydropower_tidal, January 2019.
49 / Wikipedia website. Retrieved from https://en.wikipedia.org/wiki/MeyGen, January 2019.
50 / CNN website. Retrieved from http://www.cnn.com/2010/TECH/02/24/wave.power.buoys/index.html, February 2010.
51 / The U.S. Department of Energy website. Retrieved from https://www.energy.gov/eere/articles/innovative-wave-power-device-starts-producing-clean-power-hawaii, July 2015.

Commercial Availability: Since mid-2013, a number of significant wave and tidal projects and programs have slowed, stalled or shut down altogether. In general, wave and tidal resource development in the U.S. continues to face limiting factors such as funding constraints, long and complex permitting process timelines, relatively little experience with siting and the early stage of the technology's development. FERC oversees permitting processes for tidal power projects, but state and local stakeholders can also be involved. After permits are obtained, studies of the site's water resource and aquatic habitat must be made prior to installation of test equipment.

There are three demonstration tidal projects in various stages of development of the United States, located in Roosevelt Island (New York), Western Passage (Maine) and Cobscook Bay (Maine). Currently, there are no operating tidal or wave energy projects on the West Coast. In late 2014, Snohomish PUD abandoned plans to develop a 1 MW tidal energy installation at the Admiralty Inlet.[52] Several years ago, Tacoma Power considered and later abandoned plans to pursue a project in the Tacoma Narrows.

Tidal and wave generation technologies are very early in development, making cost estimates difficult. Most developers have not produced more than one full-scale device, and many have not even reached that point. Few wave and tidal technologies have been in operation for more than a few years and their production volumes are limited, so costs remain high and the durability of the equipment over time is uncertain.

Energy Storage Resource Costs and Technologies

PSE modeled three energy storage alternatives in the 2021 IRP: lithium-ion batteries, flow batteries and pumped hydro energy storage (PHES).

GENERIC ENERGY STORAGE RESOURCE COST ASSUMPTIONS. Figure D-32 summarizes the generic costs assumptions used in the analysis for energy storage resources. All costs are in 2020 dollars.

52 / The Seattle Times website. Retrieved from http://www.seattletimes.com/seattle-news/snohomish-county-pud-drops-tidal-energy-project/, October 2014.

Figure D-32: Generic Energy Storage Assumptions

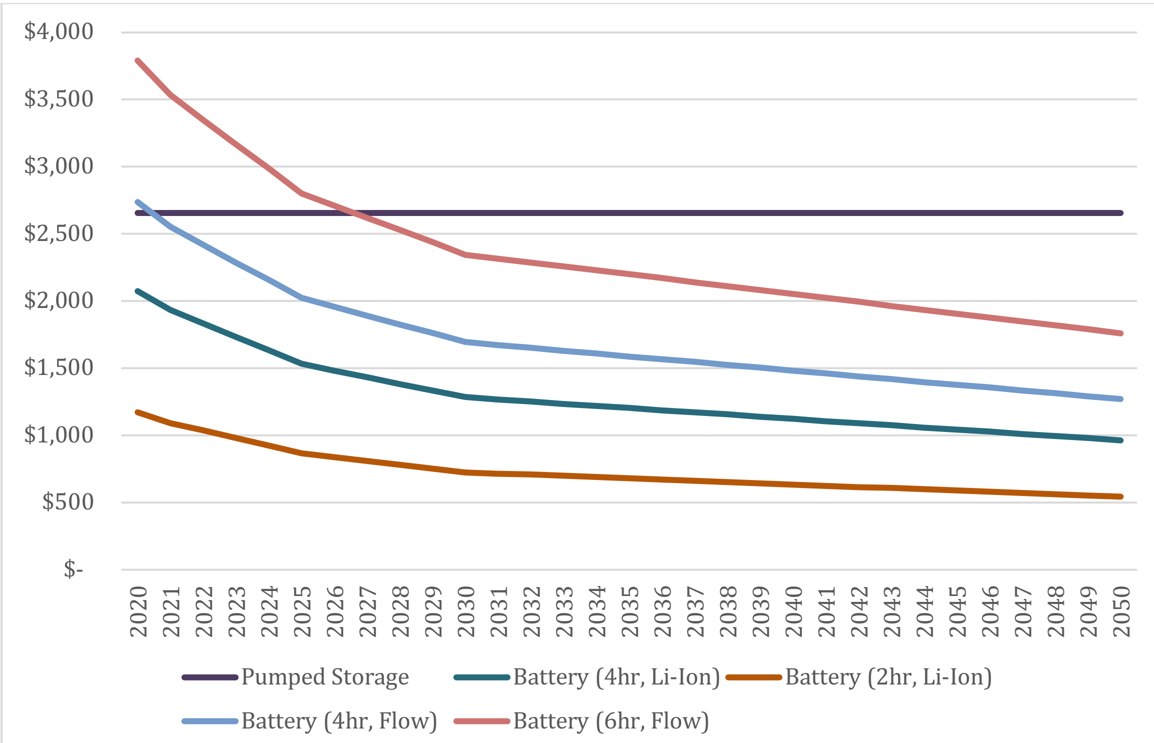
2020 $	UNITS	Pumped Hydroelectric Storage	Battery Energy Storage System (BESS)			
		Closed Loop (8 Hour)	Li-Ion 2-hr (2 Cycles Daily)	Li-Ion 4-hr (2 Cycles Daily)	Flow 4-hr (2 Cycles Daily)	Flow 6-hr (2 Cycles Daily)
Nameplate Capacity	MW	25	25	25	25	25
Capacity Credit (2027)	%	37.2%	12.4%	24.8%	22.2%	29.8%
Operating Reserves	%	3%	3%	3%	3%	3%
Capital Cost	$/KW	$2,656	$1,172	$2,074	$2,738	$3,791
O&M Fixed (c)	$/KW-yr	$16	$23	$32	$22	$38
O&M Variable	$/MWh	$0	$0	$0	$0	$0
Degradation	%/year	(a)	(d)	(d)	(d)	(d)
Operating Range	%	147-500 MW (b)	2.0%	2.0%	2.0%	2.0%
R/T Efficiency	%	80%	82%	87%	73%	73%
Discharge at Nominal Power	Hours	8	2	4	4	6
Maximum Storage	MWh	200	50	100	100	150
Fixed Transmission	$/KW-yr	$22.20	$0.00	$0.00	$0.00	$0.00
Variable Transmission	$/MWh	$0.00	$0.00	$0.00	$0.00	$0.00
First Year Available		2028	2023	2023	2023	2023
Economic Life	years	30	30	30	30	30
Greenfield Dev. & Const. Lead time	years	5 - 8	1	1	1	1

NOTES
Pumped Hydroelectric Storage (PHES) - assumed to represent a slice of a larger project.
a - PHES degradation close to zero
b - The operating range minimum is the average of the minimum at max (111 MW) and min head (183 MW).
c - Fixed O&M costs for Lithium-ion batteries include augmentation by OEM ensuring MW and MWh rating for project life.
d - Battery can discharge up to the indicated percent of nameplate.

CAPITAL COST CURVE. Capital costs assumptions start in the current year, but for future years, the cost curve from the NREL Annual Technology Baseline (ATB) 2019 was applied to the current costs.

Figure D-33 below shows the capital cost curves for the energy storage resources modeled in the 2021 IRP.

Figure D-33: Capital Cost Curve for Energy Storage



Energy Storage Characteristics

Energy storage encompasses a wide range of technologies that are capable of shifting energy usage from one time period to another. These technologies could deliver important benefits to electric utilities and their customers, since the electric system currently operates on "just-in-time" delivery. Generation and load must be perfectly balanced at all times to ensure power quality and reliability. Strategically placed energy storage resources have the potential to increase efficiency and reliability, to balance supply and demand, to provide backup power when primary sources are interrupted and to assist with the integration of intermittent renewable generation. Energy storage technologies are rapidly improving and are capable of benefiting all parts of the system – generation, transmission and distribution – as well as customers. The drawbacks to energy storage are that it operates with a limited duration and requires generation from other sources.

Battery Storage Technologies

Unlike conventional generation resources such as combustion turbines, battery storage resources are modular, scalable and expandable. They can be sized from 20 kW to 1,000 MW and sited at a customer's location or interconnected to the transmission system. It is possible to build the infrastructure for a large storage system and install storage capacity in increments over time as needs grow. This flexibility is a valuable feature of the technology.

Within the battery category, there are many promising chemistries, each with its own performance characteristics, commercial availability and costs. PSE chose to model lithium-ion and flow batteries as the generic battery resources in this IRP because both technologies are commercially available, there are successful projects in operation, and cost estimates and data are available on a spectrum of system configurations and sizes. Other advantages are described below.[53]

LITHIUM-ION BATTERIES have emerged as the leader in utility-scale applications because they offer the best mix of performance specifications for most energy storage applications. Advantages include high energy density, high power, high efficiency, low self-discharge, lack of cell "memory" and fast response time. Challenges include short cycle life, high cost, heat management issues, flammability and narrow operating temperatures. Battery degradation is dependent on the number of cycles and state of the battery's charge. Deep discharge will hasten the degradation of a lithium-ion battery. Lithium-ion batteries can be configured for varying durations (i.e., 0.5 to 6 hours), but the longer the duration, the more expensive the battery. Lithium-ion storage is ideally suited for ancillary applications benefitted by high power (MW), low energy solutions (MWh), and to a lesser extent, for supplying capacity.

53 / In an actual RFP solicitation, PSE would evaluate all proposed technologies based on least-cost and best-fit criteria, including technical and commercial considerations such as warranties, performance guarantees and counterparty credit, etc.

In late 2015, PSE started construction on a 2-megawatt (MW), 4.4 megawatt-hour (MWh) lithium-ion battery system adjacent to the existing substation in the Whatcom County town of Glacier. The project is funded in part by a $3.8 million Smart Grid grant from the Washington State Department of Commerce, in addition to a $7.4 million investment by PSE. The battery was energized in 2016, and in January, 2017, achieved its first successful islanding attempt. Between January, 2018 and June, 2018, Pacific Northwest National Laboratory (PNNL) performed two use test cases. Since then, PSE has continued to test the battery's capabilities under planned outage scenarios – working toward the goal of successfully responding to unplanned outages. As of August, 2019, PSE has successfully powered Glacier's town core through more than six planned outages. The Glacier battery's first successful unplanned response occurred on February 4, 2019, when the battery remotely responded to an outage and provided power for approximately 4 hours until repairs were made to the transmission line.

FLOW BATTERIES are a type of rechargeable battery in which recharge ability is provided by two chemical components dissolved in liquids contained within the system. The two components are separated by a membrane, and ion exchange occurs through the membrane while both liquids circulate in their respective spaces. The ion exchange provides the flow of electric current. Flow batteries can provide the same services as lithium-ion batteries, but they can be used with more flexibility because they do not degrade over time. Flow batteries have limited market penetration at this time, but are an emerging battery storage technology. In 2016, Avista Utilities installed the first large-scale U.S.[54] flow battery storage system in Washington, and in 2017 two additional flow battery facilities were installed by electric utilities in Washington and California. Approximately 70 MW and 250 MWh of flow batteries, almost all in medium- to large-scale projects, have been deployed worldwide.[55]

Commercial Availability: At the end of 2018, the U.S. had 869 MW of large-scale battery energy storage resources in operation. Lithium-ion batteries continued to dominate the energy storage market, representing more than 90 percent of operating large-scale battery storage capacity. In 2018, U.S. utilities also reported 234 MW of existing small-scale storage capacity.[56] Just over 50 percent of this capacity was installed in the commercial sector, 31 percent in the residential sector and 15 percent in the industrial sector, with the remaining 3 percent directly connected to the distribution grid.

54 / Large-scale refers to a facility that is typically grid connected and greater than 1 MW in capacity. Small-scale refers to systems typically connected to a distribution system that are less than 1 MW in power capacity.
55 / IDTechEx Research, Batteries for Stationary Energy Storage 2019-2029
56 / U.S. Energy Information Administration, U.S. Battery Storage Market Trends, July 2020: https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf

Pumped Hydroelectric Storage Technology

Pumped hydroelectric storage ("pumped storage" or "pumped hydro") plants provide the bulk of utility-scale energy storage in the United States. These facilities store energy in the form of water, which is pumped to an upper reservoir from a second reservoir at a lower elevation. During periods of high electricity demand, the stored water is released through turbines to generate power in the same manner as a conventional hydropower station. Load shifting over a number of hours requires a large volume of energy storage capacity, and a storage device like pumped hydro is well suited for this type of application. During periods of low demand (usually nights or weekends when electricity costs less), the upper reservoir is "recharged" by using lower-cost electricity from the grid to pump the water back to the upper reservoir.

Reversible pump-turbine and motor-generator assemblies can act as both pumps and turbines. Pumped storage facilities can be very economical due to peak and off-peak price differentials and because they can provide critical ancillary grid services. Pumped storage projects are traditionally large, at 300 MW or more. Due to environmental impacts, permitting for these projects can take many years. Pumped storage can be designed to provide 6 to 20 hours of storage with 80 percent roundtrip efficiency.

Commercial Availability: According to the Department of Energy's most recent *Hydropower Market Report*, there are 43 plants with a capacity of 21.9 GW, which represent 93 percent of utility-scale electrical energy storage in the U.S. Most of this capacity was installed between 1960 and 1990, and almost 94 percent of these storage facilities are larger than 500 MW. No new pumped storage projects have come online in the United States since 2012.[57] At the end of 2019, there were 67 pumped storage projects with a potential capacity of 52.48 GW in the development pipeline. The median project size in the development pipeline is 480 MW, but projects span a wide range of sizes from large projects greater than 3,000 MW to small closed-loop systems of less than 100 MW.[58]

57 / U.S. Energy Information Agency, Annual Electric Generator Report
58 / https://www.energy.gov/sites/prod/files/2021/01/f82/us-hydropower-market-report-full-2021.pdf

Energy Storage Not Modeled

LIQUID AIR ENERGY STORAGE (LAES). LAES converts energy from a variety of sources, such as natural gas or wind, and stores it as thermal energy. To charge the energy, air is cooled and compressed into a liquid state using electricity (i.e., liquefied air or liquefied nitrogen) and stored in tanks. To dispatch electrical energy back to the grid, the liquid air is heated and pressurized, bringing it back to a gaseous state. The gas is used to turn a turbine to generate electricity.

Potential benefits include the technology's suitability to deliver large-scale power for utility and distributed power applications; its suitability for long-duration energy storage; and its ability to use waste heat and cold from its own processes to enhance its efficiency. Also, LAES systems can be large in scale without requiring a large footprint, giving them greater geographical flexibility.

Commercial Availability: LAES systems combine three existing technologies: industrial gas production, cryogenic liquid storage and expansion of pressurized gasses. While the components are based on proven technology currently used in industrial processes and available from large Original Equipment Manufacturers (OEMs), no commercial LAES systems are currently in operation in the U.S. However, in June 2018, Highview Power Storage, a small U.K. company partnering with GE to develop utility-scale LAES systems, launched the world's first grid-scale LAES plant at a landfill gas site near Manchester. The pilot plant is capable of producing 5 MW/15MWh of storage capacity. According to Highview Power Storage, the technology can be scaled up to hundreds of megawatts to better align with the needs of cities and towns.[59]

HYDROGEN ENERGY STORAGE. Hydrogen energy storage systems use surplus renewable electricity to power a process of electrolysis, in which current is passed through a chemical solution to separate and create hydrogen. This renewable hydrogen is then stored for later conversion back into electricity, as well as for other applications such as fuel for transport. Hydrogen does not degrade over time and can be stored for long periods in large quantities, most notably in underground salt caverns. This pure hydrogen can be used for re-electrification in a fuel cell or combusted in a gas turbine.

59 / Forbes website. Retrieved from https://www.forbes.com/sites/mikescott/2018/06/08/liquid-air-technology-offers-prospect-of-storing-energy-for-the-long-term/#3137f759622f, January, 2019.

Commercial Availability: In 2018, Enbridge Gas Distribution and Hydrogenics opened North America's first multi-megawatt power-to-gas facility using renewably sourced hydrogen, the 2.5 MW Markham Energy Storage Facility in Ontario, Canada. In the United States, SoCalGas has partnered with the National Fuel Cell Research Center to install an electrolyzer powered by the University of California at Irvine on-campus solar electric system, which generates renewable hydrogen to be fed into the campus power plant. SoCalGas has also partnered with NREL to install the nation's first biomethanation reactor system located at their Energy Systems Integration Facility (ESIF) in Golden, Colo. Full-scale hydrogen energy projects are also in development, most notably a 1,000 MW Advanced Clean Energy Storage (ACES) facility in Utah through a partnership of Mitsubishi Hitachi Power Systems and Magnum Development, which owns large salt caverns to store the hydrogen. Xcel Energy is partnering with the NREL to create a 110 kW wind-to-hydrogen project using the site's hydrogen fueling station for storage, to be converted back to electricity and fed to the grid during peak demand hours.[60]

Supply-side Thermal Resource Costs and Technologies

PSE modeled two types of thermal resources in the 2019 IRP, baseload combustion turbine plants and peaking capacity plants.

Generic Combustion Turbine Resource Cost Assumptions

Figure D-34 summarizes the cost assumptions used in the analysis for baseload combustion turbine plants and peaking capacity plants. All costs are in 2020 dollars.

60 / Sources: Fuel Cell & Hydrogen Energy Association, Energy Storage Association, Utility Dive

Figure D-34: Generic Combustion Turbine Resource Assumptions

2020 $	UNITS	FRAME PEAKER 1x0 F-Class Dual Fuel CT (NG)	CCCT 1x1 F-Class CC (NG Only)	RECIP PEAKER 12x0 18 MW RICE (NG Only)
ISO Capacity Primary	MW	225	336	219
Winter Capacity Primary (23º F)	MW	237	348	219
Incremental Capacity DF (23º F)	MW	N/A	19	N/A
Capital Cost + Duct Fire*	$/KW	$947.53	$1,254.53	$1,671.27
O&M Fixed	$/KW-yr	$7.68	$12.87	$6.40
O&M Fixed	$MW-week	$147.63	$247.45	$123.15
O&M Variable	$/MWh	$7.86	$3.32	$7.05
Start-up Costs	$/Start	$6,831.16	N/A	N/A
Operating Reserves	%	3%	3%	3%
Forced Outage Rate	%	2.38%	3.88%	3.30%
Heat Rate – Baseload (HHV)	Btu/KWh	9,904	6,624	8,445
Heat Rate – Turndown (HHV)	Btu/KWh	15,794	7,988	11,288
Heat Rate – DF	Btu/KWh	N/A	8,867	N/A
Minimum Capacity	%	30%	38%	30%
Start Time (hot)	minutes	21	45	5
Start Time (warm)	minutes	21	60	5
Start Time (cold)	minutes	21	150	5
Start-up fuel (hot)	mmBtu	366	839	69
Start-up fuel (warm)	mmBtu	366	1,119	69
mmBtu/MW/Start (warm)		1.544	3.214	0.317
Staru-up fuel (cold)	mmBtu	366	2,797	69
Ramp Rate	MW/min	40	40	16

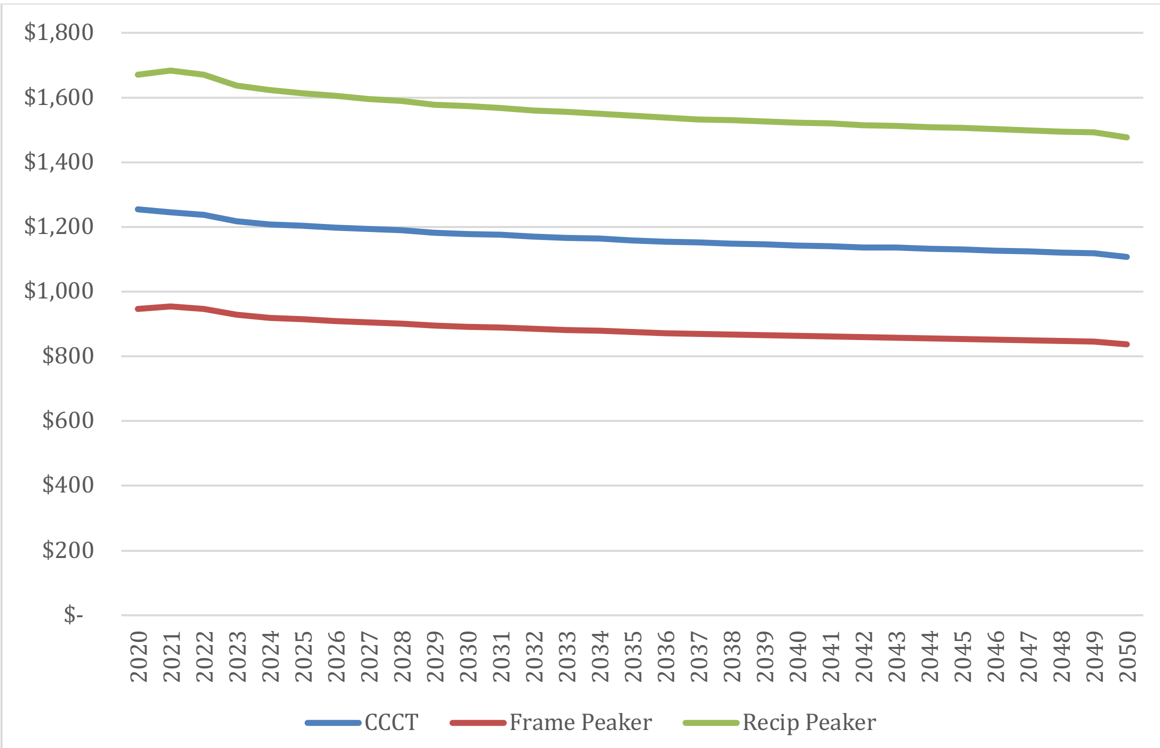
Fixed Gas Transport	$/Dth/Day	$0.00	$0.25	$0.25
Fixed Gas Transport	$/KW-yr	$0.00	$14.67	$18.70
Variable Gas Transport	$/MMBtu	$0.04	$0.06	$0.06
Fixed Transmission	$/KW-yr	$0.00	$0.00	$0.00
Variable Transmission	$/MWh	$0.00	$0.00	$0.00
EMISSIONS				
CO2 - Natural Gas	lbs/MMBtu	118	118	118
NOx - Natural Gas	lbs/MMBtu	0.004	0.008	0.029
DEVELOPMENT PARAMETERS				
First Year Available		2025	2025	2025
Economic Life	years	30	30	30
Greenfield Dev. & Const. Lead Time	years	1.8	2.7	2.3

NOTES
1. For recip peaker, the ramp rate indicated is for a single reciprocating internal combustion engine (RICE) unit; operations and maintenance costs include oil backup.
2. For frame peaker, operations and maintenance costs include oil backup. Variable Operations and Maintenance (VOM) is variable operations only. Major maintenance is included in start-up costs.

CAPITAL COST CURVE. Capital costs assumptions start in current the current year, but for future years, the cost curve from the NREL Annual Technology Baseline (ATB) 2019 was applied to the current costs.

Figure D-35 below shows the capital cost curves for the thermal plants modeled in the 2021 IRP.

Figure D-35: Capital Cost Curve for Thermal Plants



NATURAL GAS TRANSPORTATION COSTS MODELED. Fixed and variable natural gas transportation costs for the combustion turbine plants assume that natural gas is purchased at the Sumas Hub. Natural gas transportation costs for resources without oil backup assume the need for 100 percent firm gas pipeline transportation capacity plus firm storage withdrawal rights equal to 20 percent of the plant's full fuel requirements. This applies to the baseload CCCT and reciprocating engine without oil. The analysis assumes that the gas transportation needs for these resources will be met with 100 percent firm gas transportation on a Northwest Pipeline (NWP) expansion to Sumas plus 100 percent firm gas transportation on the Westcoast Pipeline[61] expansion to Station 2. The plants are dispatched to Sumas prices, so a basis differential gain between Sumas and Station 2 mitigates the gas transportation costs. For frame peaker resources, we assume oil backup with no firm gas transportation.

61 / Westcoast Pipeline is operated by Westcoast Energy, a subsidiary of Enbridge, Inc.

Figure D-36 below shows the natural gas transport assumptions for resources without oil backup.

Figure D-36: Natural Gas Transportation Costs for Western Washington CCCT and Reciprocating Engine Peakers without Oil Backup – 100% Sumas on NWP + 100% Station 2 on Westcoast

PIPELINE/RESOURCE	FIXED DEMAND ($/DTH/DAY)	VARIABLE COMMODITY ($/DTH)	ACA CHARGE ($/DTH)	FUEL USE (%)	UTILITY TAXES (%)
NWP Expansion[1]	0.6900	0.0083	0.0013	1.41%	3.85%
Westcoast Expansion[2]	0.7476	0.0551	-	-	-
Basis Gain[3]	(0.8139)	-	-	2.71%	3.85%
Gas Storage[4]	0.0767	-	-	2.00%	3.85%
Total	***0.7004***	***0.0634***	***0.0013***	***6.12%***	***3.85%***

NOTES
1. Estimated NWP Sumas to PSE Expansion
2. Estimated Westcoast Expansion Fixed Demand
3. Basis gain represents the average of the Station 2 to Sumas price spread, net of fuel losses and variable costs over the 20-year forecast period. Variable Commodity Charge includes B.C. carbon tax and motor fuel tax of $0.0551 per Dth per day and fuel losses are 2.71 percent per Dth. A state utility tax of 3.852% applies to the natural gas price.
4. Storage requirements are based on current storage withdrawal capacity to peak plant demand for the natural gas for power portfolio (approximately 20 percent).

Figure D-37: Natural Gas Transportation Costs for Western Washington Frame Peakers with Oil Backup – No Firm Gas Pipeline

PIPELINE/ RESOURCE	FIXED DEMAND ($/DTH/DAY)	WEIGHTED AVERAGE “VARIABLE” DEMAND ($/DTH)	VARIABLE COMMODITY ($/DTH)	ACA CHARGE ($/DTH)	FUEL USE (%)	UTILITY TAXES (%)
NWP Demand	0.0000	0.0300	0.0083	0.0013	1.41%	3.82%
Total	**0.0000**	**0.0300**	**0.0083**	**0.0013**	**1.41%**	**3.82%**

Combustion Turbine (CT) Characteristics

Combustion turbines still play an important role in the portfolio given their versatility and reliability. PSE is exploring fuel alternatives to natural gas fuel, such as RNG, hydrogen and biodiesel as we move toward CETA goals. For this IRP, PSE analyzed the use of biodiesel. The following characteristics make combustion turbines an important tool.

- **Proximity:** Combustion turbines located within or adjacent to PSE's service area avoid costly transmission investments required for long-distance resources like wind.
- **Timeliness:** Combustion turbines are dispatchable, meaning they can be turned on when needed to meet loads, unlike "intermittent" resources that generate power sporadically such as wind, solar and run-of-the-river hydropower.
- **Versatility:** Combustion turbine generators have varying degrees of ability to ramp up and down quickly in response to variations in load and/or wind generation.

When relying on natural gas fuel, storage and fuel supply are important considerations, so the analysis also includes gas storage for some resources. The baseload and peaking resources modeled in this analysis are described below.

Baseload Combustion Turbine (CT) Technologies

Baseload CT plants – combined-cycle combustion turbines or CCCTs – produce energy at a constant rate over long periods at a lower cost relative to other production facilities available to the system. They are typically used to meet some or all of a region's continuous energy demand.

COMBINED-CYCLE COMBUSTION TURBINES (CCCTs). These baseload plants consist of one or more combustion turbine generators equipped with heat recovery steam generators that capture heat from the combustion turbine (CT) exhaust. This otherwise wasted heat is then used to produce additional electricity via a steam turbine generator. The baseload heat rate for the CCCTs modeled for this IRP is 6,624 BTU per kWh. Many plants also feature "duct firing." Duct firing can produce additional capacity from the steam turbine generator, although with less efficiency than the primary unit. CCCTs have been a popular source of baseload electric power and process steam generation since the 1960s because of their high thermal efficiency and reliability, relatively low initial cost and relatively low air emissions.

In this analysis, natural gas supply is assumed to be firm year-round at projected incremental gas pipeline firm rates. This analysis assumes 20 percent of gas storage is available to the baseload CCCT plants modeled to accommodate mid-day start-ups or shutdowns. The unit is assumed to be connected to the PSE transmission system and as such does not incur any direct transmission cost.

This technology is commercially available. Greenfield development requires approximately three years.

Peaker Technologies

Peakers are quick-starting single-cycle combustion turbines that can ramp up and down rapidly in order to meet spikes in need. They also provide flexibility needed for load following, wind integration and spinning reserves. PSE modeled two types of peakers; each brings particular strengths to the overall portfolio.

FRAME PEAKERS. Frame CT peakers are also known as “industrial” or “heavy-duty” CTs; these are generally larger in capacity and feature frames, bearings and blading of heavier construction. Conventional frame CTs are a mature technology. They can be fueled by natural gas, distillate oil or a combination of fuels (dual fuel). PSE is exploring fuel alternatives to natural gas fuel, such as RNG, hydrogen and biodiesel as we move toward CETA goals. In this IRP, PSE evaluated the use of biodiesel. The turndown capability of the units is 30 percent. The assumed heat rate for frame peakers in this IRP is 9,904 BTU per kWh. They also have slower ramp rates than other peakers, on the order of 40 MW per minute for 237 MW facilities, and some can achieve full load in twenty-one minutes.

Frame CT peakers are commercially available. Greenfield development requires approximately two years.

RECIP PEAKERS (RECIPROCATING INTERNAL COMBUSTION ENGINE - RICE). The reciprocating engine technology evaluated is based on a four-stroke, spark-ignited gas engine which uses a lean burn method to generate power. The lean burn technology uses a relatively higher ratio of oxygen to fuel, which allows the reciprocating engine to generate power more efficiently. Ramp rates are 16 MW per minute for an 18 MW facility. The heat rate is 8,445 BTU per kWh. However, reciprocating engines are constrained by their size. The largest commercially available reciprocating engine for electric power generation produces 18 MW, which is less than the typical frame peaker. Larger-sized generation projects would require a greater number of reciprocating units compared to an equivalent-sized project implementing a frame turbine, reducing economies of scale. A greater number of generating units increases the overall project availability and reduces the impact of a single unit out of service for maintenance. Reciprocating engines are more efficient than simple-cycle combustion turbines, but have a higher capital cost. Their small size allows a better match with peak loads, thus increasing operating flexibility relative to simple-cycle combustion turbine peakers.

This technology is commercially available. Greenfield development requires approximately three years.

Oil Backup: For frame peakers with oil backup, natural gas supply is assumed to be available on an interruptible basis at projected gas pipeline seasonal interruptible rates for much of the year. The oil backup is assumed to provide fuel during peak periods. For units without oil backup, natural gas supply is assumed to be firm year-round at projected incremental gas pipeline firm rates. In either case, the analysis assumes 20 percent of gas storage is available to the peaking gas plants modeled to accommodate mid-day start-ups or shutdowns. The peaker unit is assumed to be connected to the PSE transmission system and as such does not incur any direct transmission cost.

Thermal Resources Not Modeled

As discussed below, other potential thermal resource alternatives are constrained by law, practical obstacles and cost. Long-term coal-fired generation is not a resource alternative because RCW 80.80 precludes utilities in Washington from entering into new long-term agreements for coal. The Clean Energy Transformation Act (CETA) also requires utilities to eliminate coal-fired generation from their state portfolios by 2025. New nuclear generation is neither practical nor feasible.

COAL. Coal fuels a significant portion of the electricity generated in the United States. Most coal-fired electric generating plants combust the coal in a boiler to produce steam that drives a turbine-generator. A small number of plants gasify coal to produce a synthetic gas that fuels a combustion turbine. Of the fuels commonly used to produce electricity, coal produces the most greenhouse gases (GHGs) per MWh of electricity. Technologies for reducing or capturing some of the GHGs produced are currently in the research and development phase.

Commercial Availability: New coal-fired generation is not a resource alternative for PSE, because RCW 80.80 sets a generation performance standard for electric generating plants that prohibits Washington utilities from building plants or entering into long-term electricity purchase contracts from units that emit more than 970 pounds of GHGs per MWh.[62] With currently available technology, coal-fired generating plants produce GHGs (primarily carbon dioxide) at a level two or more times greater than the performance standard, and carbon capture and sequestration technology is not yet effective or affordable enough to significantly reduce those levels. Furthermore, CETA, passed on May 7, 2010, explicitly requires Washington state utilities to eliminate coal-fired electricity generation from their state portfolios by 2025.

There are no new coal-fired power plants under construction or development in the Pacific Northwest.

62 / To support a long-term plan to shut down the only coal-fired generating plant in Washington state, state government has made an exception for transition contracts with the Centralia generating plant through 2025.

NUCLEAR. Capital and operating costs for nuclear power plants are significantly higher than most conventional and renewable technologies such that only a handful of the largest capitalized utilities can realistically consider this option. In addition, nuclear power carries significant technology, credit, permitting, policy and waste disposal risks.

Cost Assumptions: There is little reliable data on recent U.S. nuclear developments from which reasonable and supportable cost estimates can be made. The construction cost and schedule track record for nuclear plants built in the U.S. during the 1980s, 1990s and 2000s has been poor at best. Actual costs have been far higher than projected, construction schedules have been subject to long delays, and interest rate increases have resulted in high financing charges. The Fukushima incident in 2011 also motivated changing technical and regulatory requirements and public controversy that have contributed to project cost increases.

With many other energy options to choose from, the demonstrated high cost, poor completion track record, lack of a comprehensive waste storage/disposal solution and the bankruptcy of a major nuclear supplier all create significant uncertainty, making nuclear energy an unwise and unnecessary risk for PSE at this time.

AERO PEAKERS (Aeroderivative Combustion Turbines). Aeroderivative combustion turbines are a mature technology, however, new aeroderivative features and designs are continually being introduced. They can be fueled by natural gas, oil, RNG, hydrogen, biodiesel or a combination of fuels (dual fuel). A typical heat rate is 8,810 BTU per kWh. Aero units are typically more flexible than their frame counterparts, and many can reduce output to nearly 25 percent. Most can start and achieve full output in less than eight minutes and start multiple times per day without maintenance penalties. Ramp rates are 50 MW per minute for a 227 MW facility. Another key difference between aero and frame units is size. Aero CTs are typically smaller in size, from 5 to 100 MW each. This small scale allows for modularity, but it also tends to reduce economies of scale.

This technology is commercially available. Greenfield development requires approximately three years.

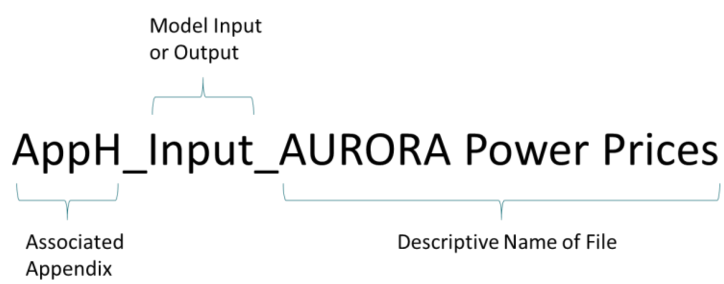
E Conservation Potential Assessment and Demand Response Assessment

The Conservation Potential Assessment and Demand Response Assessment developed by Cadmus Group for the IRP analysis evaluates the type and quantity of conservation measures available from utility programs, codes and standards, and customer-driven programs; demand response; and distributed solar generation.

APPENDIX E FILES

For the 2021 IRP, PSE is providing Microsoft Excel files containing input and output data in separate files instead of data tables directly in the Final IRP report. The direct access to the data provides usable files for stakeholders as opposed to stagnant tables in a PDF format. Technical limitations on how PSE is able to submit files to the WUTC and host files online for stakeholder access has prevented PSE from keeping the files organized in a series of folders. To overcome this, a descriptive naming system has been developed in order to identify different files. Figure E-1 provides an example of how the files will be named in Appendix H, Electric Analysis Inputs and Results. The same format is used for files from Appendix E. Each Excel file also contains a "Read_Me" sheet with specific details related to the data contained in that file.

Figure E-1: The naming scheme of Appendix H and Appendix E files.



Cadmus has provided additional files with the Conservation Potential Assessment of Appendix E. The files contain the underlying data of the conservation and demand response measures. The programs included in the Energy Efficiency file contain breakdowns into Industrial, Commercial, and Residential measures. For the 2021 IRP electric models, the classes are aggregated together and then the combined energy efficiency is used. Figure E-2 provides the file names of these datasets.

Figure E-2: The names of Appendix E files.

File Names	Description
AppE_Input_Energy Efficiency Potential	Contains the underlying data of the conservation bundles included in the 2021 IRP.
AppE_Input_Demand Response Potential	Contains the underlying data of the demand response programs included in the 2021 IRP.

Comprehensive Assessment of Demand-Side Resource Potentials (2022 – 2045):

Conservation Potential Assessment

Demand Response Assessment

Distributed Solar Assessment

December 4, 2020

Prepared for:

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Acronyms and Abbreviations

Acronym	Definition
ACEEE	American Council for an Energy-Efficient Economy
AMI	Advanced Metering Infrastructure
aMW	Average megawatt
ASP	Annualized simple payback
ATB	Annual technology baseline
BYOT	Bring your own thermostat
C&I	Commercial and industrial
CBECS	Commercial Building Energy Consumption Survey
CBSA	Commercial Building Stock Assessment
CEE	Consortium for Energy Efficiency
CHP	Combined Heat and Power
Council	Northwest Power and Conservation Council
CPA	Conservation Potential Assessment
CPP	Critical peak pricing
DEER	California Database of Energy Efficient Resources
DLC	Direct Load Control
DOE	U.S. Department of Energy
DR	Demand response
DSR	Demand-side resources
EERE	Office of Energy Efficiency and Renewable Technology (U.S. Department of Energy)
EIA	U.S. Energy Information Administration
EISA	Energy Independence and Security Act
ERWH	Electric resistance water heater
EUL	Effective useful life
EV	Electric vehicle
EVSE	Electric vehicle service equipment
FTE	Full-time equivalent
GEWH	Grid-enabled water heater
HB	House Bill
HPWH	Heat pump water heater
HVAC	Heating, ventilation, and air conditioning
IFC	International Fire Code
IRP	Integrated resource plan
LCOE	Levelized cost of electricity
LED	Light-emitting diode
LI	Low income
LIDAR	Light detection and ranging
NEEA	Northwest Energy Efficiency Alliance
NPV	Net present value
NREL	National Renewable Energy Laboratory
O&M	Operations and maintenance
PCT	Programmable communicating thermostat
PSE	Puget Sound Energy
PV	Photovoltaic

Acronym	Definition
RBSA	Residential Building Stock Assessment
RCS	Residential Characteristics Study
RECS	Residential Energy Consumption Survey
RBSA	Residential Building Stock Assessment
RTF	Regional Technical Forum
T&D	Transmission and distribution
TLED	Tubular LED
TOU	Time of use
TRC	Total resource cost
TRM	Technical reference manual
UCT	Utility cost test
UES	Unit energy savings
WSEC	Washington State Energy Code

Executive Summary

Overview

This report presents the results of an independent assessment of the technical and achievable potential for electric and natural gas demand-side resources (DSR) in the service territory of Puget Sound Energy (PSE) over the 24-year electric planning horizon, from 2022 to 2045, and 20-year natural gas planning horizon, from 2022 to 2041. This conservation potential assessment (CPA), commissioned by PSE as part of its integrated resource planning (IRP) process, is intended to identify DSR potential from the perspectives of energy efficiency, demand response, and distributed generation (including solar photovoltaics and combined heat and power). The results of this assessment will help PSE identify cost-effective DSR and design future programming.

This study builds upon previous assessments of DSR resources in PSE's territory. It incorporates the latest baseline and DSR data from primary and secondary sources and is informed by the work of other entities in the region, such as the Northwest Power and Conservation Council (Council), the Northwest Regional Technical Forum (RTF), and the Northwest Energy Efficiency Alliance (NEEA). The methods used to evaluate the technical and achievable technical potential draw upon best utility industry practices and remain consistent with the methodology used by the Council in its assessment of regional conservation potentials in its most recently approved Seventh Northwest Conservation and Electric Power Plan (Seventh Plan). In addition, this work is also consistent with the draft 2021 Northwest Conservation and Electric Power Plan (2021 Plan) supply curves work that was under development as this assessment was being updated.

Scope of the Analysis and Approach

Energy Efficiency and Combined Heat and Power

The energy efficiency analysis included estimates of the technical and achievable technical potential for more than 400 unique electric and natural gas energy efficiency measures. Cadmus relied on PSE program data, RTF analysis, The Council's draft 2021 Plan and Seventh Plan analyses, and regional stock assessments to determine the savings, costs, and applicability for each measure. We incorporated feedback from PSE staff and regional stakeholders on the list of measures and measure assumptions.

Cadmus prepared 24-year forecasts of potential electric energy, peak demand, and a 20-year natural gas forecast of energy savings for each energy efficiency measure using a units-based method consistent with the Council's approach for its most recently approved plan (the Seventh Plan). The assessment considers multiple vintages (new and existing), distinguishes between lost opportunity and replace-on-burnout measures and accounts for building energy codes as well as future state and federal equipment standards. Achievable technical potential estimates use assumptions that are consistent with the Council's draft 2021 Plan: 85-100% of technical potential is achieved over the 24-year electric and 20-year natural gas study horizons, and adoption curves are derived from the Council's draft 2021 Plan ramp rates.

The combined heat and power (CHP) analysis identifies potential generation from nonrenewable and renewable CHP technologies in large commercial and industrial facilities. We derived estimates of CHP technical potential using generation and applicability data for reciprocating engines, microturbines, gas turbines, industrial biomass, and biogas. We determined achievable potential for these technologies using American Council for an Energy-Efficient Economy (ACEEE) CHP favorability data and an analysis of the U.S. Department of Energy (DOE) CHP Installation Database.

Demand Response

Demand response programmatic options seek to help reduce peak demand during system emergencies or periods of extreme market prices and to promote improved system reliability. Cadmus' analysis focused on program options that include residential direct load control (DLC) for space heat, room heat, water heat, and nonresidential load curtailment. These strategies include price- and incentive-based options for all major customer segments and end uses in PSE's service territory.

To estimate demand response potentials, this study applied a hybrid, top-down, and bottom-up approach that began by using utility system loads, disaggregated into sector, segment, and applicable end uses. For each program, we first assessed potential impacts at the end-use level then aggregated these to obtain estimates of technical potentials. This allowed us to apply market factors, such as likely program and event participation, to technical potentials to obtain estimates of market potentials.

A detailed discussion of the demand response potential is covered under section 2 of this report.

Distributed Solar Photovoltaics

The solar PV analysis uses power density forecasts and estimates of the total available roof area for solar PV to develop forecasts of nameplate capacity. Solar PV achievable potential was determined using a bass diffusion equation that incorporates data on the adoption of customer driven solar PV in PSE's service territory and future price and PV efficiency forecasts to estimate customer payback over time.

A detailed discussion of the distributed solar potential is covered under section 3 of this report.

Summary of Results

Table 1 shows the technical and achievable potential for each resource considered in this study. Electric DSRs represent nearly 608 average megawatts (aMW) of achievable technical potential and could produce approximately 1,192 MW of winter peak savings. Energy efficiency has the highest energy-savings potential, with 600 aMW of cumulative achievable technical potential by 2045. Cadmus identified natural gas cumulative achievable technical potential of 174 million therms. All estimates of potential in this report are presented at the generator, meaning they include line losses.

Table 1. Summary of Energy and Demand Savings Potential, Cumulative 2045

Resource	Energy (aMW/Million Therms)		Winter Coincident Peak Capacity (MW)	
	Technical Potential	Achievable Technical Potential	Technical Potential	Achievable Technical Potential
Electric Resources				
Energy Efficiency	706	600	1,127	958

Resource	Energy (aMW/Million Therms)		Winter Coincident Peak Capacity (MW)	
	Technical Potential	Achievable Technical Potential	Technical Potential	Achievable Technical Potential
Demand Response	N/A	N/A	N/A	226
Combined Heat and Power	200	8	200	8
Electric Resources Total	**906**	**608**	**1,327**	**1,192**
Natural Gas Resources				
Energy Efficiency	204	174	N/A	N/A

Figure 1. and Figure 2. present the respective electric and natural gas achievable potential forecasts. More savings are achieved for both fuels in the first 10 years of the study (2022 through 2031) than in the remaining years because the study assumes all discretionary measure potential savings (i.e., measures that retrofit existing homes and businesses) are acquired in the first 10 years. In the remaining years, additional savings come from lost opportunity measures, such as equipment replacement and new construction.

Figure 1. Electric Achievable Technical Potential Forecast, Cumulative 2022 - 2045

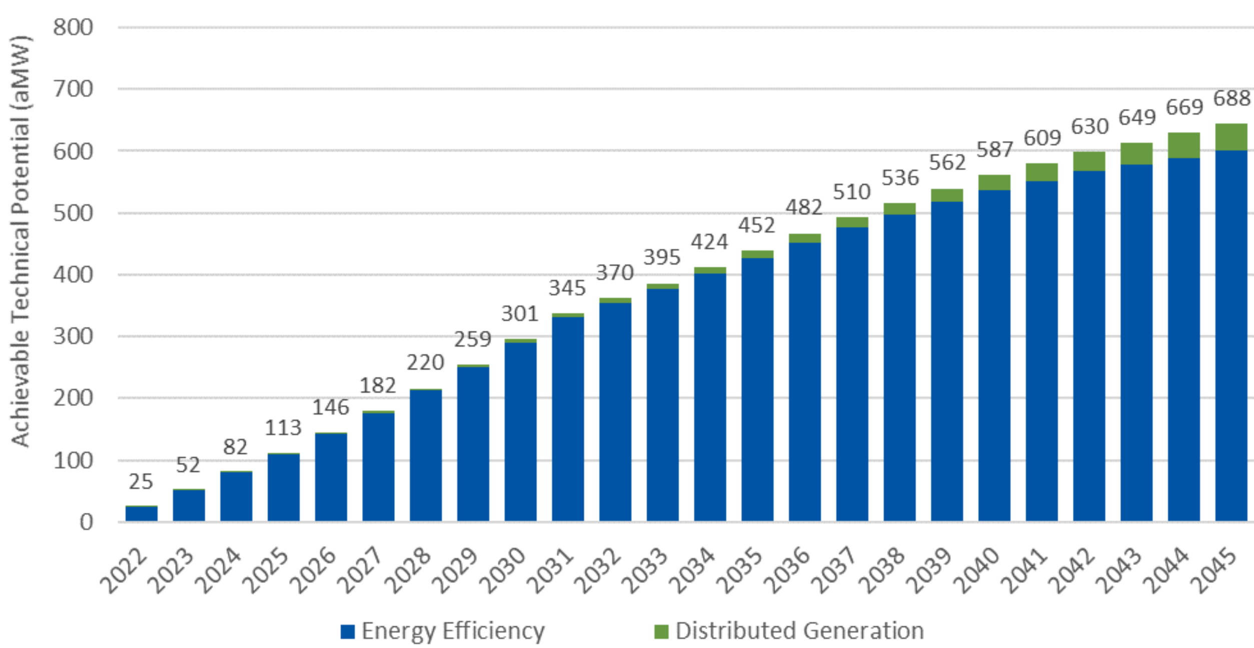
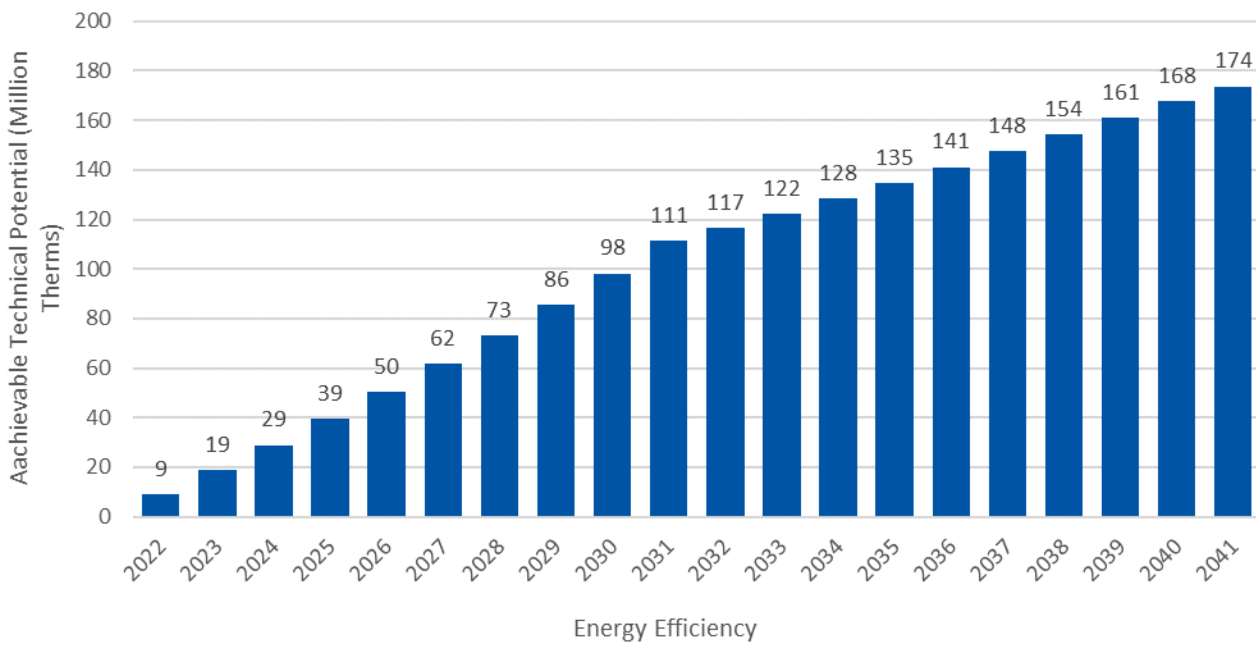


Figure 2. Natural Gas Achievable Potential Forecast, Cumulative 2022 - 2041



Energy Efficiency

The total achievable technical potential for electricity across all sectors is 600 aMW (Table 2). If the 24-year achievable potential is realized it will produce a load reduction equivalent to 18% of PSE's 2045 baseline electric sales. Approximately 56% of this potential is in the residential sector, 42% in the commercial sector, and the remaining 2% in the industrial sector.

Table 2. Electric Energy Efficiency by Sector, Cumulative 2045

Sector	2045 Baseline Sales (aMW)	Achievable Technical Potential	
		aMW	Percentage of Baseline Sales
Residential	1,846	339	18%
Commercial	1,339	250	19%
Industrial	122	10	8%
Total	**3,306**	**600**	**18%**

Cadmus identified approximately 174 million therms of natural gas energy efficiency achievable potential, with 147 million of these savings in the residential sector (Table 3). Overall natural gas achievable potential is equivalent to 15% of PSE's forecasted natural gas sales in 2041. Natural gas potentials were forecast out to 2041 while electricity was forecasted to 2045.

Table 3. Natural Gas Energy Efficiency by Sector, Cumulative 2041

Sector	2041 Baseline Sales (MM Therms)	Achievable Technical Potential	
		MM Therms	Percentage of Baseline Sales
Residential	757	147	19%

Sector	2041 Baseline Sales (MM Therms)	Achievable Technical Potential	
		MM Therms	Percentage of Baseline Sales
Commercial	362	25	7%
Industrial	22	2	8%
Total	**1,141**	**174**	**15%**

Comparison to 2019 CPA – Energy Efficiency

The 2021 energy efficiency analysis incorporates these changes since the completion of PSE's most recent previous CPA in 2019:

- Uses PSE's most recent F2020 Demand Forecast of energy and customers.
- Incorporates assumptions for savings, cost, and measure lives derived from PSE's 2020 measure business cases and RTF unit energy savings (UES) workbook updates as of January 31, 2020
- Uses the most recent PSE-specific and regional stock assessments to determine saturations and applicability, including PSE's 2017 Residential Characteristics Study (RCS), NEEA's 2018 Residential Building Stock Assessment (RBSA), and NEEA's 2014 Commercial Building Stock Assessment (CBSA)
- Accounts for changes to the Washington State Energy Code (WSEC) and Seattle Building Energy Code as well as recent changes to federal and Washington state equipment standards, including products added to state standards by legislation – House Bill 1444 (H.B. 1444) – passed in 2019 and signed into law by Governor Inslee
- Considers the impact of the Washington State Energy Performance Standard (HB1257) on commercial buildings by accelerating ramp rates for some commercial measures

Table 4 compares the 20-year achievable technical potential, expressed as a percentage of baseline sales, identified in the 2021 and 2019 CPAs. Overall, the 2021 CPA identified lower electric (-20%) and slightly lower natural gas (-2%) achievable technical potential.

Table 4. Energy Efficiency Comparison to Past CPAs

Study	20-Year Achievable Technical Potential (Percent of Sales)			Total Achievable Technical Potential (aMW and Million Therms)
	Residential	Commercial	Industrial	
Electric Resources				
2021 IRP	18%	18%	8%	552
2019 IRP	21%	16%	26%	692
Natural Gas Resources				
2021 IRP	19%	7%	8%	174
2019 IRP	20%	8%	17%	177

*This table compares 20-year results from 2021 CPA to the 2019 CPA. The 2021 CPA total electric achievable technical potential differs from the amount shown in Table 2, which presents the full 24-year electric potential study results

The following contribute to the significant decrease in electric energy efficiency potential:

- Exclusion of embedded data center measures which previously contributed 46 aMW of achievable potential in the 2019 CPA
- Updated forecast assumptions of the indoor cannabis market, previously assumed to grow at a rate of 3% per year within PSE's service territory, led to a 25 aMW reduction in potential (compared to the 2019 CPA)
- Incorporation of updated commercial LED lighting technology baselines, based on the Council's draft 2021 plan commercial lighting supply curves, which led to a 25 aMW reduction in potential (compared to the 2019 CPA)
- Re-classification of some industrial customers to the commercial sector
- Reductions in achievable potential due to the 2019 state equipment standards updates (HB 1444)

Combined Heat and Power

Table 5 illustrates the 24-year cumulative achievable technical potential from CHP technologies. Overall, Cadmus identified 7.8 aMW of potential from renewable and nonrenewable technologies.

Table 5. Combined Heat and Power Achievable Potential Summary, Cumulative 2045

CHP Type	Total Achievable Technical Potential (aMW)
Reciprocating Engine	4.0
Gas Turbine	1.1
Microturbine	1.0
Biogas (Anaerobic Digesters)	1.3
Industrial Biomass	0.4
Total	**7.8**

Comparison to 2019 CPA – CHP

Table 6 compares the 24-year cumulative CHP potential identified in the 2019 CPA to the 20-year cumulative CHP potential in the 2021 CPA. The decrease in CHP potential results from a lower, long-term electric commercial customer forecast compared to the 2019 CPA and re-allocation of commercial customer eligibility requirements across commercial building types.

Table 6. CHP Comparison to the 2019 IRP, Cumulative 2045 aMW

CHP Potential	2021 IRP	2019 IRP
Total	7.8	18

Demand Response

Table 7 presents the winter and summer peak achievable potential for demand response programs. Total 24-year winter demand response potential is 229 MW, which is equivalent to nearly a 4.5% reduction in PSE's forecasted 2045 winter peak.

Table 7. Demand Response Potential by Program, 2045

Product	Winter Achievable Potential (MW)	Percent of PSE System Peak (Winter)	Summer Achievable Potential (MW)	Percent of PSE System Peak (Summer)
Residential Critical Peak Pricing	66	1.3%	40	1.0%
Residential DLC Space Heating	53	1.1%	n/a	n/a
Residential DLC Space Cooling	n/a	n/a	55	1.4%
Residential DLC Water Heating	69	1.2%	69	1.7%
Commercial DLC Space Heating	12	0.2%	n/a	n/a
Commercial DLC Space Cooling	n/a	n/a	27	0.7%
Commercial and Industrial Curtailment	6	0.1%	8	0.2%
Commercial Critical Peak Pricing	2	< 0.1%	5	0.1%
Residential Electric Vehicle Service Equipment	9	0.2%	9	0.2%
Residential Behavioral	9	0.2%	5	0.1%
Total	**226**	**4.5%**	**218**	**5.4%**

Comparison to 2019 CPA – Winter Demand Response

Table 8 compares the demand response potential identified in the 2021 and 2019 CPAs, by sector. Overall, the 2021 CPA identified 7 MW less winter peak potential compared to 2019. Even though the total winter peak potential of 2021 and 2019 are comparable, it can be seen that the segment share of that potential has changed. Several factors contributed to higher residential demand response potential, including updates to end-use saturations for water heat, revised peak impacts from recent demand response evaluations, and the inclusion of new products (for instance, the 2021 CPA considered a residential behavioral product that was not considered in the 2019 study).

Table 8. Demand Response Achievable Potential Comparison of 2019 CPA and 2017 CPA

Sector	2021 CPA (MW)	2019 CPA (MW)	2017 CPA (MW)
Residential	206	180	109
Commercial and Industrial	20	53	79
Total	**226**	**233**	**188**

The following contribute to the decrease in commercial and industrial demand response potential:

- Revisions to customer participation assumptions for commercial and industrial demand curtailment, consistent with the Council's draft 2021 Plan demand response supply curves
- Updates to per event demand impacts for commercial and industrial demand curtailment, consistent with the Council's draft 2021 Plan demand response supply curves

Distributed Solar PV and Comparison to the 2019 CPA

Cadmus identified 87 MW of solar PV nameplate capacity achievable potential in the residential sector and 249 MW in the commercial sector (336 MW total). This is higher than the 231 MW of solar PV achievable potential identified in the 2019 assessment (Table 9) and is equivalent to 9.4 aMW and 26.8 aMW of cumulative achievable energy potential for the residential, and commercial sectors, respectively. The increase in solar PV potential is primarily the result of lower estimated costs for residential and commercial systems due to updated data sources.

Table 9. Solar PV Achievable Potential Comparison to 2019 IRP

Sector	Achievable Potential (MW)	
	2021 IRP	2019 IRP
Residential	87	34
Commercial and Industrial	249	196
Total	**336**	**231**

Incorporating DSR into PSE's IRP

The achievable technical potentials for EE and CHP shown above have been grouped by the levelized cost of conserved energy for inclusion in PSE's IRP model. These costs have been calculated over a 24-year program life for electric resources and over a 20-year program life for gas resources; the *Calculate Levelized Costs* section provides additional detail on the levelized cost methodology. Bundling resources into a number of distinct cost groups allows the model to select the optimal amount of annual DSR, based on expected load growth, energy prices, and other factors.

Cadmus spread the annual savings estimates over 8760-hour load shapes to produce hourly DSR bundles. In addition, we assumed savings are gradually acquired over the year, as opposed to instantly on the first day of January. PSE provided intra-year DSR acquisition schedules, which we used to ramp hourly savings across months. Figure 3. shows the annual cumulative combined potential for energy efficiency and combined heat and power by each cost bundle considered in PSE's 2021 IRP. Figure 4. shows annual DSR bundles for natural gas energy efficiency.

Figure 3. Electric Supply Curve – Cumulative 24-Year Achievable Potential

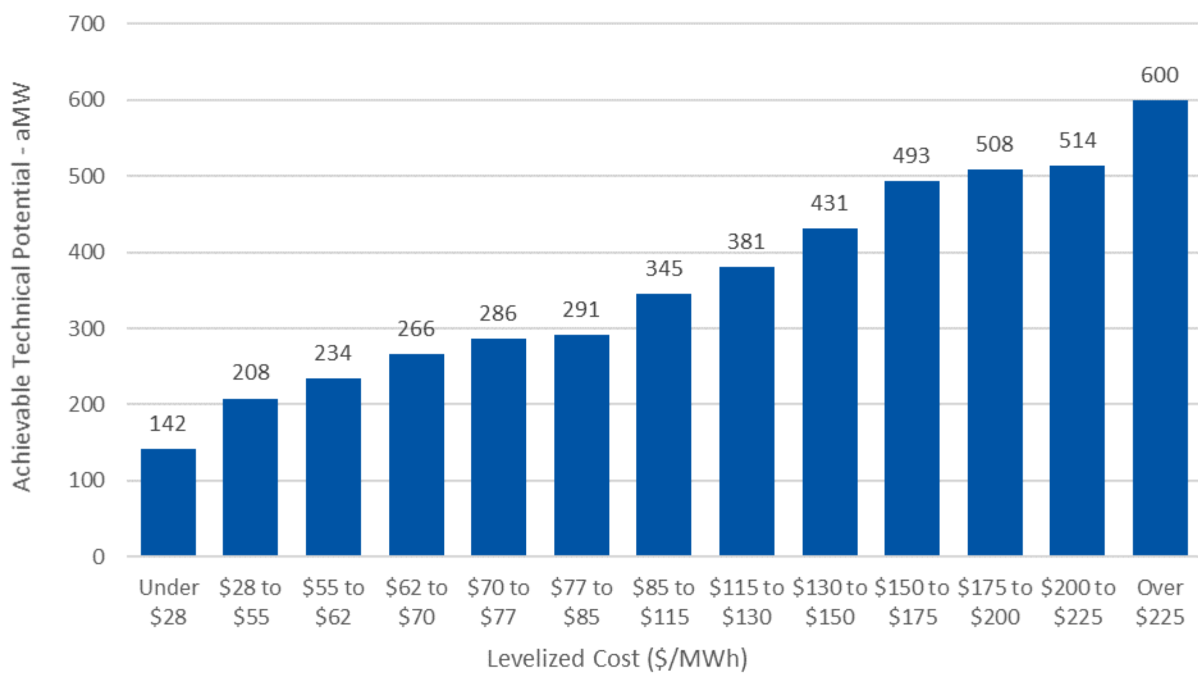
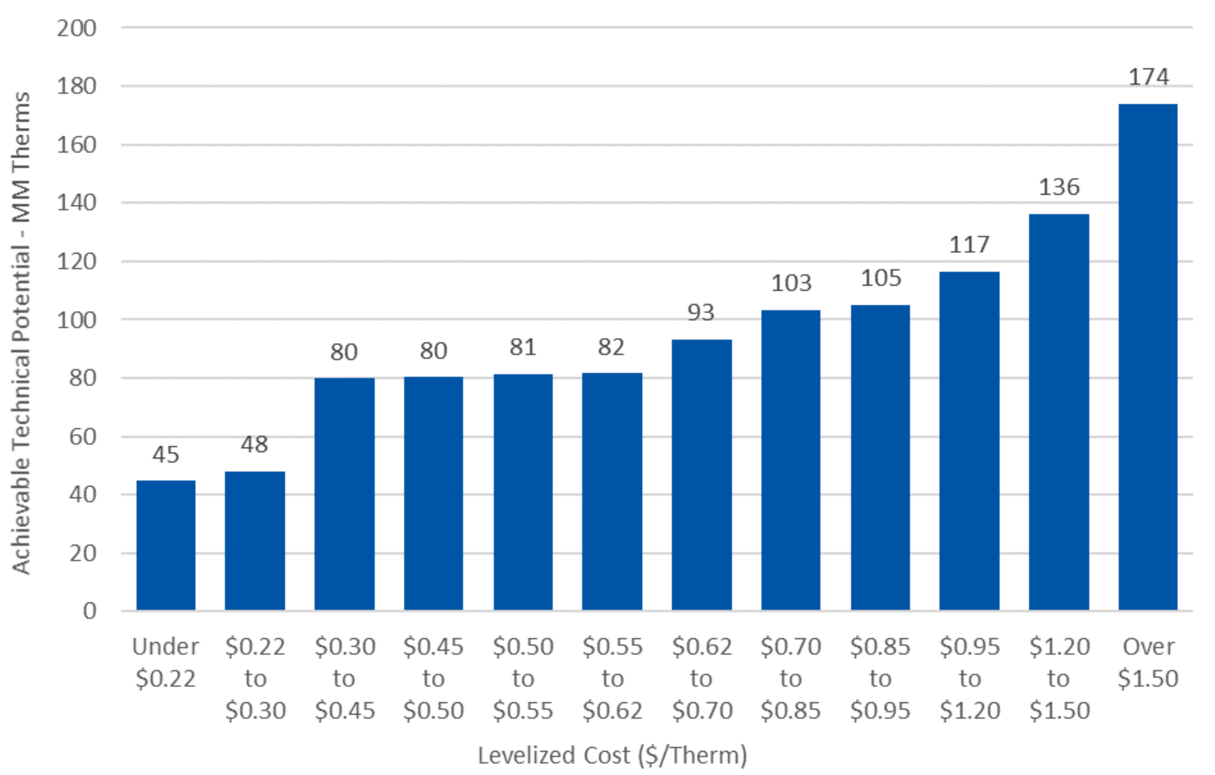


Figure 4. Natural Gas Supply Curve – Cumulative 20-Year Achievable Potential



Similarly, Cadmus spread the annual savings estimates for distributed solar over 8760-hour load shapes to produce hourly DSR bundles. These savings were input without any costs in the IRP, as these programs are customer driven and the IRP does not determine the cost-effective potential; the IRP accounts for the reductions to the demand forecast only.

Finally, the demand response programs are a capacity-only resource and were grouped by program and annual capacity. The capacities are cumulated over each year of the study, and the program costs are input as annual, incremental costs associated with the peak demand reductions that are added in a particular year.

Organization of This Report

This report has been organized in three main sections, and an appendix:

- Energy efficiency and combined heat and power
- Demand response, and
- Distributed solar PV
- Appendix A. IRP Sensitivities

Section 1. Energy Efficiency and Combined Heat and Power

This section describes Cadmus' methodology for estimating demand-side resources (DSR) potential in PSE's service territory between 2022 and 2045 and for developing supply curves for modeling DSR in PSE's integrated resource planning (IRP). We describe the calculations for technical and achievable technical potential, identify the data sources for components of these calculations, and discuss key global assumptions. Estimating DSR potential involves analyzing many conservation measures across many sectors, with each measure requiring nuanced analysis. This section does not describe the detailed approach for estimating a specific measure's unit energy savings (UES) or cost, but it does show the general calculations that were used for nearly all measures.

Overview of Technical and Achievable Potential

Cadmus assessed two types of potential—technical and achievable technical. PSE will determine a third potential—achievable economic—through the IRP's optimization modeling. The three types of potential are described as follows:

- ***Technical potential*** assumes that all technically feasible resource opportunities may be captured, regardless of their costs or other market barriers. It represents the total DSR potential in PSE's service territory, after accounting for purely technical constraints.
- ***Achievable technical potential*** is the portion of technical potential that is assumed to be achievable during the study's forecast, regardless of the acquisition mechanism. For example, savings may be acquired through utility programs, improved codes and standards, and market transformation.
- ***Achievable economic potential*** is the portion of achievable technical portion determined to be cost-effective by the IRP's optimization modeling, in which either bundles or individual DSR measures are selected based on cost and savings. The cumulative potential for these selected bundles constitutes achievable economic potential.

Cadmus provided PSE with forecasts of achievable technical potential, which were then entered as variables in the IRP's optimization model to determine achievable economic potential.

Figure 5. illustrates the three types of energy efficiency potential.

Figure 5. Types of Energy Efficiency Potential

The timing of resource availability is also a key consideration in determining conservation potential. There are two distinct categories of resources:

- ***Discretionary resources*** are retrofit opportunities in existing facilities that, theoretically, are available at any point over the study period. Discretionary resources are also referred to as retrofit measures. Examples include weatherization and shell upgrades, economizer optimization, and low-flow showerheads.
- ***Lost-opportunity resources***, such as conservation opportunities in new construction and replacements of equipment upon failure (natural replacement), are nondiscretionary. These resources become available according to economic and technical factors beyond a program administrator's control. Examples of natural replacement measures include HVAC equipment, water heaters, appliances, and replace-on-burnout lighting fixtures.

Cadmus used a units-based approach to forecast energy efficiency potential in the residential and commercial sectors. This approach involved first estimating the number of units of an energy efficiency measure that are likely to be installed in each year then multiplying these unit forecasts by the measure's UES.

For the industrial sector, Cadmus used a top-down method calculating technical potential as a percentage reduction to the baseline industrial forecast. Baseline end-use loads are first estimated for each industrial segment, then the potential is calculated using estimates of each measures' end-use percentage savings.

Steps for Estimating Energy Efficiency Potential

Cadmus followed this series of steps, described in detail below this list, to estimate energy efficiency potential:

1. ***Market segmentation.*** This involved identifying the sectors and segments for estimating energy efficiency potential. Segmentation accounts for variation across different parts of PSE's service territory and across different applications of energy efficiency measures.
2. ***Develop efficiency measure dataset.*** This required research into viable energy efficiency measures that can be installed in each segment. The description for this step below includes the components and data sources for estimating measure savings, costs, applicability factors, lifetimes, baseline assumptions, and the treatment of federal standards.
3. ***Develop unit forecasts.*** Unit forecasts vary by sector—number of homes for residential, square footage of floor space for commercial, energy for industrial, and poles for street lighting—and reflect the number of units that could be installed for each measure. Cadmus developed sector-specific methodologies to determine the number of units.
4. ***Calculate levelized costs.*** IRP modeling requires levelized costs for each measure, and in aggregate, to compare energy conservation to supply-side resources. The components and assumptions for the levelized-cost calculations are discussed below.
5. ***Forecast technical potential.*** Technical potential forecasts rely on the sector-specific unit forecasts and the measure data compiled from prior steps. The description below presents the general equation we used for calculating technical potential.
6. ***Forecast achievable technical potential.*** Achievable technical potential forecasts use an equation like the one we used to determine technical potential forecasts, with additional terms (described below) to account for market barriers and ramping.
7. ***Develop IRP inputs.*** Forecasts of achievable technical potential were bundled by levelized costs, so PSE's IRP modelers can consider energy efficiency as a resource within the IRP.

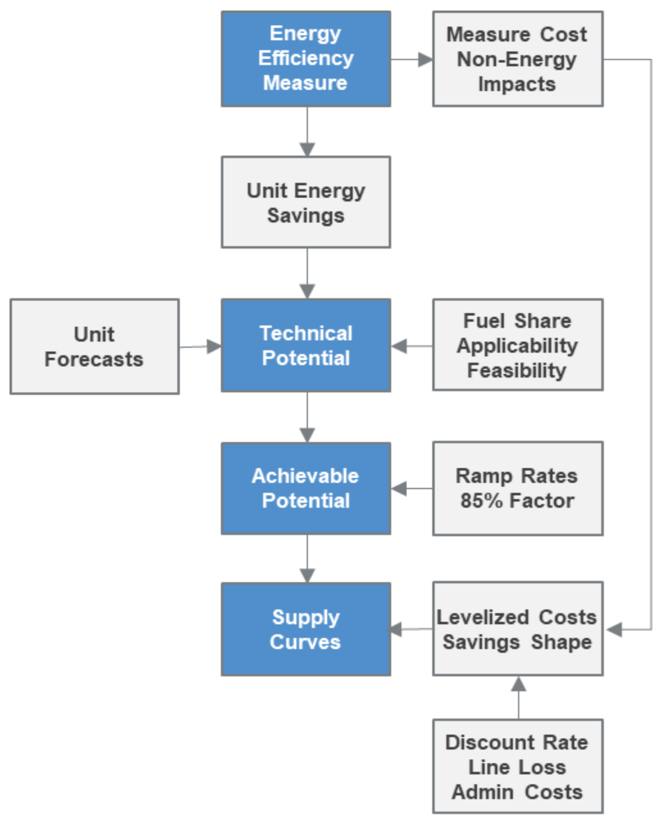


Figure 6. Overview of Energy Efficiency Methodology

Figure 6. provides a general overview of the process and inputs required to estimate potential and develop conservation supply curves.

Segmentation

Market segmentation involves first dividing PSE's gas and electric service territories into sectors and market segments. Careful segmentation accounts for variation in building characteristics and savings across the service territory. To the extent possible, energy efficiency measure inputs reflect primary data, such as the NEEA's 2014 Commercial Building Stock Assessment (CBSA), the 2018 Residential Building Stock Assessment (RBSA), and PSE's Residential Characteristics Study (RCS).

Considering the benefits and drawbacks of different segmentation approaches, Cadmus identified three parameters that produce meaningful and robust estimates:

- ***Service territories and fuel.*** PSE's respective natural gas and electric service territories
- ***Sector.*** Residential, commercial, industrial, and street lighting
- ***Industries and building types.*** Three residential (with the corresponding low income (LI)) segments, 19 commercial, 19 industrial, and one street lighting segments

Table 10 lists the segments modeled for each sector.

Table 10. Segments Modeled

Residential	Commercial	Industrial
Single Family	Large Office	Mechanical Pulp
Multifamily	Medium Office	Kraft Pulp
Manufactured	Small Office	Paper
Multifamily Low Income	Extra Large Retail	Foundries
Manufactured Low Income	Large Retail	Food - Frozen
Single Family Low Income	Medium Retail	Food - Other
	Small Retail	Wood - Lumber
	School K-12	Wood - Panel
	University	Wood - Other
	Warehouse	Sugar
	Supermarket	Hi Tech - Chip Fabrication
	Mini-Mart	Hi Tech - Silicon
	Restaurant	Metal Fabrication
	Lodging	Transportation Equipment
	Hospital	Refinery
	Residential Care	Cold Storage
	Assembly	Fruit Storage
	Other	Chemical
	Indoor Agriculture	Miscellaneous Manufacturing
	Wastewater	Streetlighting

Energy Efficiency Measure Characterization

Overview and Components

Cadmus compiled energy efficiency datasets that include the UES, costs, measure lives, non-energy impacts, and applicability factors for each energy conservation measure. These datasets include several details for each measure permutation:

- ***Unit energy savings (UES).*** UES are a conservation measure's annual per-unit kilowatt-hour and/or therm savings. Cadmus relied on UES values from PSE's internal measure business cases, RTF UES workbooks, the Seventh Plan, and a limited set of draft 2021 Plan supply curves
- ***Costs and non-energy impacts.*** Costs include the incremental per-unit equipment (capital), labor, annual incremental operations and maintenance (O&M), and periodic (or avoided periodic) re-installation costs associated with installing an energy efficiency measure. Non-energy impacts are the annual dollar savings per year associated with quantifiable non-energy benefits (such as water).
- ***Effective useful lives (EUL).*** EUL is the expected lifetime (in years) for an energy efficiency measure from PSE's measure business cases, the Seventh Plan, draft 2021 Plan, or RTF.
- ***Applicability factors.*** Applicability factors reflect the percentage of installations that are technically feasible and the current saturation of an efficiency measure.
- ***End-use savings percentage (industrial only).*** The industrial sector's top-down approach to estimating potential requires assessments of the end-use percentage savings for each energy conservation measure. We relied on estimates included in the Council's Seventh Plan industrial tool for these values.
- ***Savings shape.*** We assigned an hourly savings shape to each measure, which we then used to disaggregate annual forecasts of potential into hourly estimates.

Accounting for Codes and Standards

Cadmus accounted for building energy codes and equipment standards by either embedding the impact of the standard in the UES estimate for above-standard equipment and/or by excluding measures that will be captured by the current code or standard. Cadmus accounted for the 2018 Washington State energy code (WSEC), effective November 1, 2020 for the residential and commercial sectors.

Table 11 and Table 12 list the federal and state electric and natural gas standards and their effective dates, respectively, that Cadmus considered. Most of these standards have either already been adopted or are scheduled to go into effect before this study's 2022 start date. Thus, equipment that meets the specifications of each respective standard were not included in estimates of energy efficiency potential. Generally, accounting for these standards reduced the total conservation potential.

Table 11. Electric Federal and State Standards

Equipment Electric Type	New Standard	Sectors Impacted	Study Effective Date
Clothes Washer (top loading)	Federal standard 2015	Residential	March 7, 2015
Clothes Washer (front loading)	Federal standard 2018	Residential	January 1, 2018
Clothes Washer (commercial sized)	1. Federal standard 2013	Nonresidential	1. January 8, 2013

Equipment Electric Type	New Standard	Sectors Impacted	Study Effective Date
	2. Federal standard 2018		2. January 1, 2018
Computers	State standard 2019	Nonresidential/Residential	January 1, 2021
Dehumidifier	1. Federal standard 2012 2. Federal standard 2019	Residential	1. October 1, 2012 2. June 13, 2019
Dishwasher	Federal standard 2013	Residential	May 30, 2013
Dishwasher (commercial)	State standard 2019	Nonresidential	January 1, 2021
Dryer	Federal standard 2015	Residential	January 1, 2015
Uninterruptible (External) Power Supplies	1. Federal standard 2016 2. Federal standard 2017 3. State standard 2019	Nonresidential/Residential	1. February 10, 2016 2. July 1, 2017 3. January 1, 2021
Freezer	Federal standard 2014	Residential	September 15, 2014
Microwave	Federal standard 2016	Residential	June 17, 2016
Fryers and Steam Cookers	State standard 2019	Nonresidential	January 1, 2021
Refrigerator	Federal standard 2014	Residential	September 15, 2014
Automatic Commercial Ice Makers	1. Federal standard 2010 2. Federal standard 2018	Nonresidential	1. January 1, 2010 2. January 28, 2018
Commercial Refrigeration Equipment (semi-vertical and vertical cases)	1. Federal standard 2010 2. Federal standard 2012 3. Federal standard 2017	Nonresidential	1. January 1, 2010 2. January 1, 2012 3. March 27, 2017
Vending Machine	1. Federal standard 2012 2. Federal standard 2019	Nonresidential	1. August 31, 2012 2. January 8, 2019
Walk-in Cooler Walk-in Freezer	1. Federal standard 2014 2. Federal standard 2017	Nonresidential	1. August 4, 2014 2. June 5, 2017
Central Air Conditioner	Federal standard 2015 (no change for Northern region)	Residential	January 1, 2015
Heat Pump (air source)	Federal standard 2015	Residential	January 1, 2015
Packaged Terminal Air Conditioner and Heat Pump	1. Federal standard 2012 2. Federal standard 2017	Nonresidential	1. October 8, 2012 2. January 1, 2017
Room Air Conditioner	Federal standard 2014	Residential	June 1, 2014
Single Package Vertical Air Conditioner and Heat Pump	1. Federal standard 2010 (phased in over six years) 2. Federal standard 2019	Nonresidential	1. January 1, 2010 2. September 23, 2019
Small, Large, and Very Large Commercial Package Air Conditioner and Heat Pump	1. Federal standard 2010 2. Federal standard 2018 3. Federal standard 2023	Nonresidential	1. January 1, 2010 2. January 1, 2018 3. January 1, 2023
Fluorescent Lamp Ballast	Federal standard 2014	Nonresidential	November 14, 2014
General Service Fluorescent Lamp	1. Federal standard 2012 2. Federal standard 2018	Nonresidential	1. July 14, 2012 2. January 26, 2018
Lighting General Service and Specialty Lamp	State standard 2019	Nonresidential/Residential	January 1, 2021
Metal Halide Lamp Fixture	Federal standard 2017	Nonresidential	February 10, 2017
Electric Motor (small)	Federal standard 2015	Nonresidential	March 9, 2015
Electric Motor	1. Federal standard 2010 2. Federal standard 2016	Nonresidential	1. December 19, 2010 2. June 1, 2016
Furnace Fan	Federal standard 2019	Residential	July 3, 2019
Pump	Federal standard 2020	Nonresidential	January 27, 2020
Pre-Rinse Spray Valve	Federal standard 2019	Nonresidential	January 28, 2019
Showerhead	State standard 2019	Nonresidential/Residential	January 1, 2021
Water Heater > 55 Gallons	Federal standard 2015	Nonresidential/Residential	April 16, 2015
Water Heater ≤ 55 Gallons	Federal standard 2015	Nonresidential/Residential	April 16, 2015

Table 12. Natural Gas Federal and State Standards

Equipment Natural Gas Type	New Standard	Sectors Impacted	Standard Effective Date
Boiler (residential sized)	1. Federal standard 2012	Nonresidential/ Residential	1. September 1, 2012
	2. Federal standard 2021		2. January 15, 2021
Clothes Washer (top loading)	Federal standard 2015	Residential	March 7, 2015
Clothes Washer (front loading)	Federal standard 2018	Residential	January 1, 2018
Clothes Washer (commercial sized)	1. Federal standard 2013	Nonresidential	1. January 8, 2013
	2. Federal standard 2018		2. January 1, 2018
Dishwasher	Federal standard 2013	Residential	May 30, 2013
Dryer	Federal standard 2015	Residential	January 1, 2015
Furnace (residential sized)	Federal standard 2015	Nonresidential/ Residential	November 19, 2015
Pool Heater	Federal standard 2013	Residential	April 16, 2013
Pre-Rinse Spray Valve	Federal standard 2019	Nonresidential	January 28, 2019
Showerhead	State standard 2019	Nonresidential/ Residential	January 1, 2021
Water Heater > 55 Gallons	Federal standard 2015	Nonresidential/ Residential	April 16, 2015
Water Heater ≤ 55 Gallons	Federal standard 2015	Nonresidential/ Residential	April 16, 2015

Baseline Units Forecast

General Approach

Cadmus developed a 24-year forecast (2022 through 2045) of the number of electric units and a 20-year forecast (2022 through 2041) of the number of gas units that could feasibly be installed for each permutation of each energy efficiency measure researched in the previous step. Separate unit forecasts were developed for two types of lost opportunity measures (natural replacement and new construction) and one type of discretionary measures (retrofit):

- ***Natural replacement (lost opportunity) measures*** are installed when the equipment it replaces reaches the end of its EUL. Examples include appliances (such as clothes washers and refrigerators) and HVAC equipment (such as heat pumps and chillers).
- ***New construction (lost opportunity) measures*** are applied to homes and buildings that will be constructed over the study forecast. The unit forecast for new construction is driven by anticipated new home and new commercial construction, which we derived from utility customer forecasts and draft 2021 Plan regional forecasts.
- ***Retrofit (discretionary) measures*** encompass existing equipment or building upgrades that can theoretically be completed any time over the study forecast. Unlike natural replacement measures, the timing of retrofit savings is not determined by turnover rates. Examples of retrofit measures include weatherization and controls.

To determine measure-specific unit forecasts (used to estimate technical potential), four factors were considered:

- ***Sector unit forecasts*** are estimates of the number of homes (residential) or square footage of floor space (commercial) derived from PSE's customer database and load forecast data.

- ***Measure saturations (units per sector unit)*** are estimates of the number of units per sector unit (per home or per square foot) in PSE's natural gas and electric service territories. Where possible, Cadmus calculated these using data from the PSE 2017 RCS, CBSA, and RBSA.
- ***Applicability factors (technical feasibility percentage and measure competition share)*** are the percentage of homes or buildings that can feasibly receive the measure and the percentage of eligible installations, after accounting for competition with similar measures.
- ***Turnover rates (for natural replacement measures)*** are used to determine the percentage of units that can be installed in each year for natural replacement measures. The turnover rate equals 1 divided by the measure EUL.

Figure 7 illustrates the general equation Cadmus used to determine the number of units for each measure over the study forecast horizon. By default, the turnover rate for retrofit and new construction measures is 100%. (Turnover is not accounted for in these permutations.)

Figure 7. Unit Forecast Equation

To determine unit forecasts, Cadmus relied on data that represent PSE's service territories, as shown in Table 13. Following the table, we describe our approach for developing unit forecasts in each sector.

Table 13. Unit Forecast Components and Data Sources

Component	Data Source
Sector Units	PSE and U.S. Energy Information Administration (EIA) 861 data; U.S. Census Bureau American Community Survey; PSE RCS sample design file; PSE CIS data
Saturation	PSE 2017 RCS; Regional stock assessments (RBSA and CBSA)
Applicability Factor	PSE 2017 RCS; Regional stock assessments (RBSA and CBSA)
Turnover Rate	PSE, RTF, draft 2021 Plan, and Seventh Plan measure workbooks

Calculate Levelized Costs

Identified potential is grouped by levelized cost over a 24-year study horizon for electric resources and a 20-year horizon for natural gas resources, which allows PSE's IRP model to pick the optimal DSR amount, given various assumptions regarding future resource requirements and costs. The 24-year electric levelized-cost and 20-year natural gas levelized-cost calculations incorporate numerous factors, which are consistent with the Council's methodology and shown in Table 14.

Table 14. Levelized Cost Components

Type	Component
Costs	Incremental Measure Cost
	Incremental O&M Cost*
	Administrative Adder
Benefits	Present Value of Non-Energy Benefits
	Present Value of T&D Deferrals**
	Conservation Credit
	Secondary Energy Benefits

*Some measures may have a reduction in O&M costs, which is a benefit in the levelized cost calculation.
**For natural gas, this includes the deferred gas distribution benefits

In addition to the upfront capital cost and annual energy savings, the levelized-cost calculation incorporates several other factors, consistent with the Council's methodology:

- ***Incremental measure cost.*** This study considers the costs required to sustain savings over a 24-year horizon, including reinstallation costs for measures with useful lives less than 24 years. If a measure's useful life extends beyond the end of the 24-year study, Cadmus incorporates an end effect that treats the levelized cost of that measure over its EUL as an annual reinstallation cost for the remainder of the 24-year period.[1,2,3]

  For example, Figure 8 shows the timing of initial and reinstallation costs for an electric measure with a ten-year lifetime in context with the 24-year electric study horizon. The measure's final lifetime in this study ends after the study horizon, so the final four years (Year 21 through Year 24) are treated differently by leveling measure costs over its ten-year useful life and treating these as annual reinstallation costs.

Figure 8. Illustration of Capital and Reinstallation Cost Treatment

	Year																							
Component	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Initial Capital Cost																								
Re-Installation Cost																					End Effect			

- ***Incremental operations and maintenance (O&M) benefits or costs.*** As with incremental measure costs, O&M costs are considered annually over the 24-year horizon. The present value

1 In this context, EUL refers to levelizing over the measure's useful life. This is equivalent to spreading incremental measure costs over its EUL in equal payments assuming a discount rate equal to PSE's weighted average cost of capital (6.80%).

2 This method is applied both to measures with a useful life of greater than 24 years and measures with a useful life that extends beyond study horizon at time of reinstallation.

3 This method also applies to the 20-year natural gas study horizon.

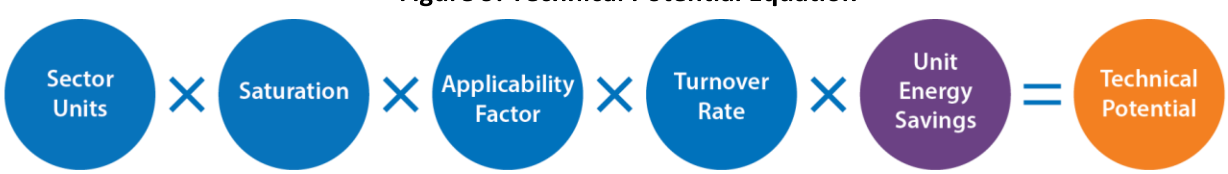
is used to adjust the levelized cost upward for measures with costs above baseline technologies and downward for measures that decrease O&M costs.

- ***Administrative adder.*** Cadmus assumed a program administrative cost equal to 20% of incremental measure costs for electric and gas measures across all sectors.
- ***Non-energy benefits.*** These benefits are treated as a reduction in levelized costs for measures that save resources, such as water or detergent. For example, the value of reduced water consumption due to the installation of a low-flow showerhead reduces the levelized cost of that measure.
- ***The regional 10% conservation credit, capacity benefits during PSE's system peak, and transmission and distribution (T&D) deferrals.*** These are similarly treated as reductions in levelized cost for electric measures. The addition of this credit per the Northwest Power Act is consistent with Council's methodology and is effectively an adder to account for unquantified external benefits of conservation when compared to other resources.[4]
- ***Secondary energy benefits.*** These benefits are treated as a reduction in levelized costs for measures that save energy on secondary fuels. This treatment is necessitated by Cadmus' end-use approach to estimating technical potential. For example, consider the cost for R-60 ceiling insulation for a home with a gas furnace and an electric cooling system. For the gas furnace end use, Cadmus considers the energy savings that R-60 insulation produces for electric cooling systems, conditioned on the presence of a gas furnace, as a secondary benefit that reduces the levelized cost of the measure. This adjustment impacts only the measure's levelized costs; the magnitude of energy savings for the R-60 measure on the gas supply curve is not impacted by considering secondary energy benefits.

Forecast Technical Potential

After compiling UES estimates and developing unit forecasts for each permutation of each energy efficiency measure, Cadmus multiplied the two to create 24-year forecasts of technical potential beginning in 2022. Figure 9 shows the equation for calculating technical potential. Blue components make up the measure unit calculation (shown previously in Figure 7.).

Figure 9. Technical Potential Equation



[4] Northwest Power & Conservation Council. January 1, 2010. "Northwest Power Act." http://www.nwcouncil.org/library/poweract/default.htm.

Forecast Achievable Potential

Achievable technical potential equals the product of a unit forecast, the measure UES, the maximum achievability factor, and ramp rate factors (Figure 10). Blue components are a part of the measure unit calculation. The purple component is a part of the technical potential calculation. The blue, purple, and orange components make up the achievable potential calculation.

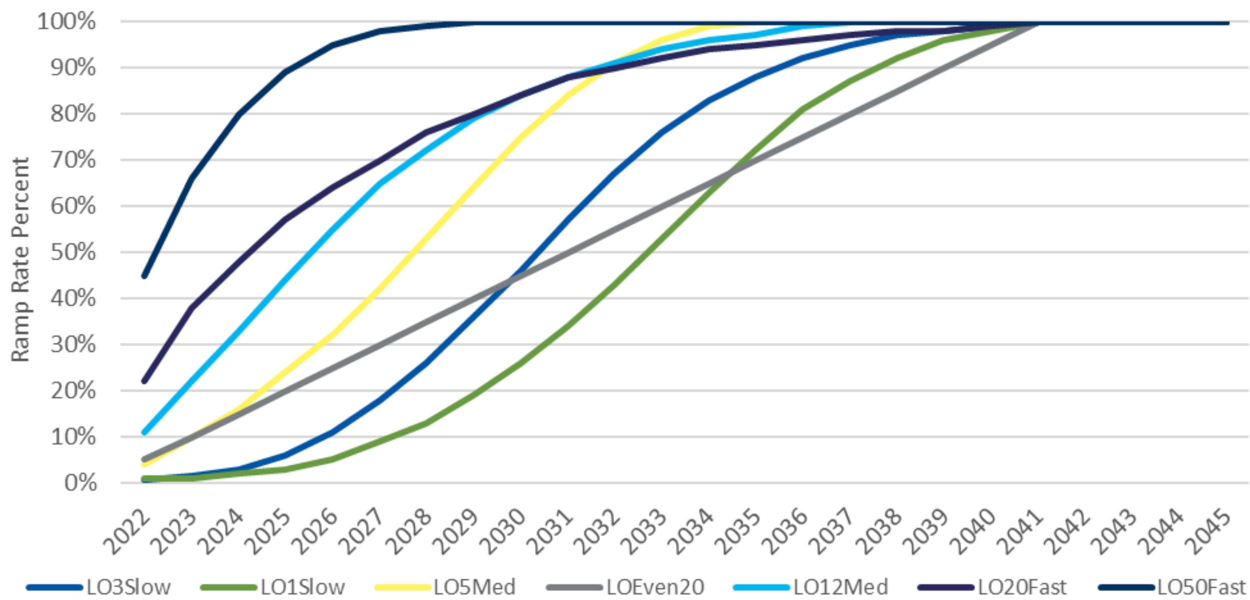
Figure 10. Equation for Estimating Achievable Technical Potential

As illustrated in Figure 10, achievable technical potential is the product of technical potential and both the maximum achievability factor and the ramp rate percentage. Cadmus used maximum achievability factors from the Council's draft 2021 Plan supply curves. Ramp rates are measure-specific and were based on the ramp rates developed for the Council's draft 2021 Plan supply curves but were adjusted to account for this study's 2022 to 2045 horizon.

For discretionary measures, Cadmus assumed all savings are acquired at an even rate over the first 10 years of the study. In other words, achievable potential for discretionary measures equals one-tenth of the total cumulative achievable potential in each of the first 10 years of the study (2022 through 2031). After 2031, there is no additional potential from discretionary measures.

For lost opportunity measures, we used the same ramp rates as those developed by the Council for its draft 2021 Plan supply curves. However, the draft 2021 Plan ramp rates cover only the 2022 to 2041 period of this study's horizon. Because nearly all lost opportunity ramp rates approach 100%, we set ramp values for 2041 through 2045 to equal the 2041 value from the Council's draft 2021 Plan. Figure 11 illustrates the lost opportunity ramp rates.

Figure 11. Lost Opportunity Ramp Rates



Develop IRP Inputs

Cadmus developed energy efficiency supply curves to allow PSE's IRP optimization model to identify the cost-effective level of energy efficiency. PSE's optimization model required hourly forecasts of electric energy efficiency potential and monthly forecasts of gas potential. To produce these hourly forecasts, we applied hourly end use load profiles shapes to annual estimates of achievable technical potential for each measure. These hourly end use load profiles are generally the same as those used by the Council in its draft 2021 Plan supply curves and by the RTF in its UES measure workbooks (including generalized shapes that we expanded to hourly shapes).

Cadmus worked with PSE to determine the format of inputs into the IRP model. We grouped energy efficiency and CHP potential into the levelized costs bundles shown in Table 15 and Table 16. Whereas the 2019 CPA included only 10 bundles – with the highest cost bundle representing energy efficiency potential at a net total resource cost (TRC) levelized cost greater than $150 per megawatt-hour – the 2021 CPA update includes three additional bundles which add greater granularity for more expensive resources. The number and delineating values of the natural gas levelized cost bundles remain unchanged from the 2019 CPA.

Table 15. Electric Levelized Cost Bundles

Bundle	Electric Bundle ($/kWh)
1	($9,999.000) to $0.028
2	$0.028 to $0.055
3	$0.055 to $0.062
4	$0.062 to $0.070
5	$0.070 to $0.077
6	$0.077 to $0.085
7	$0.085 to $0.115

Bundle	Electric Bundle ($/kWh)
8	$0.115 to $0.130
9	$0.130 to $0.150
10	$0.150 to $0.175
11	$0.175 to $0.200
12	$0.200 to $0.225
13	$0.225 to $999.00

Table 16. Natural Gas Levelized Cost Bundles

Bundle	Natural Gas Bundle ($/Therm)
1	($9,999.00) to $0.22
2	$0.22 to $0.30
3	$0.30 to $0.45
4	$0.45 to $0.50
5	$0.50 to $0.55
6	$0.55 to $0.62
7	$0.62 to $0.70
8	$0.70 to $0.85
9	$0.85 to $0.95
10	$0.95 to $1.20
11	$1.20 to $1.50
12	$1.50 to $999.00

Energy Efficiency Potential

Scope of Analysis

PSE requires accurate estimates of technically-achievable energy efficiency potential because they are essential for its IRP and program planning efforts. PSE then bundles these potentials in terms of levelized costs of conserved energy so the IRP model can determine the optimal amount of energy efficiency potential PSE should select.

To support these efforts, Cadmus performed an in-depth assessment of technical potential and achievable technical potential for electric and natural gas resources in the residential, commercial, and industrial sectors. The next section is in two parts—the first summarizes resource potential by fuel and sector and the second presents detailed results by fuel and sector.

Summary of Resource Potential – Electric

Table 17 shows 2045 forecasted baseline electric sales and potential by sector.[5] Cadmus' analysis indicates that 706 average megawatts (aMW) of technically feasible electric energy efficiency potential will be available by 2045, the end of the 24-year planning horizon, which translates to an achievable

5 These savings derive from forecasts of future consumption, absent any utility program activities. Note that consumption forecasts account for the savings PSE has acquired in the past, but the estimated potential is inclusive of—not in addition to—current or forecasted program savings.

technical potential of 600 aMW. Should all this potential prove cost-effective and realizable, it will result in an 19% reduction in 2045 forecasted retail sales.

Table 17. Electric 24-Year Cumulative Energy Efficiency Potential

Sector	2045 Baseline Sales (aMW)	Achievable Technical Potential	
		aMW	Percentage of Baseline Sales
Residential	1,846	339	18%
Commercial	1,339	250	19%
Industrial	122	10	8%
Total	**3,306**	**600**	**19%**

Figure 12 shows each sector's relative share of the overall electric energy efficiency achievable technical potential. The residential sector accounts for roughly 57% of the total electric energy efficiency achievable technical potential, followed by the commercial (42%) and industrial (2%) sectors.

Figure 12. Electric 24-Year Achievable Technical Potential by Sector

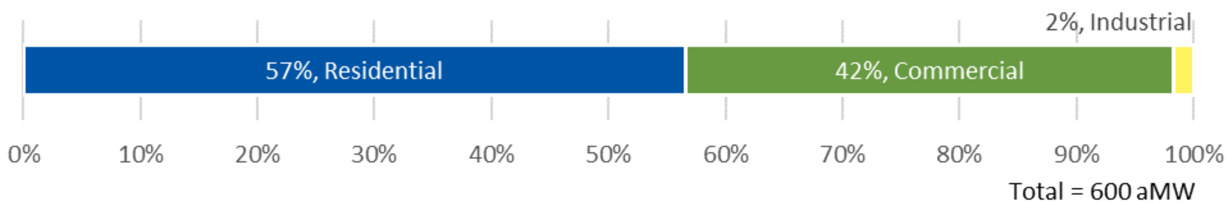


Figure 13 shows the relationship between each sector's cumulative (through 2045) electric energy efficiency achievable technical potential and the corresponding cost of conserved electricity.[6] For example, approximately 431 aMW of achievable technical potential exists, at a cost less than $150 per MWh.

6 In calculating levelized costs of conserved energy, non-energy benefits are treated as a negative cost. This means some measures will have a negative cost of conserved energy, although incremental upfront costs would occur.

Figure 13. Electric 24-Year Cumulative Energy Efficiency Supply Curve

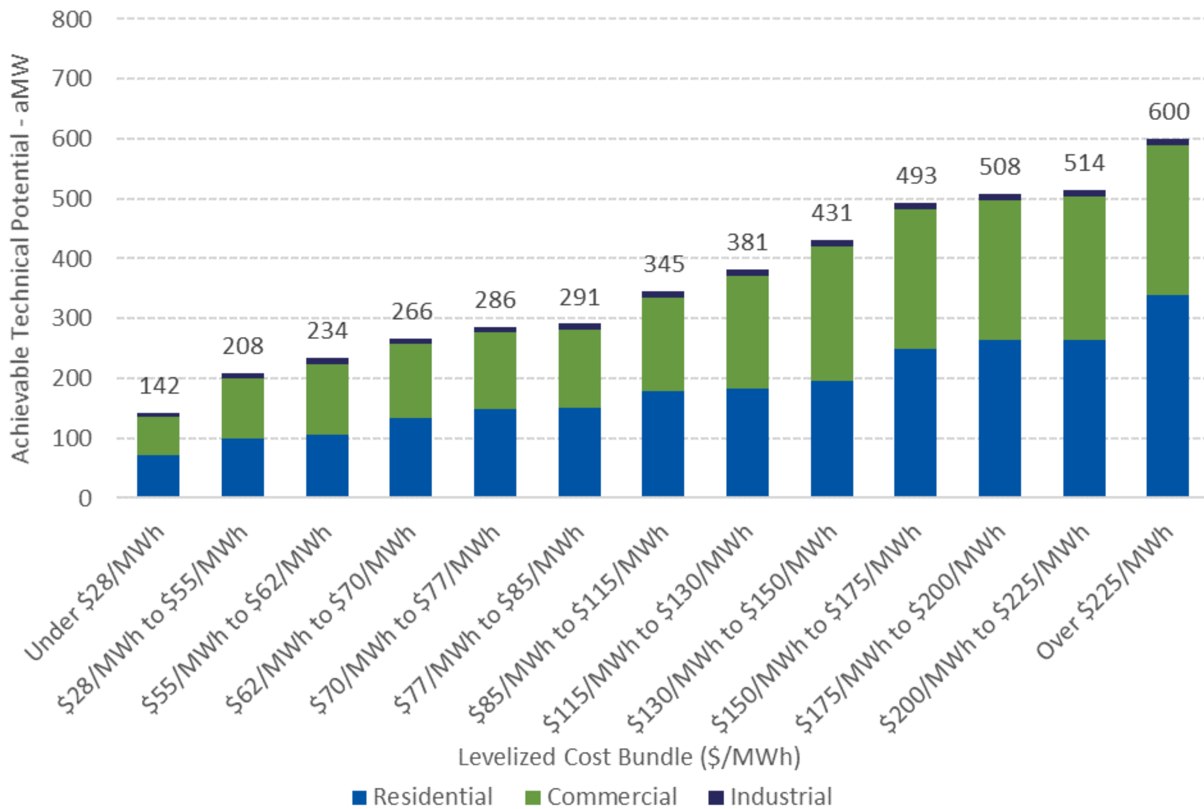
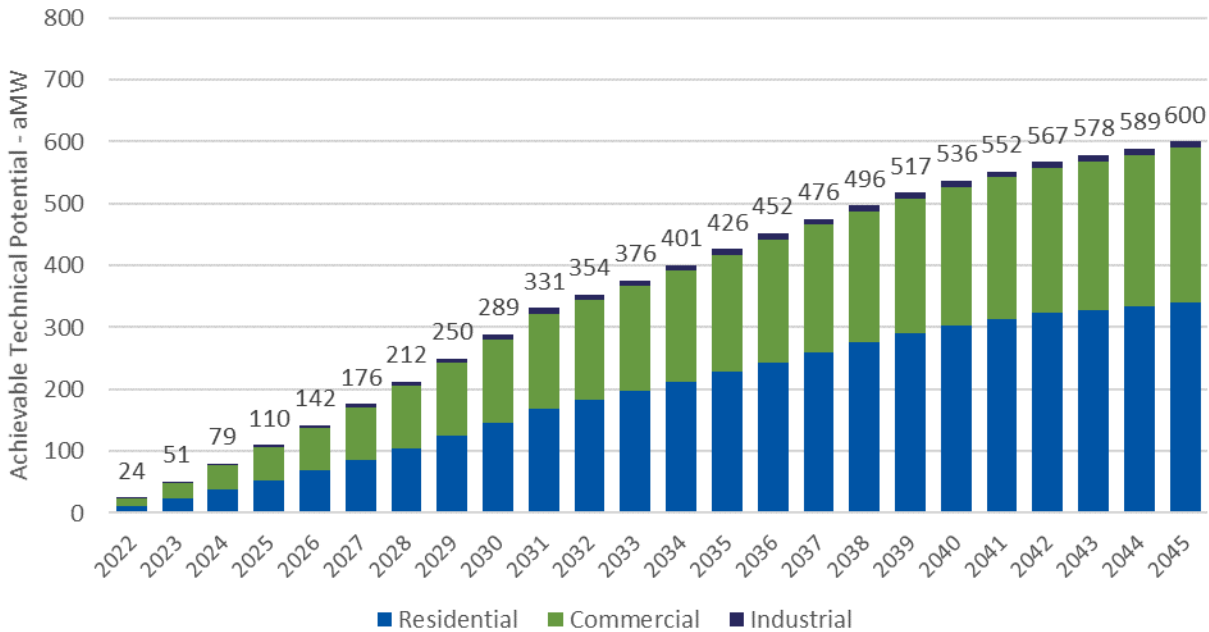


Figure 14 illustrates the cumulative potential annually available in each sector. The study assumes all discretionary resources will be acquired on a 10-year schedule between 2022 and 2031. The 10-year acceleration of discretionary resources will lead to the change in slope after 2031, at which point lost opportunity resources offer the only remaining potential.

Figure 14. Electric Energy Efficiency Potential Forecast



Summary of Resource Potential – Gas

Table 18 lists the 2041 forecasted baseline natural gas sales and potential by sector. The study results indicate roughly 174 million therms of achievable technical energy efficiency potential by 2041, the end of the 20-year planning horizon. Should all this potential prove cost-effective and realizable, it will amount approximately to a 15% reduction in 2041 forecasted retail sales.

Table 18. Natural Gas 20-Year Cumulative Energy Efficiency Potential

Sector	2041 Baseline Sales (MM Therms)	Achievable Technical Potential	
		MM Therms	Percentage of Baseline Sales
Residential	757	147	19%
Commercial	362	25	7%
Industrial	22	2	8%
Total	**1,141**	**174**	**15%**

Figure 15 shows the cumulative annual potential through 2041 available in each sector. The residential sector dominates natural gas potential with nearly 82% of total cumulative achievable technical potential, followed by commercial (17%) and industrial (1%).

Figure 15. Natural Gas 20-Year Achievable Technical Potential by Sector

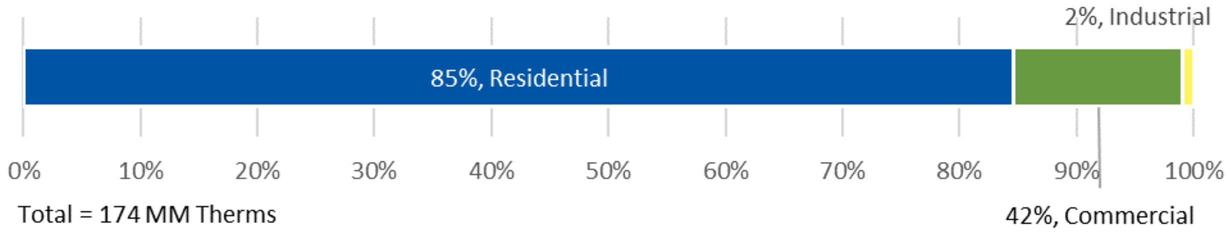


Figure 16 illustrates the relationship between identified natural gas achievable technical potential and its corresponding cost of conserved energy. For example, roughly 105 million therms of achievable technical potential will be available at a cost of less than $0.95 per therm.

Figure 16. Natural Gas 20-Year Cumulative Energy Efficiency Supply Curve

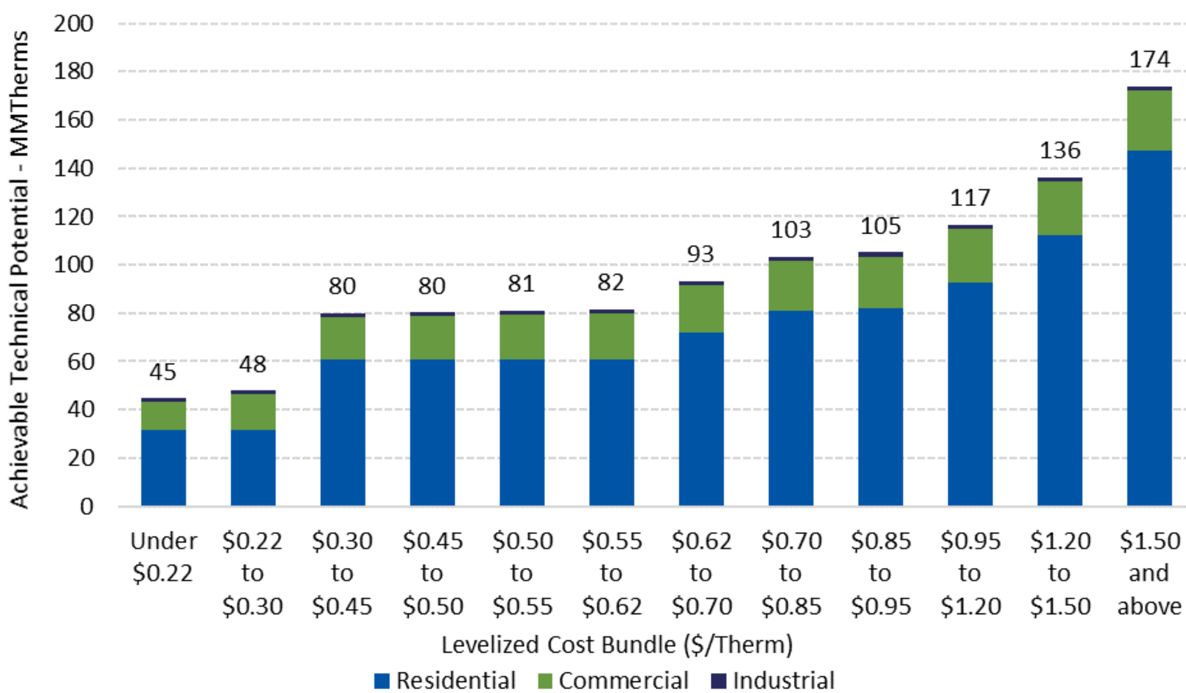
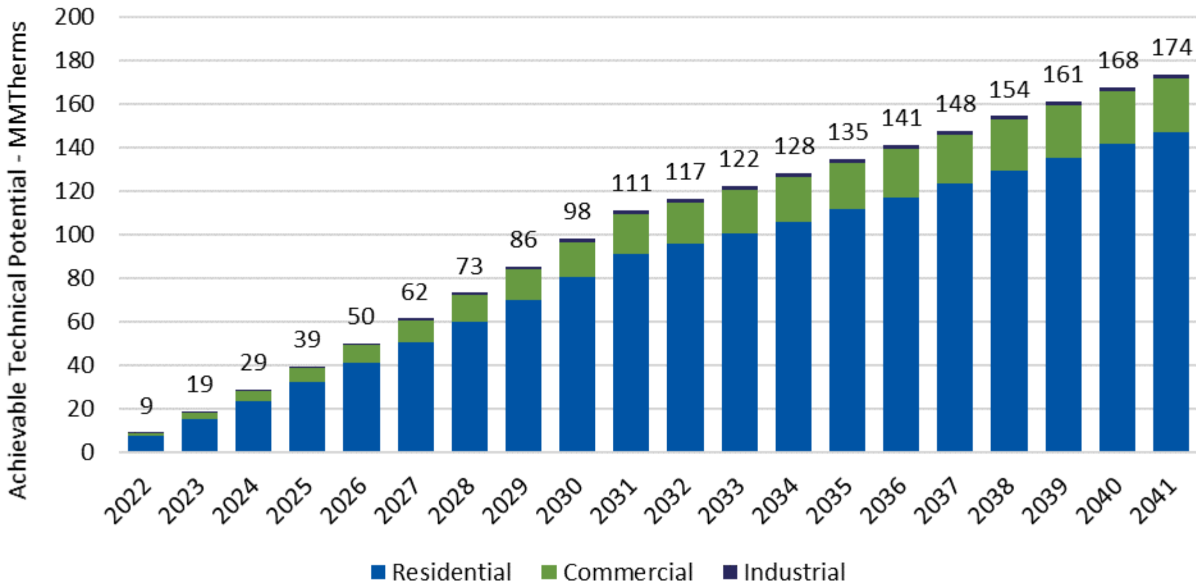


Figure 17 shows the cumulative potential available annually in each sector. As with electric potential, the study assumes all achievable discretionary opportunities will be acquired over the first 10 years of the study, from 2022 through 2031. Therefore, nearly 64% (111 MM therms) of the total natural gas achievable technical potential (174 MM therms) is achieved in the first ten years.

Figure 17. Natural Gas Energy Efficiency Potential Forecast



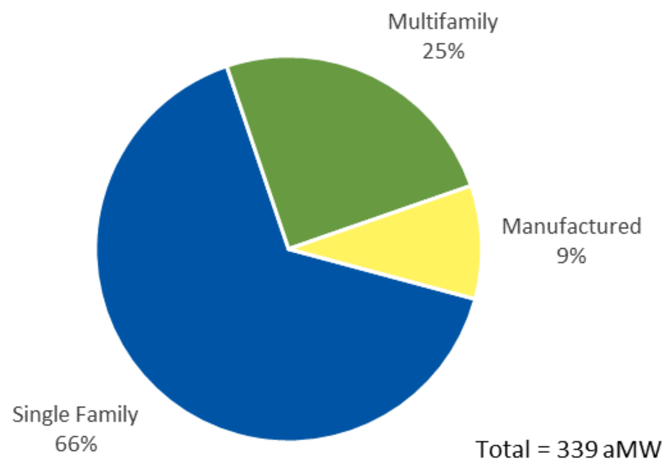
Detailed Resource Potential – Electric

Residential Sector – Electric

By 2045, residential customers in PSE's service territory will likely account for approximately 56% of forecasted electric retail sales. The single-family, manufactured, and multifamily dwellings comprising this sector present a variety of potential savings sources, including equipment efficiency upgrades (e.g., heat pumps, refrigerators), improvements to building shells (e.g., insulation, windows, air sealing), and increases in domestic hot water efficiency (e.g., heat pump water heaters).

As shown in Figure 18., single-family homes represent 66% of the total achievable technical residential electric potential, followed by multifamily (25%) and manufactured homes (9%). Each home type's proportion of baseline sales is the primary driver of these results, but other factors such as heating fuel sources and equipment saturations play an important role in determining potential.

Figure 18. Residential Electric Achievable Potential by Segment



For example, a higher percentage of manufactured homes use electric heat than do other home types, which increases their relative share of the potential. However, manufactured homes also tend to be smaller than detached single-family homes, and they experience lower per-customer energy; therefore, the same measure may save less in a manufactured home than in a single-family home.

Space heating end uses represent the largest portion (42%) of achievable technical potential. Appliances and water heating each also represent 15% and 14% respectively of the total identified potential (Figure 19). Lighting, an end use with considerably higher amounts of energy efficiency potential in previous PSE studies, comprises only 1% of the total residential electric energy efficiency potential due to the updated Washington State standard (H.B. 1444) and greater penetration of screw-based LEDs in recent years. The total achievable technical potential for residential increases to 339 aMW over the study horizon (Figure 20).

Figure 19. Residential Electric Achievable Potential by End Use

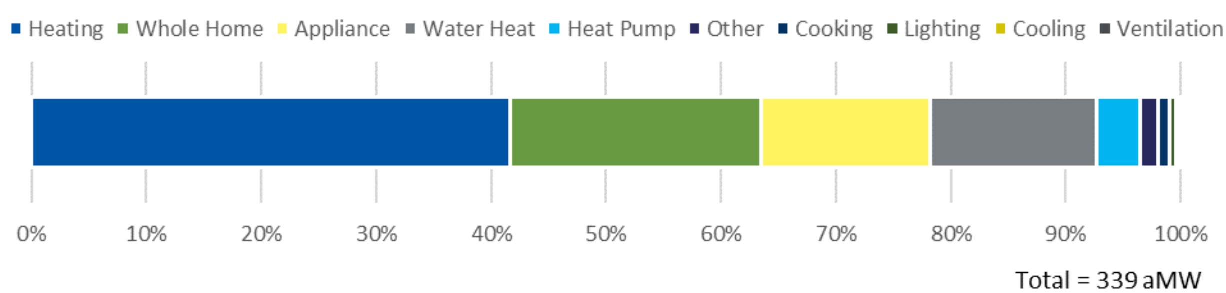


Figure 20. Residential Electric Achievable Potential Forecast

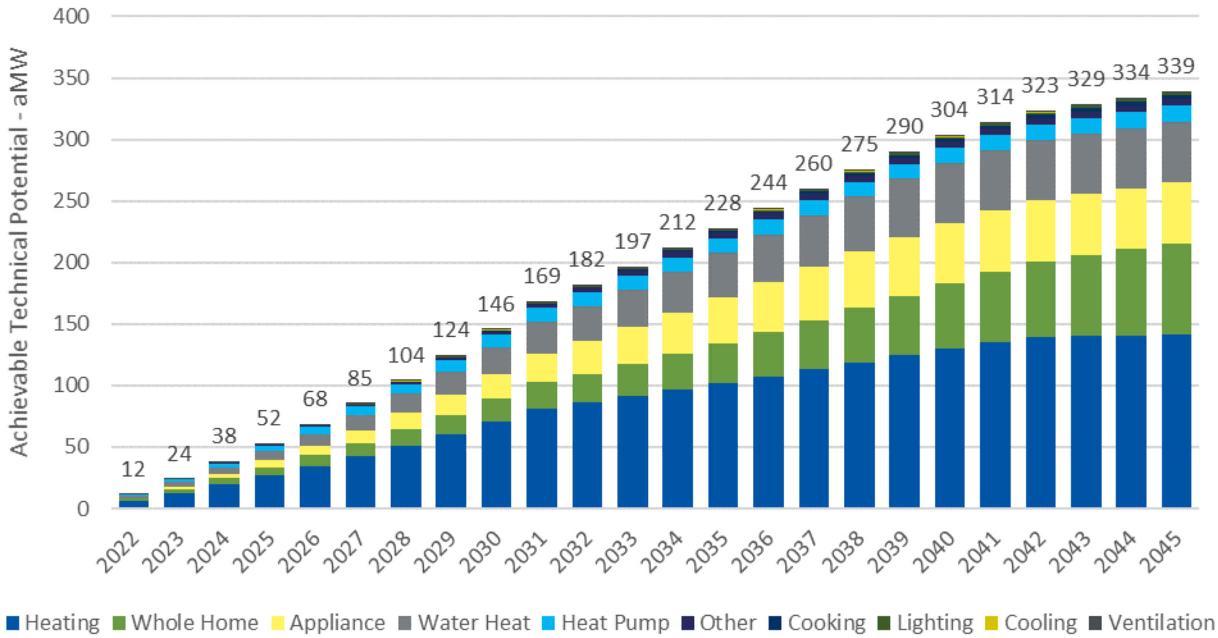


Table 19 lists the top 15 residential electric energy efficiency measures ranked in order of cumulative 24-year achievable technical potential. Combined, these 15 measures account for roughly 294 aMW, or approximately 87% of the total residential electric achievable technical potential. Various ductless heat pumps applications represent the measure group with the highest energy savings and eight of the top 15 measures reduce electric heating loads. These measures include equipment measures (i.e., ductless heat pumps and air-source heat pumps) and retrofit measures (i.e., windows, web-enabled thermostats, infiltration reduction, duct sealing, and wall insulation).

Table 19. Top Residential Electric Measures

Measure Name	Cumulative 10-Year Achievable Technical Potential (aMW)	Cumulative 24-Year Achievable Technical Potential (aMW)
Ductless Heat Pump	16.3	58.0
Whole Home	5.2	57.7
Heat Pump Water Heater	11.2	34.5
Window	26.3	26.3
Clothes Dryer	8.2	17.0
Home Energy Report	16.6	16.6
Heat Pump	4.9	17.7
Clothes Washer	5.9	14.2
Refrigerator	5.1	12.7
Thermostat	9.5	9.5
Solar Water Heater	3.9	3.9
Ground Source Heat Pump	0.7	8.1
Duct Sealing and Insulation	5.4	5.4
Wall Insulation	7.2	7.2
Duct Sealing	4.9	4.9

Residential Low Income – Electric

In addition to estimating potential for each residential housing segment, Cadmus also estimated potential for low income customers within PSE's electric service territory. Our team derived estimates of low income customers using income and housing sector variables from PSE's 2017 RCS. Based on PSE qualifying monthly income limit from PSE's Weatherization Assistance program. Varies by number of household occupants and 2016 annual household income (before taxes) from PSE's 2017 RCS. Table 20 provides the percent each residential sector's low income customers.

Table 20. PSE Low Income Customers - Electric Service

Segment	Electric Low Income Customers as a Percent of Total Electric Housing Segment Customers
Single Family	15.4%
Multifamily	24.4%
Manufactured	35.6%

Cadmus derived unit energy savings estimates specifically for low income customers using low income specific measures from PSE's business cases. Low income customer specific measures included the following:

- Weatherization. Attic, floor, and wall insulation, whole-home ventilation, and air/duct sealing
- Water heating. Tier 3 heat pump water heaters and low-flow showerheads and aerators
- HVAC equipment. Ductless heat pumps and air source heat pumps
- Smart thermostats, refrigerator replacements, and mobile home replacements

The study also apportioned savings from non-low income specific measures to low income customers for other measures, including:

- clothes dryers and clothes washers
- advanced power strips
- home energy reports
- refrigerator/freezer recycling
- freezers
- ovens and microwaves

Table 21 shows the cumulative 10-year (through 2031) and 24-year (through 2045) achievable technical potential for PSE's low income customers by housing segment.

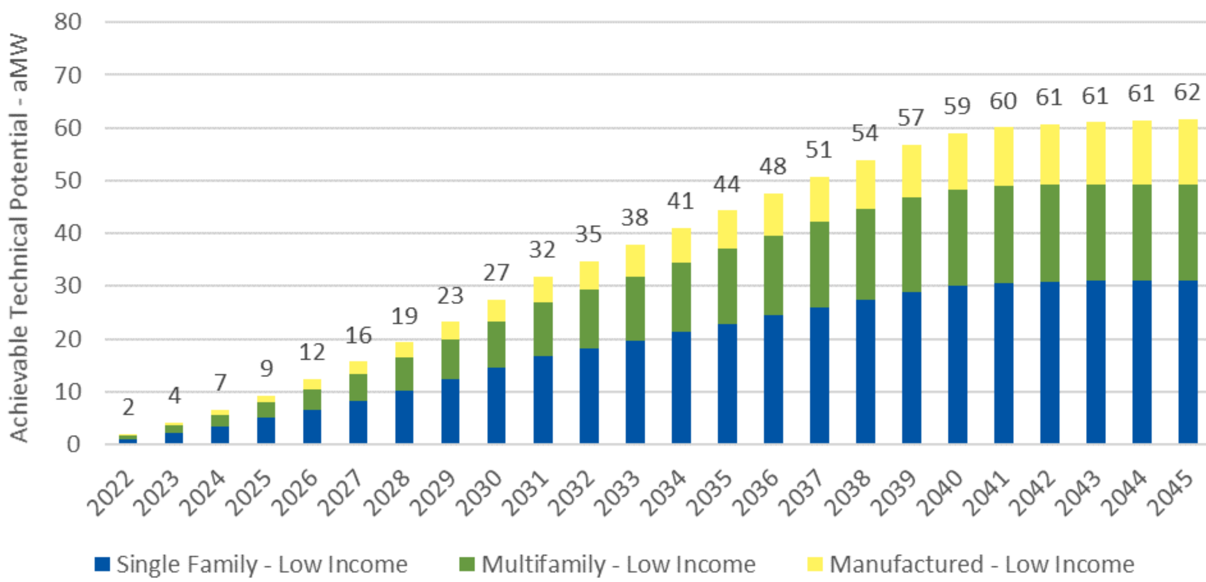
Table 21. Residential Low Income Customer Potential - Electric

Segment	Cumulative 10-Year Achievable Technical Potential (aMW)	Cumulative 24-Year Achievable Technical Potential (aMW)
Single Family - Low Income	16.8	31.0
Multifamily - Low Income	10.2	18.2

Segment	Cumulative 10-Year Achievable Technical Potential (aMW)	Cumulative 24-Year Achievable Technical Potential (aMW)
Manufactured - Low Income	4.8	12.3
Total	**31.8**	**61.6**

Figure 21 provides the cumulative residential low income electric achievable potential forecast by housing segment. The potentials shown in Figure 20 include the low income customer potential shown in Figure 21.

Figure 21. Residential Low Income Electric Achievable Potential Forecast

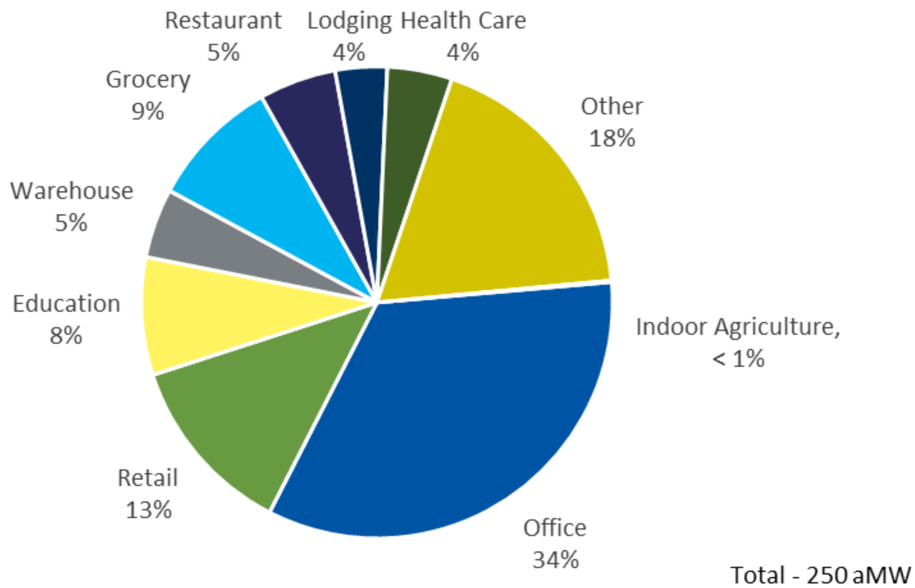


Commercial Sector - Electric

Based on the energy efficiency measure resources used in this assessment, electric energy efficiency achievable technical potential in the commercial sector will likely be 250 aMW over 24 years, which is approximately a 19% reduction in forecasted 2045 commercial sales.

As shown in Figure 22, the Office and Other segments represent 34% and 19%, respectively, of the total commercial achievable technical potential; no other single commercial segment represents more than 12% of commercial achievable technical potential. The Other segment includes customers that do not fit into any of the other categories and customers with insufficient information for classification.

Figure 22. Commercial Electric Achievable Potential by Segment



As shown in Figure 23, lighting efficiency improvements represent the largest portion for achievable technical end use savings potential in the commercial sector (39%), followed by other (29%), and cooling (8%) end uses. Lighting potential includes bringing existing buildings to code and exceeding code in new and existing structures. Figure 24 presents the cumulative electric commercial end use achievable technical by end use.

Figure 23. Commercial Electric Achievable Potential by End Use

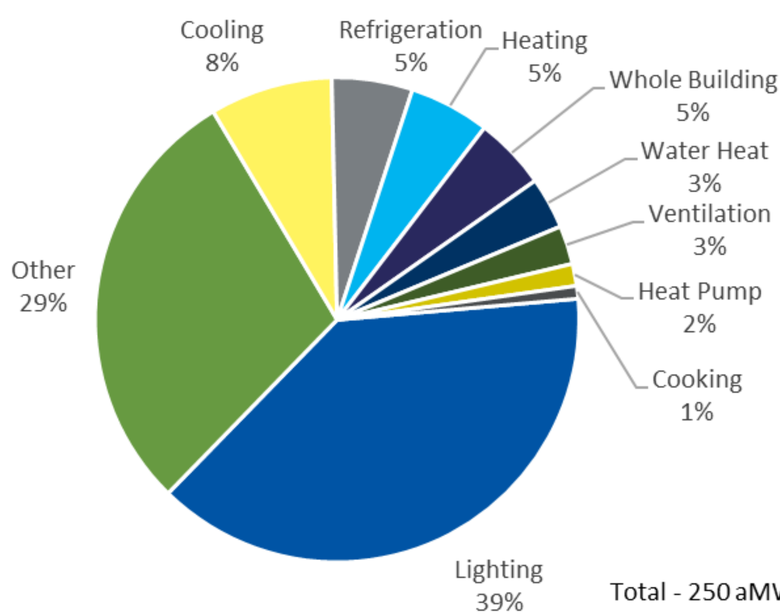


Figure 24. Commercial Electric Achievable Potential Forecast

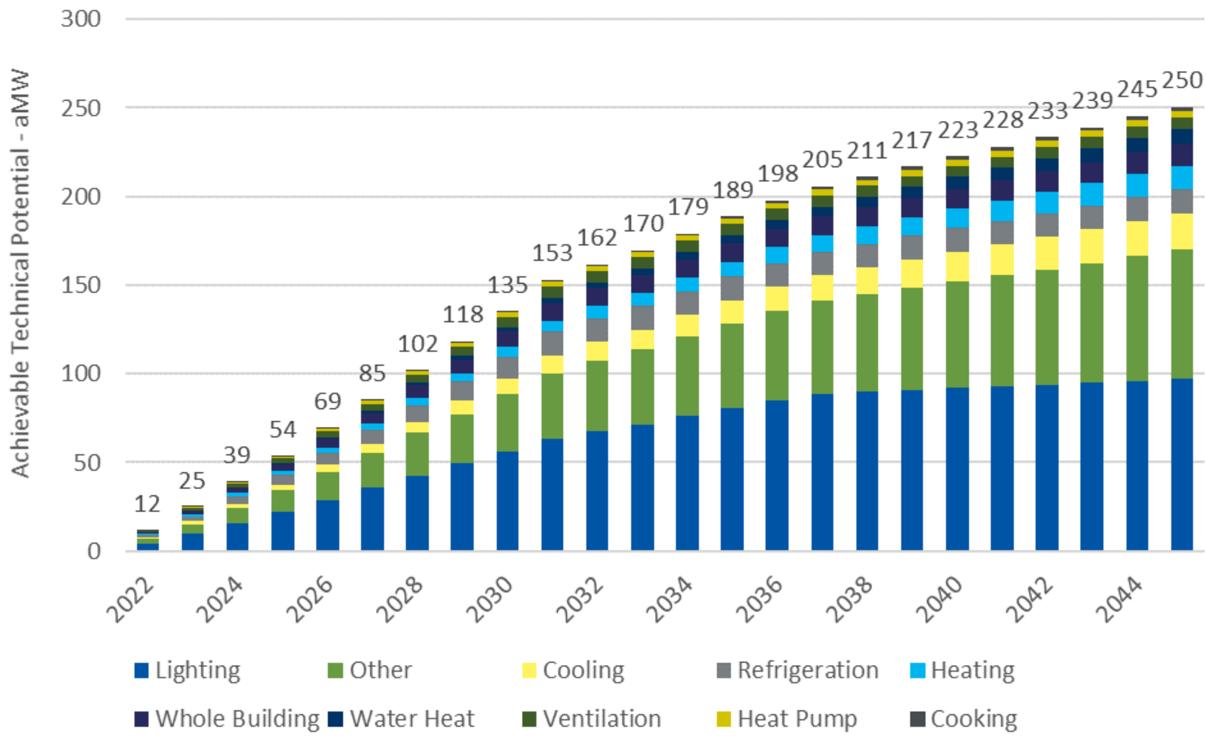


Table 22 lists the top 15 commercial electric energy efficiency measures ranked in order of cumulative 24-year achievable technical potential. Combined, these 15 measures account for 177 aMW, or approximately 71% of the total electric commercial achievable technical potential. Commercial LED lighting measures, including linear fixtures, high bay, and "other" applications including some measures falling outside of the top 15 commercial measures, account for approximately 97 aMW, or 39% of total commercial electric energy efficiency potential.

Table 22. Top Commercial Electric Measures

Measure Name	Cumulative 10-Year Achievable Technical Potential (aMW)	Cumulative 24-Year Achievable Technical Potential (aMW)
LED Panel	27.5	44.8
Variable Speed Efficient Motor	11.6	40.4
Linear LED	7.7	18.4
Variable Refrigerant Flow	4.4	10.6
Wastewater	9.6	9.6
High Bay LED Panel	5.2	8.1
Circulator Pump (bronze or stainless, learning-run hours)	7.1	7.1
Refrigeration – Electrically Commutated Motor	6.7	6.7
Pool Heat Recovery	5.7	5.7
Showerhead	5.2	5.2
Commercial Strategic Energy Management	4.2	4.9
Parking Garage Lighting	4.5	4.5
LED Sign	4.5	4.5
Residential-type Advanced Heat Pump Water Heater EF2.8	1.0	4.3
LED Other	4.2	4.2

Industrial Sector – Electric

This study estimates technical and achievable technical energy efficiency potential for major end uses in 19 major industrial sectors Across all industries, achievable technical potential is approximately 10 aMW over the 24-year planning horizon, corresponding to an 8% reduction of forecasted 2045 industrial electric retail sales.

Figure 25 shows 24-year electric industrial achievable technical potential by segment. Miscellaneous manufacturing represents 29% of the total electric industrial achievable technical potential, followed by streetlighting (26%), food manufacturing (17%), and wood manufacturing (8%). No other industry represents more than 5% of industrial electric potential.

Figure 25. Industrial Electric Achievable Technical Potential Forecast

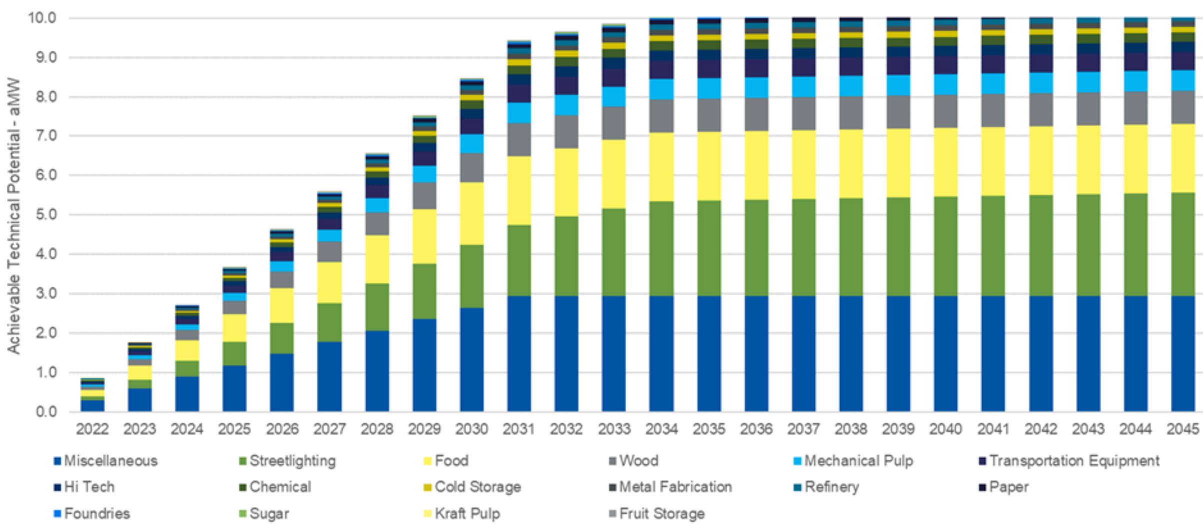


Table 23 presents electric cumulative 24-year achievable technical potential for the top 15 measures in the industrial sectors. Cadmus derived these measures from the Council's Seventh Power Plan and the top three measures combined—plant energy management, streetlighting, and energy project management—equal approximately 2.7 aMW of achievable technical potential, or roughly 27% of the industrial total.

Table 23. Top Industrial Electric Measures

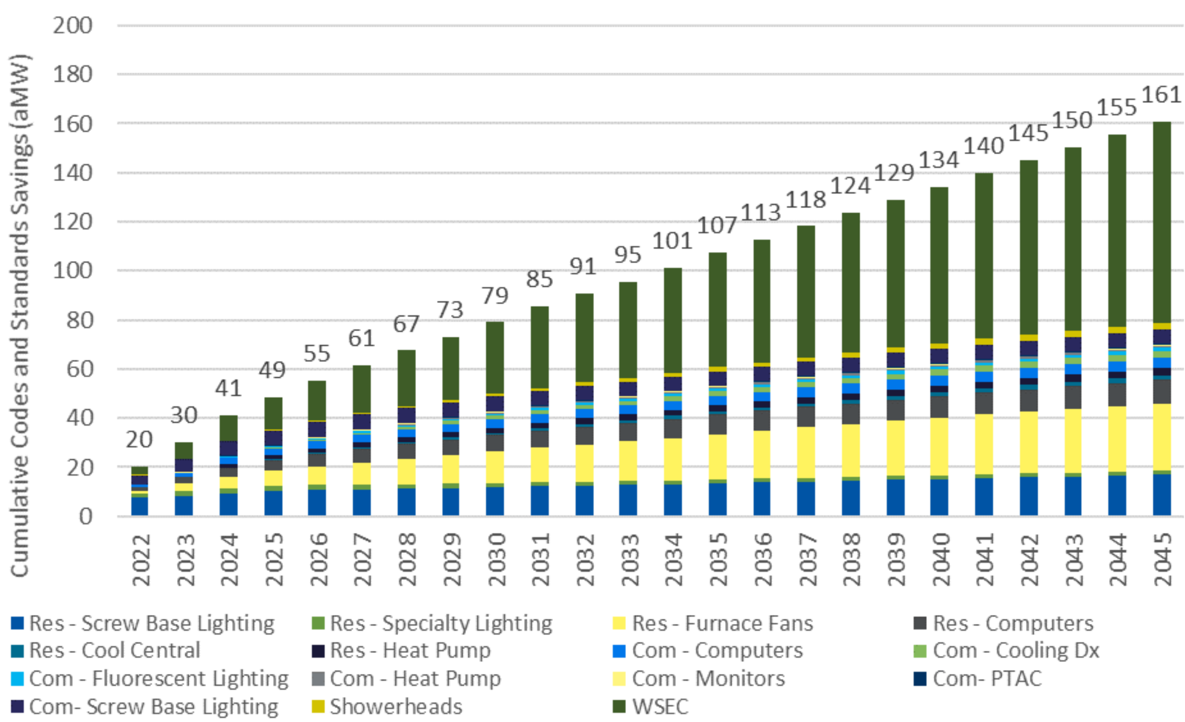
Reporting Group	Cumulative 10-Year Achievable Technical Potential (aMW)	Cumulative 24-Year Achievable Technical Potential (aMW)
Plant Energy Management	1.1	1.1
Streetlight - MH 400W - NR	0.7	0.9
Energy Project Management	0.7	0.7
Fan System Optimization	0.6	0.6
Integrated Plant Energy Management	0.6	0.6
Fan Equipment Upgrade	0.6	0.6
Pump System Optimization	0.5	0.5
Pump Equipment Upgrade	0.5	0.5

Reporting Group	Cumulative 10-Year Achievable Technical Potential (aMW)	Cumulative 24-Year Achievable Technical Potential (aMW)
Streetlight - HPS 250W - NR	0.3	0.4
Streetlight - HPS 100W - NR	0.3	0.4
Wood: Replace Pneumatic Conveyor	0.3	0.3
Clean Room: Change Filter Strategy	0.3	0.3
Material Handling VFD2	0.3	0.3
Streetlight - MH 200W - NR	0.2	0.2
Food: Cooling and Storage	0.2	0.2

Codes and Standards – Electric

Figure 26 presents naturally occurring savings in PSE's service area from Washington state energy codes and equipment standards and federal equipment standards. Overall, the Washington State Energy Code (WSEC) accounts for roughly two-thirds of total electric codes and standards savings, with approximately 82 aMW over the 24-year study horizon. Of these 82 aMW, the commercial WSEC accounts for roughly 35 aMW, whereas the residential WSEC accounts for approximately 47 aMW.

Figure 26. Electric Codes and Standards Potential Forecast



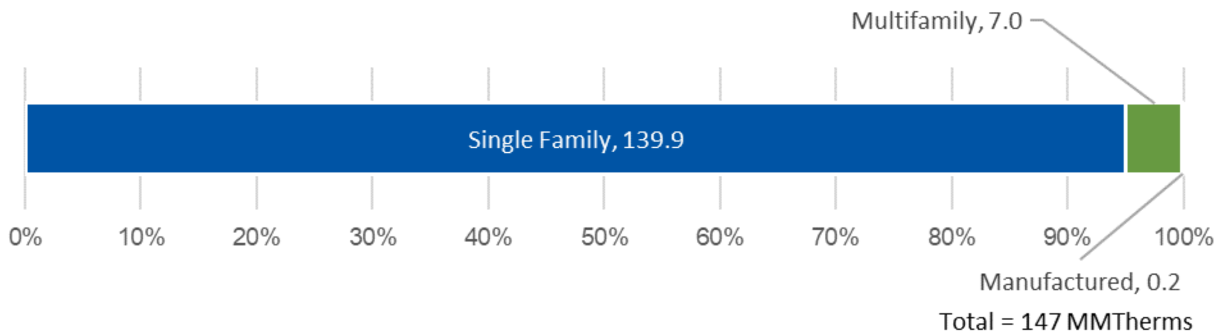
Detailed Resource Potential – Gas

Residential Sector - Gas

By 2041, residential customers will likely account for approximately 67% of PSE's natural gas sales. Unlike residential electricity consumption, there are relatively few natural gas-fired end uses (primarily space heating, water heating, and appliances including dryers and stove tops). Nevertheless, significant available energy savings opportunities remain. Based on the energy efficiency measures used in this assessment, achievable technical potential in the residential sector will likely provide about 147 million therms over 20 years, corresponding to a 19% reduction of forecasted 2041 retail sales.

Single-family homes account for 95% of the identified achievable technical potential, as Figure 27 shows. Less than 5% of total achievable technical potential occurs in multifamily and manufactured residences due to a lack of gas connections.

Figure 27. Residential Natural Gas Achievable Potential by Segment



As shown in Figure 28, space heating (59%), whole home measure (21%), and water heating (18%) end uses account for over 98% of the identified achievable technical potential, which combines high-efficiency equipment (such as condensing furnaces and water heaters) and retrofits (such as shell measures, smart thermostats, and duct and pipe insulation). Figure 29 shows the cumulative natural gas achievable technical potential by residential end use.

Figure 28. Residential Natural Gas Achievable Potential by End Use

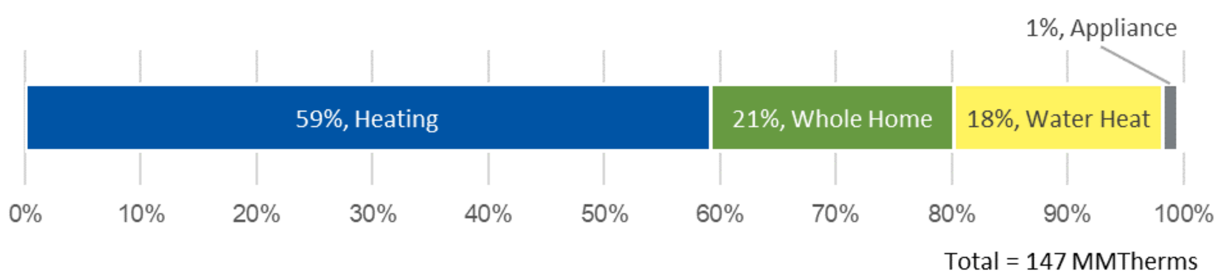


Figure 29. Residential Natural Gas Achievable Potential Forecast

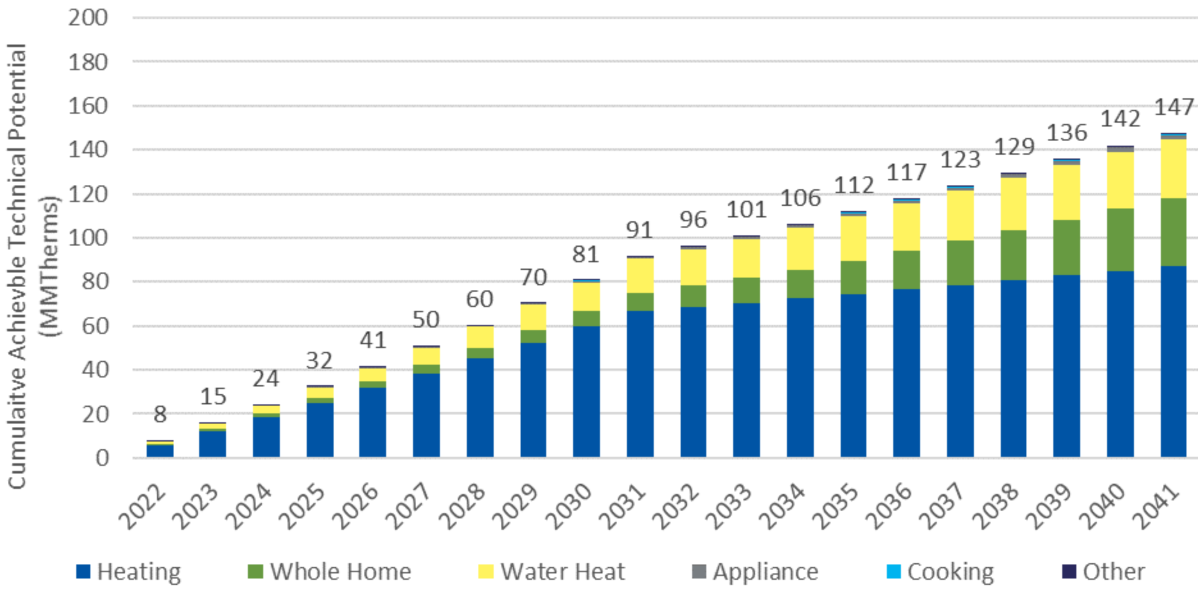


Table 24 shows the top 15 residential natural gas energy efficiency measures ranked in order of cumulative 20-year achievable technical potential. Combined, these 15 measures account for 136 million therms, or approximately 93% of the total residential achievable technical potential.

Table 24. Top Residential Gas Measures

Measure Name	Cumulative 10-Year Achievable Technical Potential (MM Therms)	Cumulative 20-Year Achievable Technical Potential (MM Therms)
Furnace	12.8	32.1
Whole Home	3.3	25.7
Water Heater	5.1	16.3
Thermostat	11.2	11.2
Window	10.5	10.5
Wall Insulation	7.3	7.3
Duct Sealing and Insulation	7.1	7.1
Duct Sealing	5.4	5.4
Home Energy Report	5.2	5.2
Thermostatic Restrictor Valve	3.1	3.1
Whole House Sealing	3.0	3.0
Floor Insulation	2.6	2.6
Showerhead	2.4	2.4
Aerators	2.3	2.3
Solar Water Heater	2.3	2.3

Residential Low Income – Gas

In addition to estimating potential for each residential housing segment, Cadmus also estimated potential for low income customers within PSE's natural gas service territory. Our team derived estimates of low income customers using income and housing sector variables from PSE's 2017 RCS. Based on PSE qualifying monthly income limit from PSE's Weatherization Assistance program. Varies by number of household occupants and 2016 annual household income (before taxes) from PSE's 2017 RCS. Table 25 provides the percent each residential sector's low income customers.

Table 25. PSE Low Income Customers - Gas Service

Segment	Electric Low Income Customers as a Percent of Total Electric Housing Segment Customers
Single Family	9.1%
Multifamily	8.3%
Manufactured	11.3%

Cadmus derived unit energy savings estimates specifically for low income customers using low income specific measures from PSE's business cases. Low income customer specific measures included the following:

- **Weatherization:** Attic, floor, and wall insulation, and air/duct sealing
- **Water heating**: ENERGY STAR tankless and storage water heaters, water heater pipe insulation, and low-flow showerheads and aerators
- **HVAC equipment:** Furnace replacements
- **Additional measures:** Smart thermostats and integrated space and water heating

The study also apportioned savings from non-low income specific measures to low income customers for other measures, including:

- clothes dryers and washers
- boilers
- home energy reports
- refrigerator/freezer recycling
- convection ovens

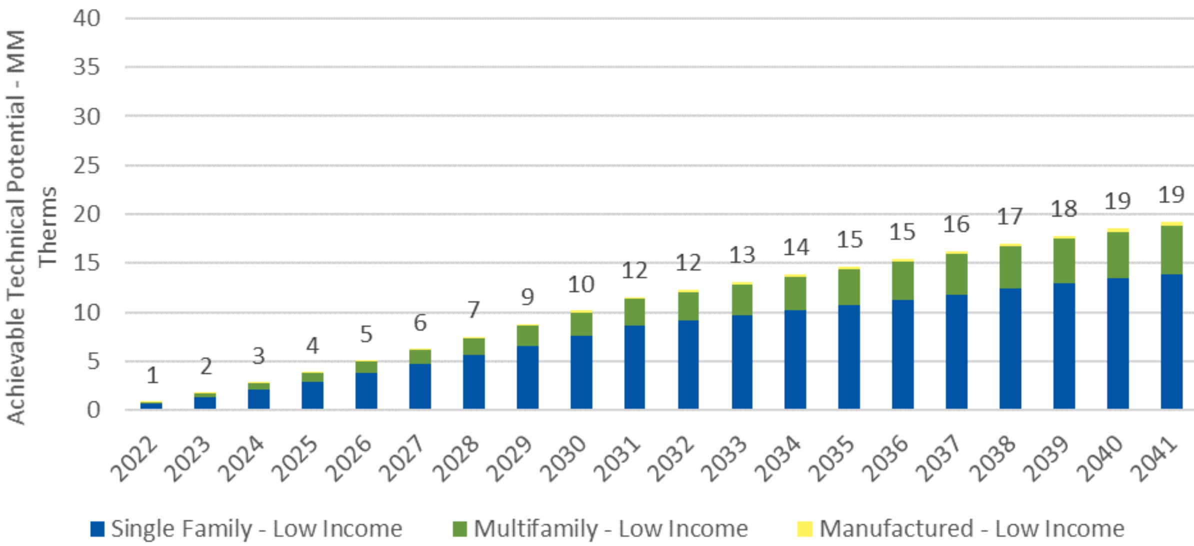
Table 26 shows the cumulative 10-year (through 2031) and 20-year (through 2041) natural gas achievable technical potential for PSE's low income customers by housing segment.

Table 26. Residential Low Income Customer Potential - Gas

Segment	Cumulative 10-Year Achievable Technical Potential (MM Therms)	Cumulative 20-Year Achievable Technical Potential (MM Therms)
Single Family - Low Income	8.6	13.8
Multifamily - Low Income	2.7	5.0
Manufactured - Low Income	0.2	0.4
Total	**11.6**	**19.2**

Figure 30 provides the cumulative residential low income natural gas potential forecast by housing segment. The potentials in Figure 29 include the low income customer potential shown in Figure 30.

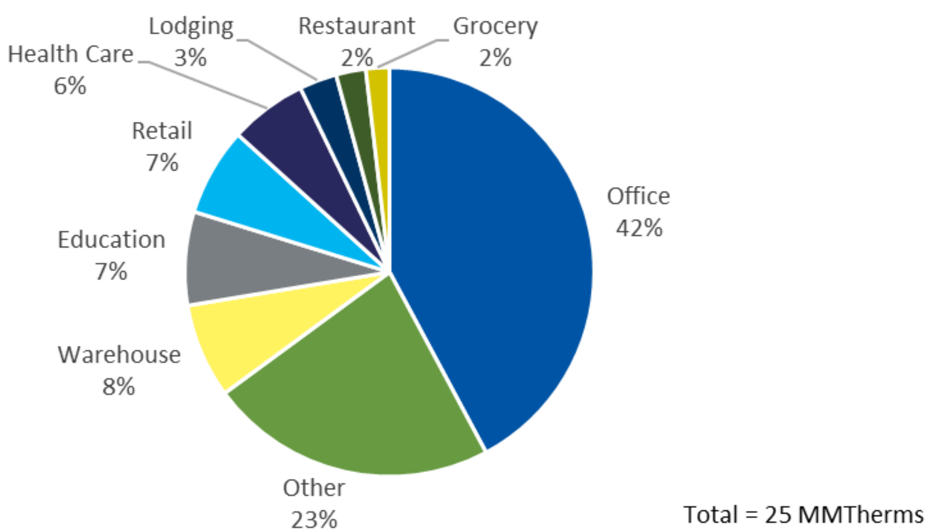
Figure 30. Residential Low Income Customer Potential - Gas



Commercial Sector – Gas

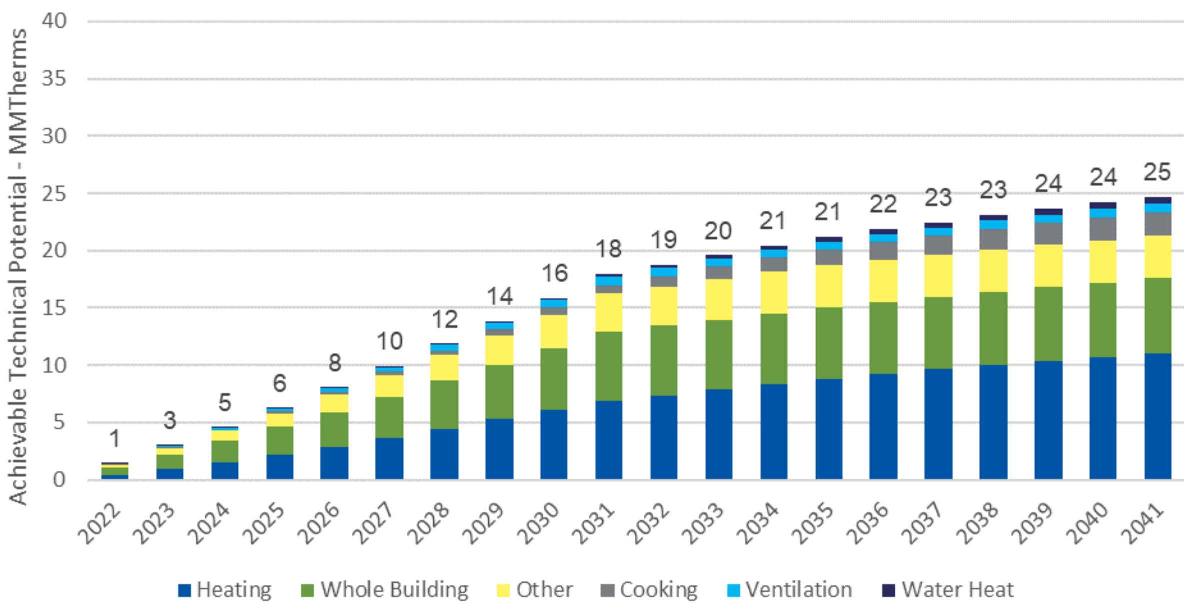
According to the resources used in this assessment, natural gas achievable technical potential in the commercial sector will likely be 25 million therms over 20 years, a 7% reduction in forecasted 2041 commercial retail sales. As shown in Figure 31., for natural gas customers, office buildings represent the largest portion of potential (42%), followed by other commercial facilities (23%), and warehouses (8%).

Figure 31. Commercial Gas Achievable Potential by Segment



As in the residential sector, far fewer gas-fired end uses exist compared to electric end uses. Space heating accounts for 44% of the identified commercial natural gas potential. The remaining potential is comprised mainly of whole building measures (27%),other end uses (15%), and water heating (11%), with the remaining potential coming from cooking (8%), and ventilation (3%), as shown in Figure 32.

Figure 33. Commercial Gas Achievable Potential Forecast



provides the commercial natural gas annual cumulative achievable technical potential by end use.

Figure 32. Commercial Gas Achievable Potential by End Use

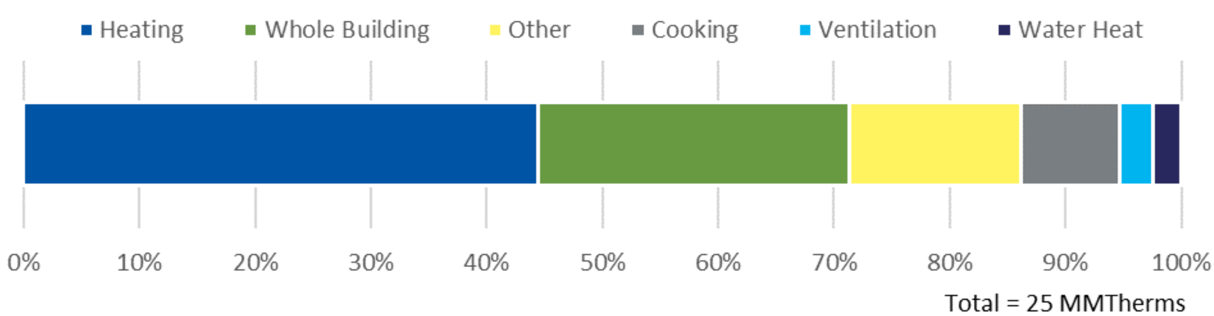


Figure 33. Commercial Gas Achievable Potential Forecast

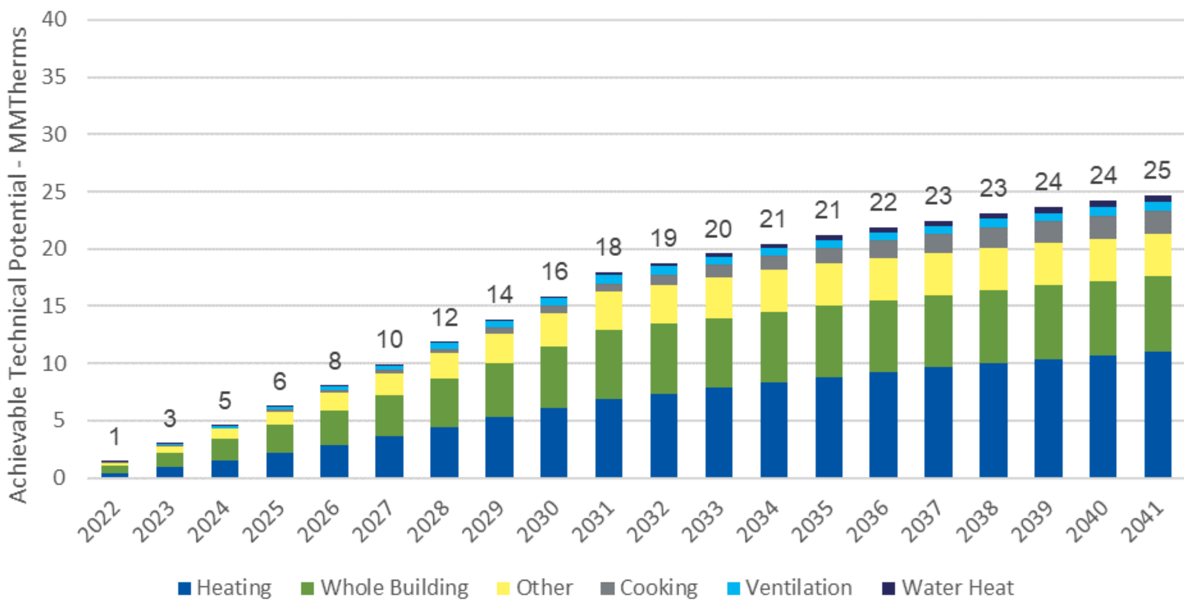


Table 27 shows the top 15 commercial natural gas energy efficiency measures ranked in order of cumulative 20-year achievable technical potential. Combined, these 15 measures account for approximately 18 million therms, or about 71% of the total natural gas commercial achievable technical potential.

Table 27. Top Commercial Gas Measures

Measure Name	Cumulative 10-Year Achievable Technical Potential (MM Therms)	Cumulative 20-Year Achievable Technical Potential (MM Therms)
Gas RTU Supply Fan VFD and Controller	3.0	3.0
Furnace LT 225 kBtuh High AFUE 92% Non-Weatherized	1.0	1.8
Furnace LT 225 kBtuh Premium AFUE 94% Non-Weatherized	0.8	1.9
Ozone Laundry	1.5	1.5
Pool Heat Recovery	2.4	2.4
DDC Energy Management	1.5	1.7
Commissioning Retro	1.5	1.5
Boiler 300 to 2500 kBtuh AFUE 95%	0.4	1.1
Clothes Washer	0.5	0.9
Boiler 300 to 2500 kBtuh AFUE 85%	0.3	0.8
DCV Kitchen	0.6	0.6
Oven Double Rack	0.2	0.6
Gas Water Heater 94% Efficient	0.2	0.5
Boiler 300 to 2500 kBtuh AFUE 79%	0.2	0.6
Convection Oven	0.2	0.5

Industrial Sector – Gas

Because electricity powers most industrial processes and end uses, the industrial sector represents a small portion of natural gas baseline sales and potential.

Across all industries, achievable technical potential totals approximately 1.7 million therms over 20 years. Although this represents 8% of forecasted 2041 industrial sales, it accounts for only 0.9% of the achievable technical potential across the three sectors. As shown in Figure 34, substantial achievable technical potential occurs in miscellaneous manufacturing (44%), transportation (17%), mechanical pulp (15%), and food production (10%).

Figure 34. Industrial Gas Achievable Technical Potential Forecast

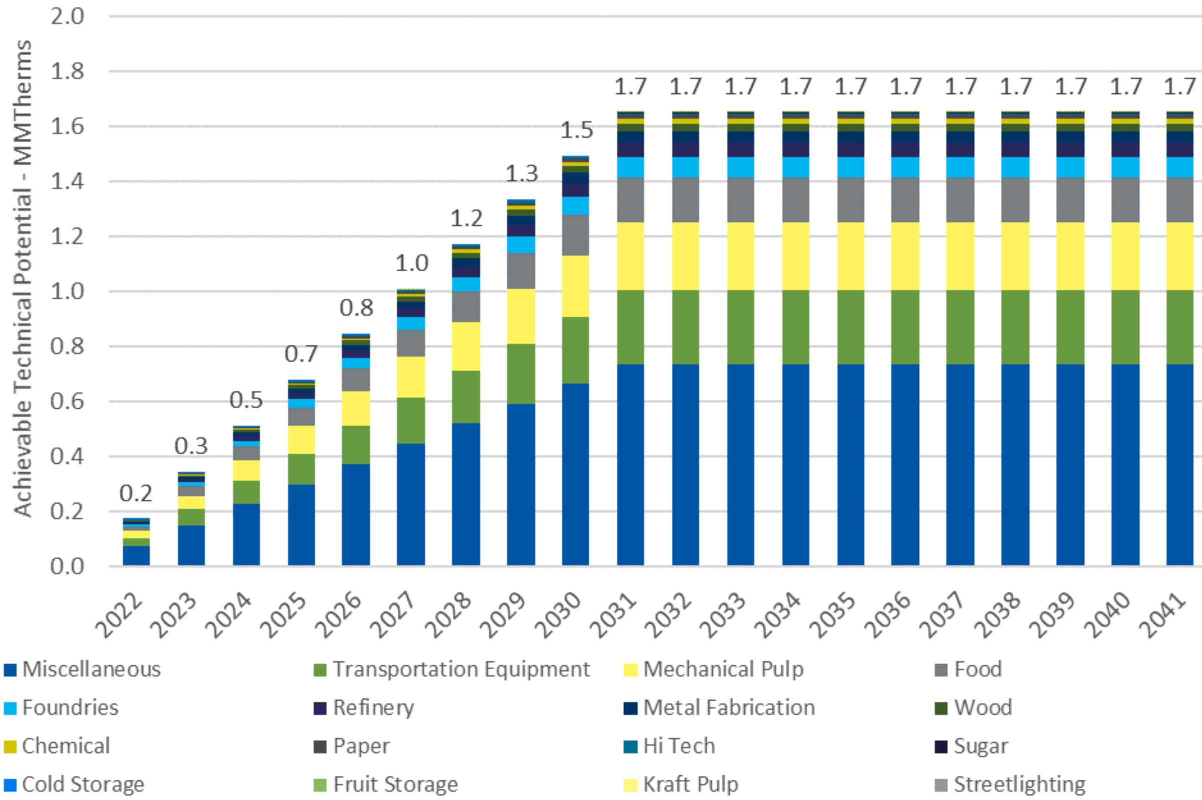


Table 28 lists the top 15 industrial natural gas energy efficiency measures ranked in order of cumulative 20-year achievable technical potential. Combined, these 15 measures account for approximately 1.4 million therms, or about 87% of the total natural gas industrial achievable technical potential.

Table 28. Top Industrial Gas Measures

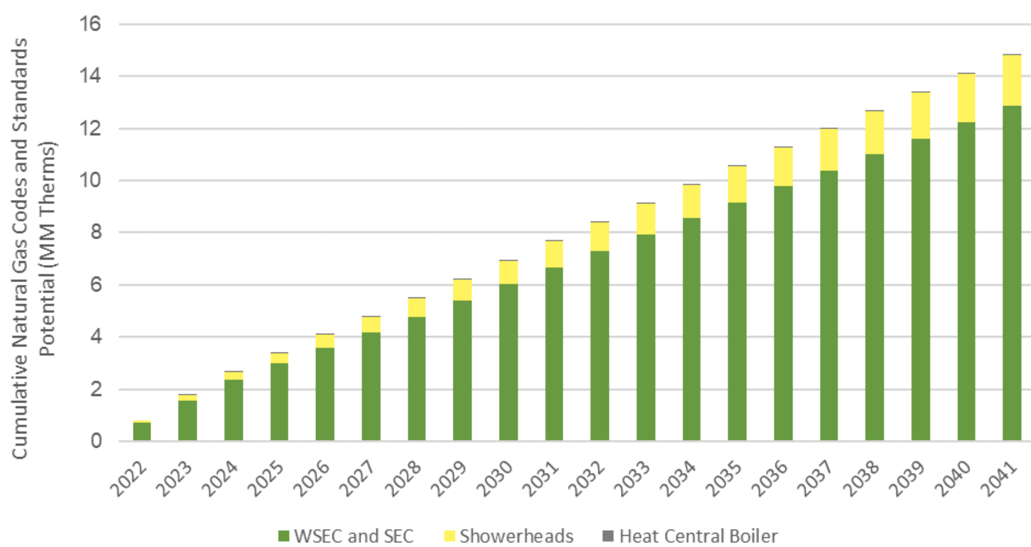
Measure Name	Cumulative 2031 Achievable Technical Potential (Therms)	Cumulative 2041 Achievable Technical Potential (Therms)
Equipment Upgrade - Replace Existing HVAC Unit with High Efficiency Model	196,537	196,537
Process Improvements to Reduce Energy Requirements	174,386	174,386
Improve Combustion Control Capability and Air Flow	138,408	138,408
HVAC Equipment Scheduling Improvements - HVAC Controls, Timers or Thermostats	114,484	114,484
Install or Repair Insulation on Condensate Lines and Optimize Condensate	110,464	110,464
Optimize Ventilation System	93,553	93,553
Waste Heat from Hot Flue Gases to Preheat	86,669	86,669
Heat Recovery and Waste Heat for Process	75,334	75,334

Measure Name	Cumulative 2031 Achievable Technical Potential (Therms)	Cumulative 2041 Achievable Technical Potential (Therms)
Equipment Upgrade - Boiler Replacement	71,916	71,916
Optimize Heating System to Improve Burner Efficiency, Reduce Energy Requirements and Heat Treatment Process	71,900	71,900
Building Envelope Infiltration Improvements	64,671	64,671
Building Envelope Insulation and Window/Door Improvements	62,980	62,980
Thermal Systems Reduce Infiltration; Isolate Hot or Cold Equipment	59,471	59,471
Replace Steam Traps	58,755	58,755
Repair and Eliminate Steam Leaks	53,159	53,159

Codes and Standards – Gas

Figure 35 presents naturally occurring natural gas savings in PSE's service area from Washington State energy codes and federal equipment standards. Overall, the WSEC represents most natural gas codes and standards savings, with approximately 13 million therms over the 20-year study horizon. The commercial and residential WSEC account for 6 million and 7 million therms, respectively.

Figure 35. Natural Gas Codes and Standards Forecast



Combined Heat and Power

CHP Technical Potential Approach

CHP technical potential represents total electric generation, if installing all resources in all technically feasible applications. Technical potential assumes every end-use customer in PSE's service territory—if meeting CHP energy demand requirements—installs a system. This largely unrealizable potential should be considered a theoretical construct.

Cadmus assessed applicable, technical CHP potential for the commercial and industrial sectors in PSE's service area. Traditionally, CHP systems have been installed in hospitals, schools, universities, military bases, and manufacturing facilities. They can be used, however, across nearly all commercial and industrial market segments with average monthly energy loads greater than approximately 30 kW, which encompasses nearly all commercial and industrial facilities.

CHP can be broadly divided into two subcategories, based on the fuels used:

- Nonrenewable CHP, typically using natural gas
- Renewable systems using biologically derived fuel (biomass or biogas)

Cadmus analyzed the following **non-renewable, natural gas-consuming CHP systems**:

- Reciprocating engines, which cover a wide range of sizes
- Microturbines, which represent newer technologies with higher capital costs
- Gas turbines, which typically are large systems

Cadmus analyzed the following **renewable-fueled systems:**

- ***Industrial biomass systems*** are used in industries for which site-generated waste products can be combusted in place of natural gas or other fuels (e.g., lumber, pulp, and paper manufacturing). This analysis assumed the type of combustion processes in a CHP system (generally steam turbines) to generate electricity on site. An industrial biomass system generally operates on a large scale, with a capacity greater than 1 MW.
- ***Anaerobic digesters*** create methane gas (i.e., biogas fuel) by breaking down liquid or solid biological waste. Anaerobic digesters can be coupled with a variety of generators, including reciprocating engines and microturbines, and typically are installed at landfills, wastewater treatment facilities, and livestock farms and feedlots.

Cadmus calculated technical potential to determine the number of eligible customers by segment and size (i.e., demand) in PSE's service area then applied assumptions about CHP or biomass/biogas system sizes and performance. Table 29 lists the sources Cadmus referenced for each input. Recent studies completed for the California Self-Generation Incentive Program (SGIP) have the largest sample sizes (as it is the longest-running CHP program in the nation). Cadmus also reviewed studies from other regions and, where possible, benchmarked SGIP data with other studies.

Table 29. Data Sources for CHP Technical Potential

Inputs	Source	Website Link (if available)
Capacity Factor, Performance Degradation, Heat Recovery Rate	Itron. *SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report].* Table 4-4: Summary of Operating Characteristics of SGIP Technologies. pp. 4-13. October 2015.	http://www.cpuc.ca.gov/General.aspx?id=7890
Measure Life	Marin, W., et al. *Understanding Early Retirement of Combined Heat and Power (CHP) Systems: Going Beyond First Year Impacts Evaluations*. 2015 International Energy Program Evaluation Conference, Long Beach.	https://www.iepec.org/wp-content/uploads/2015/papers/178.pdf
System Sizes	*Self-Generation Incentive Program Weekly Statewide Report.*	https://www.selfgenca.com/documents/reports/statewide_projects
Number of Customers, Projected Sector Growth, Line Losses	PSE data	N/A
Existing CHP Capacity	U.S. Department of Energy. "Combined Heat and Power Installation Database."	https://doe.icfwebservices.com/chpdb/
Customer Size Data	PSE data	N/A

CHP Achievable Potential Approach

Cadmus applied an achievable penetration rate to technical potential estimates to determine the market potential or likely future installations. Determining this rate involved reviewing a range of market penetration estimates using benchmarked estimates from recent studies, as listed in Table 30. We examined historic trends in installed capacity for several states (including Washington), technology, and fuel type using the U.S. Department of Energy (DOE) CHP Installation Database and reviewing states' favorability toward CHP as scored by the American Council for an Energy-Efficient Economy (ACEEE).

Table 30. CHP Achievable Potential Data Sources

Input	Source	Website Link (if available)
Annual Market Penetration Rate	U.S. Department of Energy. "Combined Heat and Power Installation Database."	https://doe.icfwebservices.com/chpdb/
	Navigant. *2017 IRP Conservation Potential Assessment IRPAG Meeting Draft DSM Results.* Prepared for Puget Sound Energy. January 2017.	https://www.utc.wa.gov/_layouts/15/CasesPublicWebsite/GetDocument.ashx?docID=30&year=2016&docketNumber=160918
	U.S. Department of Energy. *Combined Heat and Power (CHP) Potential in the United States.* March 2016.	https://www.energy.gov/sites/prod/files/2016/04/f30/CHP%20Technical%20Potential%20Study%203-31-2016%20Final.pdf
	ICF International. *Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment*. Prepared for California Energy Commission. June 2012. CEC-200-2012-002-REV	http://www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002-REV.pdf
	ACEEE. "State-by-State CHP Favorability Index Estimate."	http://aceee.org/sites/default/files/publications/otherpdfs/chp-index.pdf

Using the ACEEE State-by-State CHP Favorability Index Estimate, we identified the top three most favorable states for CHP (California, Connecticut, and Massachusetts) and calculated the percentage of technical potential installed per year in these states over the five-year period 2012-2016. We also calculated this percentage for Washington state for comparison. This percentage is derived by dividing the capacity of CHP installed over the five-year period 2012-2016 (from the DOE CHP Installation Database) by the CHP potential (from the 2016 DOE CHP Potential in the United States) then dividing by five years. This provides an upper bound for the annual market penetration rate in PSE territory. Based on the benchmarking results (shown in Table 31) as well as the other data sources, we assumed an annual market penetration rate of 0.2% to provide the most likely and realistic achievable potential.

Table 31. Market Penetration for 2012-2016

State	MW Installed 2012-2016	Technical Potential (MW)	Percent of Technical Potential Installed Per Year
Washington	15.1	2,387	0.126%
California	382.2	11,542	0.662%
Connecticut	15.2	1,214	0.248%
Massachusetts	40.2	3,028	0.265%

Levelized Costs

For each technology, Cadmus calculated the levelized cost from a TRC perspective. Although assumptions varied between technologies, these sources were included in overall total resource levelized costs:

- Installation costs
- Federal tax credits and other rebates
- O&M costs assumed to occur annually, adjusted to the net present value
- Fuel costs

The levelized cost analysis used the sources shown in Table 32 as well as the sources listed above for technical and achievable potential. To calculate the TRC, Cadmus used PSE's inflation rate of 1.9% to adjust future costs to present dollars. The study divided costs by the system's production over its lifespan, obtaining the levelized cost of energy. Energy production includes PSE's average line loss factor of 6.80%, which represents avoided losses on the utility system, not energy losses from customer-sited units to the facility (assumed to be zero).

Table 32. CHP Levelized Cost Data Sources

Input	Source	Website Link (if available)
State Cost Adjustment	R.S. Means	N/A
Inflation and Discount Rate	PSE	N/A
Gas Rates and Gas Futures	Northwest Power and Conservation Council. *Fuel Price Forecast: Revised Fuel Price Forecasts for the Seventh Power Plan.* Table 1: Proposed Natural Gas at Henry Hub Price Range ($2012/MMBTU). pp. 11. July 2014.	https://www.nwcouncil.org/media/7113626/Council-FuelPriceForecast-2014.pdf
Installed Cost	U.S. Environmental Protection Agency. "Catalog of CHP Technologies." March 2015.	https://www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies.pdf
O&M Cost	Itron. *SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*. Appendix A. October 2015.	http://www.cpuc.ca.gov/General.aspx?id=7890
State and Federal Incentives and Tax Credits	U.S. Environmental Protection Agency. "dCHPP (CHP Policies and Incentives Database)."	https://www.epa.gov/chp/dchpp-chp-policies-and-incentives-database

Combined Heat and Power Results

Combined Heat and Power Technical Potential

Cadmus calculated technical CHP potential for new installations, based on sources described in the CHP Technical Potential Approach section of this report, including commercial and industrial customer data along with data on farms, landfills, and wastewater treatment facilities within PSE's power utility customer service area. This resulted in a total estimated 24-year, system-wide technical potential of 186 aMW (233 MW).

Table 33 details technical potential by area, sector, and fuel. These results exclude 83 MW of previous installed CHP capacity at eight facilities throughout PSE's territory.[7]

Table 33. CHP Technical Potential by Area, Sector, and Fuel (Cumulative in 2045)

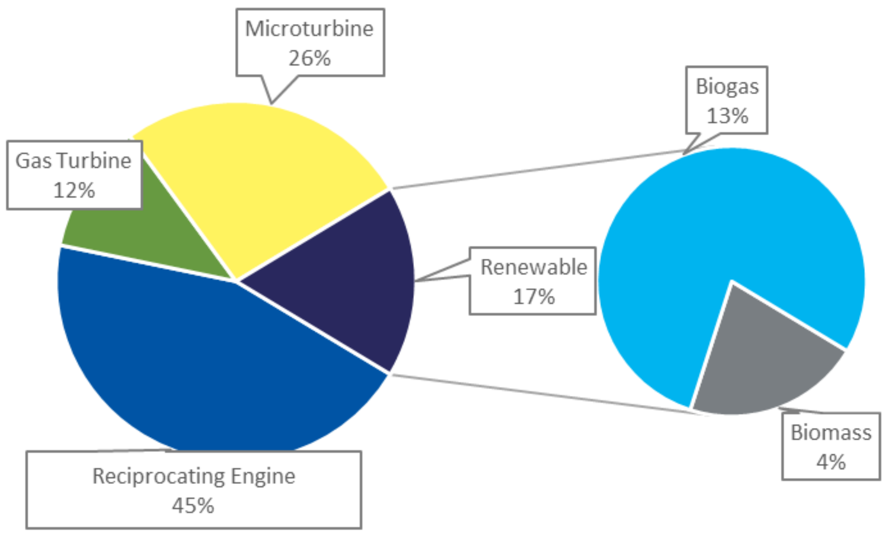
PSE	Technical Potential
Commercial	
Natural gas aMW	109
Number of sites	1,242
Industrial	
Natural gas aMW	56
Number of sites	293

7 U.S. Department of Energy. "Combined Heat and Power Installation Database." Accessed July 5, 2018.

PSE	Technical Potential
Biomass and biogas aMW	35
Number of sites	67
Industrial total aMW	91
Industrial total number of sites	360
Total	
Total aMW	200
Total number of sites	1,602

The study based average energy production on unique capacity factors for each system type. To avoid double-counting opportunities across technologies, the study divided total potential for each size range into different technologies. Figure 36 shows the distribution of technical potential as a percentage of 2045 technical potential in aMW by these different technologies (e.g., reciprocating engines, microturbines, gas turbines, biomass, biogas).

Figure 36. Percentage of 2045 CHP Technical Potential in aMW by Technology



Combined Heat and Power Achievable Potential

Cadmus applied a market penetration rate of 0.20% per year to the technical potential data to determine achievable potential or likely installations in future years. The study based the assumed annual market penetration rate on secondary research of naturally occurring CHP installations in the region and on other CHP potential study reports, as described in the *CHP Achievable Potential Approach* section. As shown in Table 34 and Table 35, the market penetration rate was applied to technical potential for each year to calculate equipment installations along with achievable potential over the next 24 years. The study estimated a cumulative 2045 achievable potential of 7.82 aMW (9.78 MW of installed capacity) at the generator. We used PSE's line loss assumption of 6.8%.

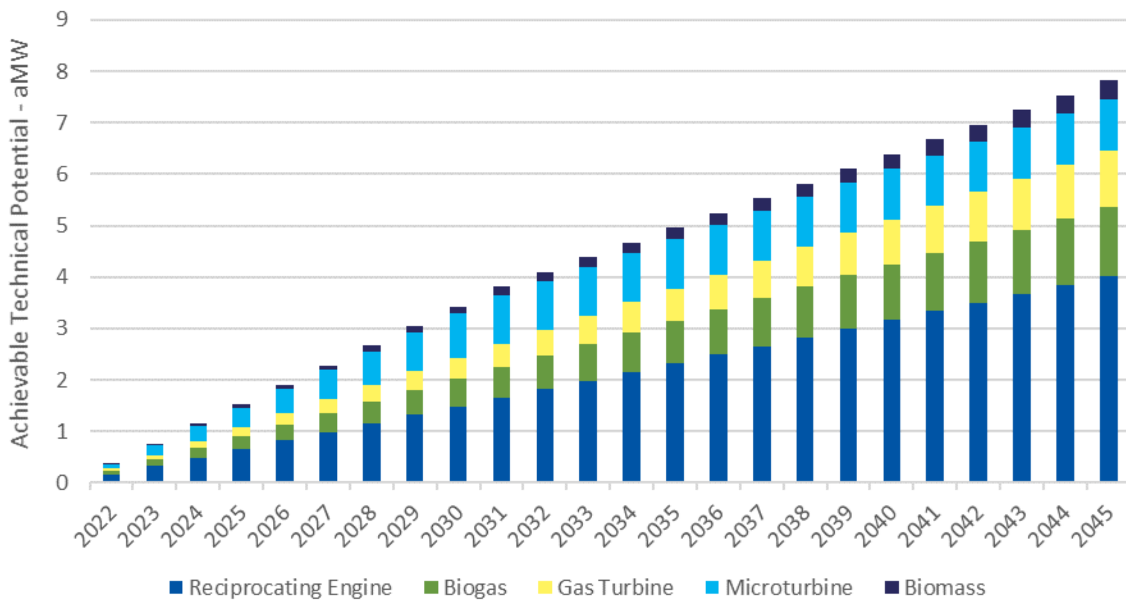
Table 34. CHP 2045 Cumulative Achievable Potential Equipment Installations

Technology	2045 Installs
Nonrenewable - Natural Gas (Total)	45
Reciprocating Engine	25
Gas Turbine	18
Microturbine	2
Renewables	2
Total CHP	47

Table 35. CHP 2045 Cumulative Achievable Potential at Generator

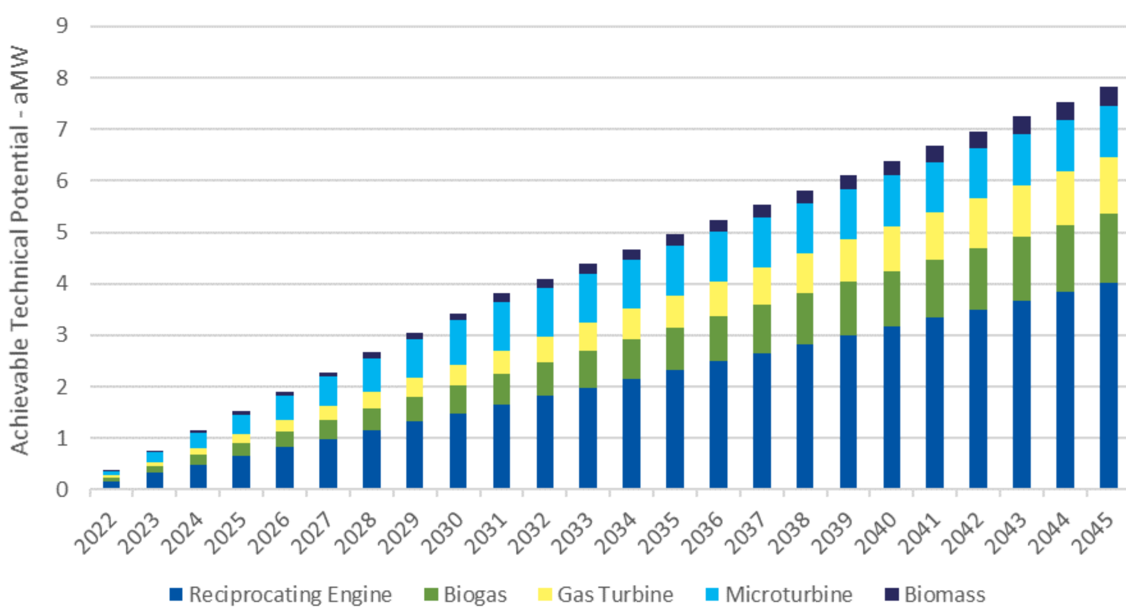
Technology	2045 aMW	2045 MW
Nonrenewable - Natural Gas (Total)		
30–99 kW	1.04	1.30
100–199 kW	0.83	1.04
200–499 kW	1.10	1.37
500–999 kW	0.76	0.96
1–4.9 MW	1.41	1.76
5 MW+	0.96	1.20
Renewable - Biomass (Total)		
< 500 kW	0.00	0.00
500-999 kW	0.00	0.00
1–4.9 MW	0.01	0.01
5 MW+	0.35	0.44
Renewable - Biogas (Total)		
Landfill	0.21	0.26
Farm	0.85	1.06
Paper Mfg	0.03	0.04
Wastewater	0.26	0.32
Total CHP	**7.82**	**9.78**

Figure 37. CHP Cumulative Achievable Potential by Year at Generation (aMW)



shows cumulative achievable CHP potential by year and technology. The decrease in the rate of adoption at year 2032 is caused by the assumed 10-year lifespan of microturbines. Microturbines are installed throughout the study horizon (2022-2045), but they don't begin to be decommissioned until 10 years after the start of the study. The rate for the first 10 years of the study is based on new installs, whereas the rate after the first 10 years includes new installs as well as decommissioned systems.

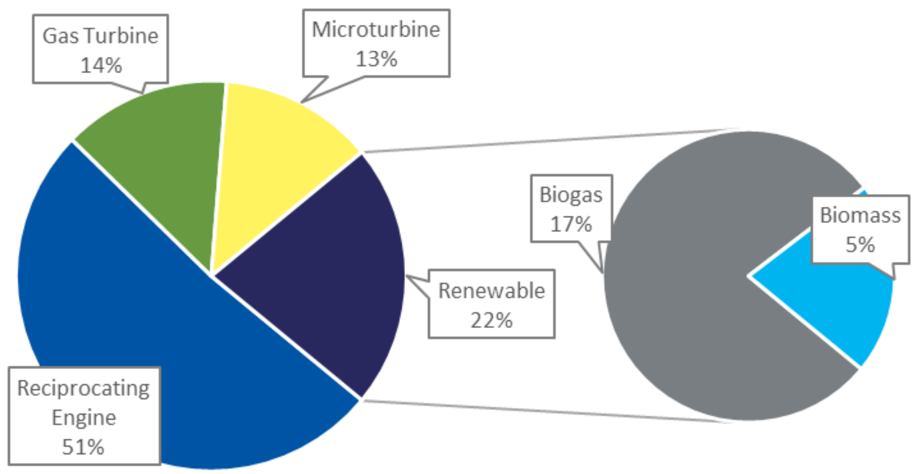
Figure 37. CHP Cumulative Achievable Potential by Year at Generation (aMW)



Of the 7.82 aMW of cumulative achievable potential, reciprocating engines made up 4.0 aMW (51%), gas turbines made up 1.3 aMW (14%), and microturbines made up 1.1 aMW (13%). The remaining 22%

of renewable technologies consisted of biogas (1.0 aMW) and biomass (0.4 aMW) systems. In 2045, total energy generated across all technologies is 68.5 GWh (i.e., nonrenewable at 53.5 GWh and renewable at 15 GWh). Figure 38 shows the market potential of energy generation by each technology.

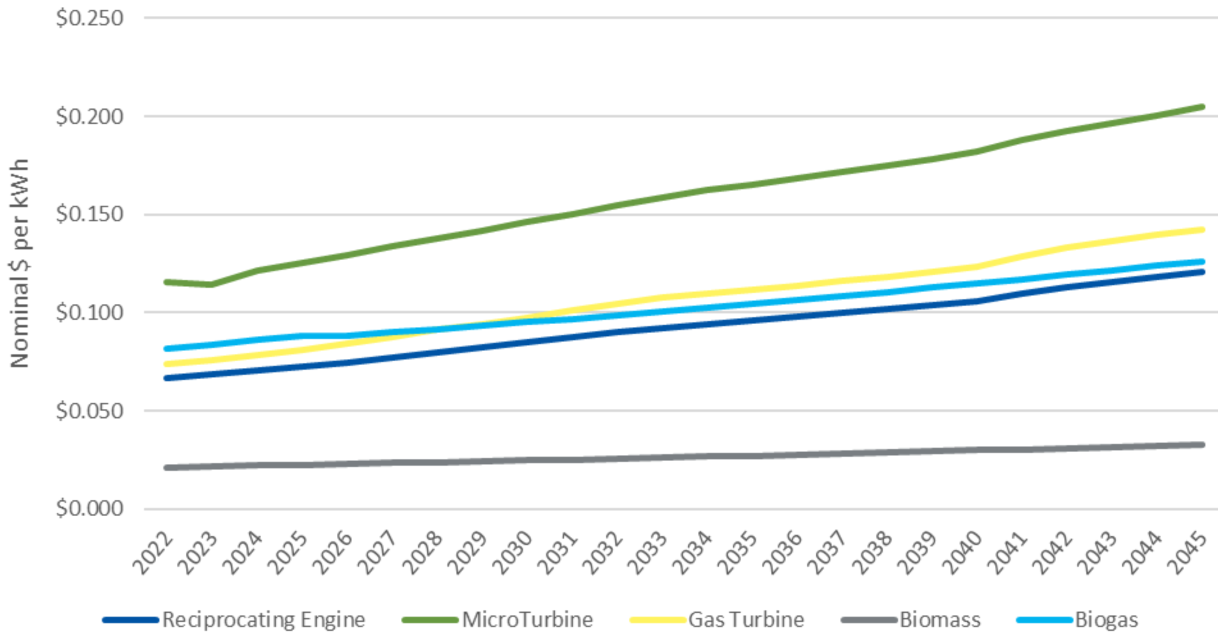
Figure 38. Breakout of CHP 2045 Cumulative Achievable Potential (GWh) at Generator



Combined Heat and Power Levelized Cost Results

Cadmus calculated the levelized cost, based on the TRC perspective, for each technology configuration in each installation year (2022 to 2045). Figure 41 shows the nominal levelized cost for units installed through the study period. The levelized cost increases slightly over time. For nonrenewable systems, the levelized cost increase results from increasing natural gas prices and inflation. For the renewable systems, the levelized cost increase results from inflation.

Figure 39. Nominal Levelized Cost by Technology and Installation Year



Section 2. Demand Response

Demand response programmatic options help reduce peak demand during system emergencies or periods of extreme market prices and promote improved system reliability. Demand response programs provide incentives for customers to curtail loads during utility-specified events (e.g., DLC programs) or offer pricing structures to induce participants to shift load away from peak periods (e.g., critical peak pricing (CPP) programs).

Overview of Technical and Achievable Potential

Cadmus' analysis focused on programs aimed at reducing PSE's winter peak demand. These programs include DLC space heat, DLC water heat, pricing, residential electric vehicle service equipment, residential behavioral, and nonresidential load curtailment and provide options for all major customer segments and end uses in PSE's service territory. Each of these programs may have more than one product option. For example, the nonresidential load curtailment program may offer customers a choice between manually turning off equipment to curtail loads or letting the utility communicate with an automated control system.

We defined each demand response program and its associated product option(s) according to typical program offerings, with particular specifications such as program implementation methods, applicable segments, affected end uses, load-reduction strategies, and incentives. To design the programs, we conducted an extensive review of secondary sources that addressed existing and planned programs predominantly in the Northwest, such as demand response potential assessments, program descriptions, evaluation reports, and pilot and demonstration projects from other utilities.

Estimate Technical Potential

Technical potential assumes 100% participation of eligible customers in all programs included in the assessment. Hence, technical potential represents a theoretical limit for unconstrained potential. Depending on the type of demand response product, this study applies either a bottom-up or a top-down method to estimate technical potential.

This study uses the bottom-up method for assessing potential for demand response programs that affect a piece of equipment in a specific end use, such as residential and commercial DLC space heat, residential DLC water heat, and residential electric vehicle service equipment. In the bottom-up method, technical potential is determined as the product of three variables: number of eligible customers, equipment saturation rate, and the expected per-unit (kW) peak load impact.

The top-down method estimates technical potential as a fraction of the participating facility's total peak-coincident demand. The calculation begins with disaggregating system electricity sales by sector, market segment, and end use then estimates technical potential as a fraction of the end-use loads. Total potential is then estimated by aggregating the estimated load reductions of the applicable end uses. The top-down estimation method is applied to demand response products that target the entire facility or load (rather than specific equipment), such as residential CPP, residential behavioral, commercial CPP, and commercial and industrial demand curtailment.

Estimate Achievable Potential

Achievable potential reflects a subset of technically feasible demand response opportunities that are assumed to be reasonably obtainable, based on market conditions and the end-use customers' ability and willingness to participate in the demand response market. There are two components for estimating achievable potential: market acceptance (or the participation rate) and the ramp rate. The participation rate is also broken down into program participation (the likelihood of the eligible population to enroll in a demand response program) and event participation (the probability that customers participating in a program will respond to a demand response event), an important consideration in voluntary demand response programs.

Ramp rates reflect the time needed for product design, planning, and deployment. Ramp rates vary depending on the type of demand response product and the stage in the product's life cycle. Ramp rates indicate when the maximum achievable potential may be reached, but they do not affect the amount of maximum achievable potential.

Both top-down and bottom-up methods calculate achievable potential as the product of peak load impact, program participation, and event participation, but note that event participation is assumed as 100% in involuntary load reduction programs such as DLC. Both methods apply ramp rates in the same manner to account for program start-up and ramp-up.

Calculate Levelized Costs

In the context of demand response, levelized cost of electricity (LCOE) represents the constant per-kilowatt-year cost of deploying and operating a demand response product, calculated as follows:

LCOE = (Annualized Cost of Demand Response Product) / (Achievable Annual Kilowatt Load Reduction)

This assessment calculated levelized costs based on the total resource cost (TRC) perspective, which includes all known and quantifiable costs related to demand response products and programs. The calculation of each demand response product's levelized cost accounts for the relevant, direct costs of a demand response product, including setup costs, program operation and maintenance costs, equipment cost, marketing cost, incentives, and transmission and distribution (T&D) deferral costs:

- **Upfront setup cost.** This cost item includes PSE's program development and setup costs for delivery of the subject demand response products, prior to program implementation. Because upfront costs tend to be small relative to total program expenditures, they can be expected to have a small effect on levelized costs.
- **Program operations and maintenance (O&M) cost.** This cost item includes all expenses that PSE incurs annually to operate and maintain the program. Expenses may cover administration, event dispatching, customer engagement, infrastructure maintenance, managing opt-outs and new recruiting of loads, and evaluation.
- **Equipment cost (labor, material, and communication costs).** This cost item includes all expenses necessary to enable demand response technology for each participating end user. The cost item applies only to each year's new participants. For some programs that assume or

require end users to already have demand response technology in place, this cost item would be zero.

- **Marketing cost.** This cost item includes all expenses for recruiting end users' participation in the program and applies only to new participants each year. For some programs (typically those run by third-party aggregators), the program O&M cost already includes this cost item.
- **Incentive.** This cost item covers all incentives offered to end users each year. Incentives may take the form of fixed monthly or seasonal bill credits or may be variable, tied to actual kilowatt load reduction. This assessment included 100% of the assumed incentive payment to eligible participants in the TRC levelized-cost calculation
- **Transmission and distribution (T&D) costs.** A transmission and distribution deferral value of $15.15/kW-year was included as a negative cost item in the levelized cost calculations for each product.
- **Discount rate.** A 6.8% discount rate, consistent with PSE's resource planning assumptions, was used for all demand response products.
- **Product life cycle.** All demand response products were assessed with an assumed 24-year life cycle.

Develop Supply Curves

Demand response supply curves show the quantity-price relationships for the demand response products that are being considered at the end of the planning period. A supply curve shows the incremental and cumulative achievable potential for a set of demand response products, in the ascending order of their levelized costs.

Demand Response Potential

This section introduces the analysis scope for assessing demand response potential in PSE's electric service territory, followed by a summary of potential results of the demand response programs and detailed descriptions of each program, including the product options and associated input assumptions.

Scope of Analysis

Focusing on reducing a utility's capacity needs, demand response programs rely on flexible loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost. These programs seek to help reduce peak demand and promote improved system reliability. In some instances, the programs may defer investments in delivery and generation infrastructure.

Demand response objectives may be met through a broad range of strategies, both price-based (such as time-of-use [TOU] or interruptible tariff) and incentive-based (such as DLC) strategies. This assessment considered 16 total demand response product options to estimate total achievable technical demand response potential in PSE's service area during peak load in winter and summer. These product options included multiple residential and commercial DLC products targeting cooling, heating, and water heating end uses as well as electric vehicle service equipment (EVSE), commercial and industrial products such as demand curtailment contracts and interruptible tariffs, and other non-dispatchable products such as residential behavior demand response.

Demand response potential estimates invariably require assumptions regarding program design – including the number and duration of events – even in instances where utilities, such as Puget Sound Energy, who currently do not offer demand response programs. For this study, Cadmus assumed an average of 40 hours of dispatch (ten, four-hour events) for DR products. Typically, larger commitments lead to lower potential estimates resulting from less load reduction capability over longer duration event and higher customer program attrition and lower customer event participation for higher numbers of events. Utility contracts with third-party DR service providers typically stipulate a limited number of events, event duration, and notification level for utility DR programs.

Cadmus reviewed recent demand response literature, including evaluations of pilots and programs in the Northwest and across the country, to design each demand response program. All but three of the evaluated product groups have two product options to capture the most common demand response product strategies from benchmarked studies. For example, customers participating in the residential DLC space heat program can either have a programmable communicating thermostat (PCT) installed in their home free of charge or let the utility communicate with the home's existing programmable PCT and receive a one-time bonus incentive.

Summary of Resource Potential

Table 36 lists the estimated resource potentials for all winter demand response programs for the residential, commercial, and industrial sectors during winter. The greatest achievable potential occurs in the residential sector from the DLC programs. Note that this analysis does not account for program interactions and overlap; therefore, the total achievable potential estimates may not be fully attainable upon implementation of all programs. The system peak load is calculated as the average of PSE's hourly loads during the 20 highest-load hours in the winter of 2019.

Table 36. Demand Response Achievable Potential and Levelized Cost by Product Option, Winter 2045

Program	Product Option	Winter Achievable Potential (MW)	Winter Percent of System Peak	Levelized Cost ($/kW-year)
Residential CPP	Res CPP-No Enablement	64	1.28%	-$3
	Res CPP-With Enablement	2	0.04%	-$8
Residential DLC Space Heat	Res DLC Heat-Switch	50	1.00%	$71
	Res DLC Heat-BYOT	3	0.06%	$61
Residential DLC Water Heat	Res DLC ERWH-Switch	11	0.21%	$126
	Res DLC ERWH-Grid-Enabled	58	1.15%	$81
	Res DLC HPWH-Switch	< 1	< 0.1%	$329
	Res DLC HPWH-Grid-Enabled	1	0.02%	$218
Commercial CPP	C&I CPP-No Enablement	1	0.03%	$86
	C&I CPP-With Enablement	1	0.02%	$81
Commercial DLC Space Heat	Small Com DLC Heat-Switch	7	0.13%	$64
	Medium Com DLC Heat-Switch	5	0.10%	$29
Commercial and Industrial Curtailment	C&I Curtailment-Manual	3	0.06%	$95
	C&I Curtailment-AutoDR	3	0.06%	$127
Residential EVSE	Res EV DLC	9	0.17%	$361
Residential Behavioral	Res Behavior DR	9	0.17%	$76

Although PSE's electric distribution system incurs peak demand in winter, Cadmus also estimated the demand response potential for the summer season, as Table 37 shows. The remainder of the results presented in the demand response section focus on the winter demand response potential.

Table 37. Demand Response Achievable Potential and Levelized Cost by Product Option, Summer 2045

Program	Product Option	Summer Achievable Potential (MW)	Summer Percent of System Peak	Levelized Cost ($/kW-year)
Residential CPP	Res CPP-No Enablement	39	1.0%	$5
	Res CPP-With Enablement	1	< 0.1%	< $1
Residential DLC Space Heat	Res DLC Heat-Switch	24	0.6%	$160
	Res DLC Heat-BYOT	31	0.8%	$61
Residential DLC Water Heat	Res DLC ERWH-Switch	11	0.3%	$158
	Res DLC ERWH-Grid-Enabled	58	1.4%	$81
	Res DLC HPWH-Switch	< 1	< 0.1%	$406
	Res DLC HPWH-Grid-Enabled	1	< 0.1%	$218
Commercial CPP	C&I CPP-No Enablement	9	0.2%	$117
	C&I CPP-With Enablement	18	0.5%	$17
Commercial DLC Space Heat	Small Com DLC Heat-Switch	4	0.1%	$95
	Medium Com DLC Heat-Switch	4	0.1%	$126
Commercial and Industrial Curtailment	C&I Curtailment-Manual	2	< 0.1%	$41
	C&I Curtailment-AutoDR	3	0.1%	$36
Residential EVSE	Res EV DLC	9	0.2%	$361
Residential Behavioral	Res Behavior DR	5	0.1%	$77

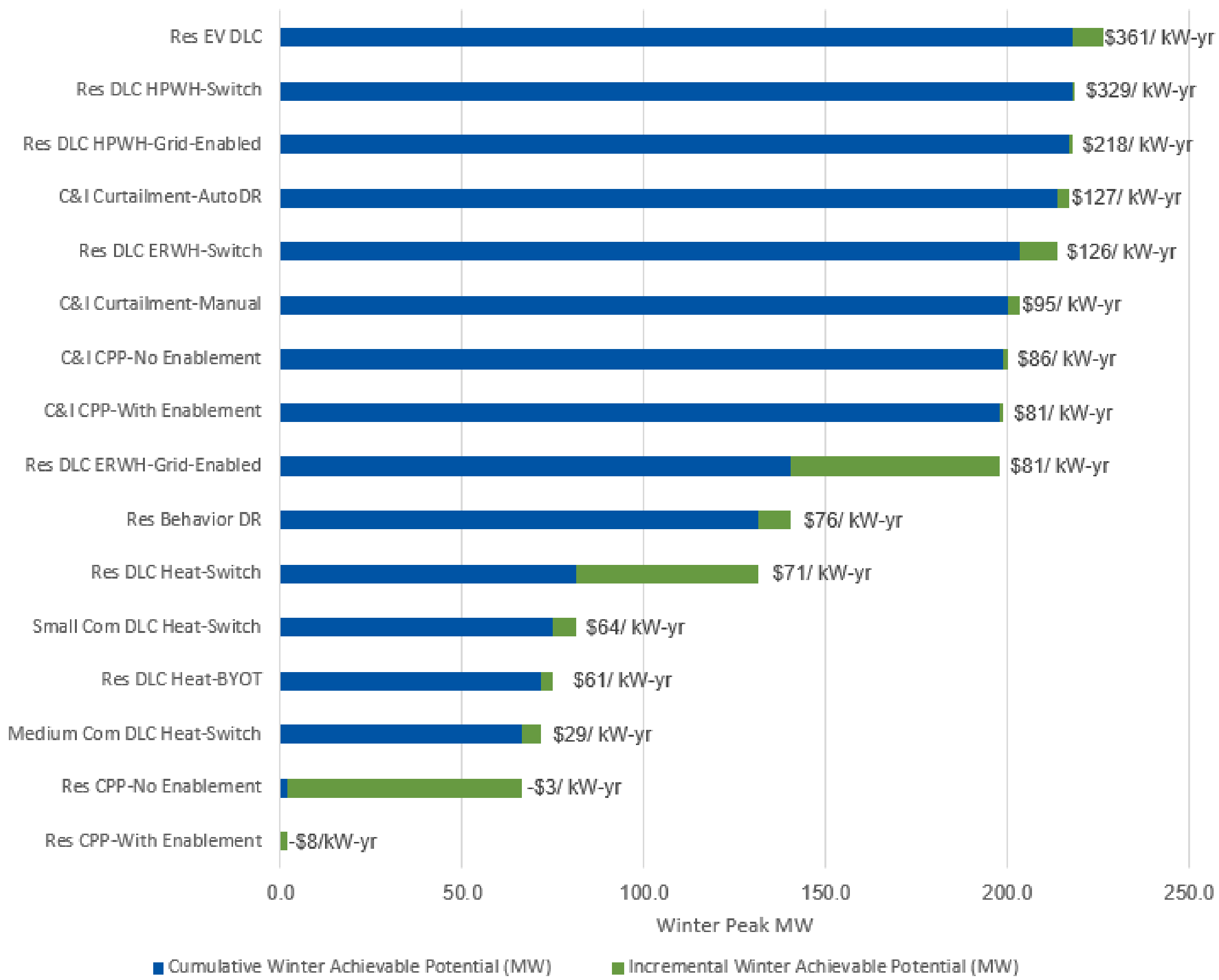
Cadmus constructed supply curves from quantities of estimated achievable technical demand response potential and per-unit levelized costs for each product option. Figure 40 shows the quantity of achievable potential (available during the system winter peak hours in 2045) as a function of levelized costs, at the product-option level. The green bars represent the incremental, achievable potential available for a product option at its associated levelized cost. The blue bars represent the cumulative achievable potential for the product options with lower levelized costs.

The supply curve starts with the lowest cost product option—residential CPP with enablement, which provides 2 MW of winter achievable potential at -$8 per kilowatt-year, levelized. The next lowest cost product in the supply curve is the same program but for the product option of no enablement, which adds 64 MW of winter achievable potential at -$3 per kilowatt-year, levelized. Thus, PSE could acquire a total of 66 MW of winter demand response at a negative levelized cost.

The two most cost-effective DR product options mentioned have negative costs due to the inclusion of deferred T&D costs in the TRC levelized cost calculation. Cadmus incorporated a transmission and distribution deferral value of $15.15/kW-year as a negative cost item in the levelized cost calculations for each product, resulting in negative values for products with very low costs. Without the inclusion of the T&D deferral value, the levelized costs of residential CPP with enablement and residential CPP with no enablement are $8 and $12, respectively.

Because residential EV DLC is the most expensive product option, PSE could acquire as much winter potential as achievable if it paid $361 per kilowatt-year (i.e., the levelized cost for the most expensive product option). However, PSE could acquire approximately 90% of the total achievable technical winter demand response potential at $95 per kilowatt-year, which is less than a third of the levelized cost of the most expensive product.

Figure 40. Demand Response Achievable Potential Supply Curve by Product Option



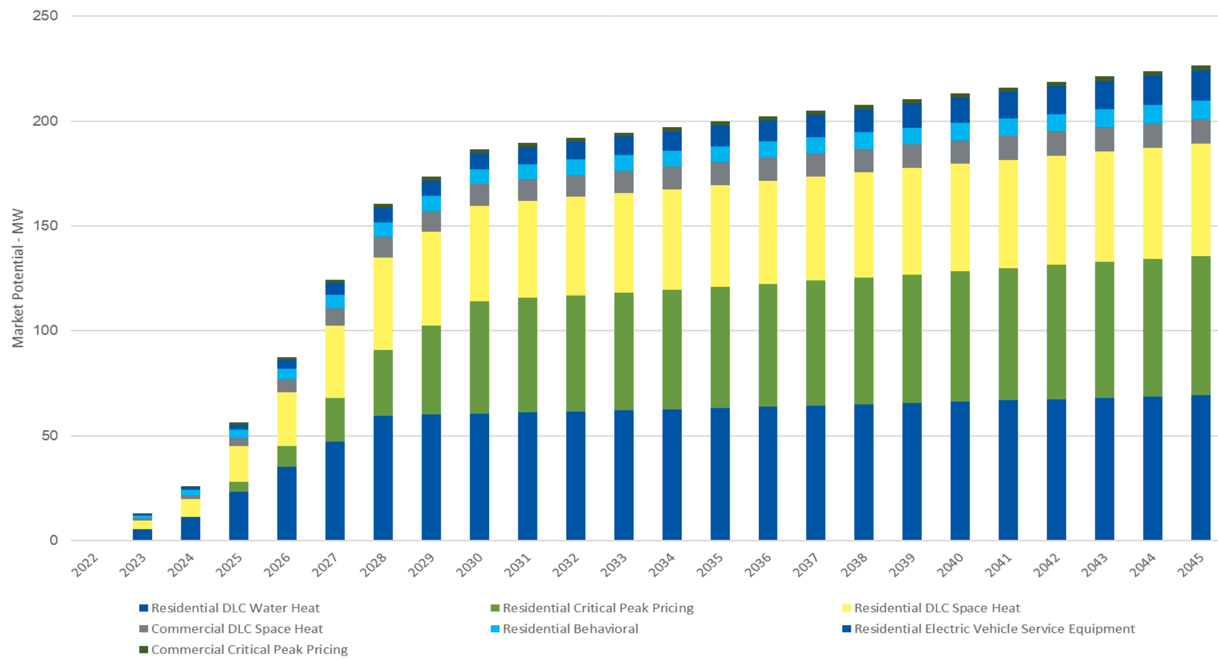
Cadmus assumes each program will require seven years of implementation before achieving the maximum achievable level of participation, allowing for an ample start-up period. Exceptions to this rule include:

- Residential Behavioral requires six years as this program would be an add-on to PSE's existing behavioral energy efficiency program, warranting a shorter ramp period than other DR programs.
- Residential Electric Vehicle Service Equipment requires five years to align with the 2021 Plan assumption to reach full program engagement.
- Residential DLC Heat – BYOT requires 5 years to align with ramp rate assumptions used in the 2021 Plan.

- CPP requires that PSE first establish a TOU tariff; therefore, the study assumed zero CPP participation until 2025.

Figure 41 shows the acquisition schedule for achievable potential by program.

Figure 41. Demand Response Achievable Potential Forecast by Program



Detailed Resource Potentials by Program and Product Option

This section provides the detailed demand response achievable potential and levelized cost for each program and its product options. For each program, Cadmus also describes the available product options and provides the costs and impact input assumptions.

Residential Critical Peak Pricing

Under a CPP program, customers receive a discount on their retail rates during noncritical peak periods in exchange for paying premium prices during critical peak events. The critical peak price is determined in advance, which gives customers some degree of certainty about participation costs.

The program follows the basic rate structure of a TOU tariff, where the rate has fixed prices for usage during different blocks of time (typically on-, off-, and mid-peak prices by season). During CPP events, the normal peak price under a TOU rate structure is replaced with a much higher price, which is generally set to reflect the utility's avoided cost of supply during peak periods.

CPP rates take effect for only a limited number of times during the winter. When emergency or high market prices are in effect, the utility can invoke a critical peak event. The utility notifies customers that rates have become much higher than normal and encourages them to shed or shift load. Typically, notification is via email or text a day prior to the CPP event and the day of the event. This analysis assumes that 10 critical peak price events are called, with a duration of four hours, for a total of 40 event hours during the winter.

Product Options

According to Cadmus' research of existing program studies across the nation, peak load impacts achieved by CPP programs vary depending on if the enabling technology, such as programmable communicating thermostats (PCTs), are integrated with the program. This analysis estimated two product options in the residential CPP program:

- No enablement (for customers without existing PCT)
- With enablement (for customers with existing PCT)

This analysis assumes that residential customers eligible for the with-enablement option have an existing PCT to control their central electric space heating equipment (i.e., electric furnace or air-source heat pump). During a critical peak event, these customers can reduce 40% of their space heat load, in addition to other end-use loads. All other residential customers are eligible for the no-enablement product option and achieve a relatively lower peak load impact.

Input Assumptions

Table 38 provides the cost and impact assumptions that Cadmus used in estimating potential and levelized costs for the residential CPP program.

Table 38. Residential Critical Peak Pricing Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	Assuming 1 FTE to set up the program.
O&M Cost	$ per year	$75,000	SDG&E (2017): $280,000; Applied (2017): $75,000. Assuming 0.5 FTE for the program.
Equipment Cost	$ per new participant	$0	No enablement: According to PSE (2018), AMI will be fully deployed in PSE's electric territory by 2023. Therefore, no equipment cost is incurred.
			With enablement: Because participant already has a PCT, no equipment cost is incurred.
Marketing Cost	$ per new participant	$25	Cadmus (2015): $25/new participant; Cadmus (2017): $25/new participant; Applied (2017): $50/new participant.
Incentives (annual)	N/A	$0	Program definition
Incentives (one time)	N/A	$0	Program definition
Attrition	% of existing participants per year	0%	N/A
Eligibility	% of segment load	Varies by product option and segment	No enablement: The proportion of residential customers who are not eligible for the with-enablement option.
			With enablement: The proportion of residential customers with a PCT (PSE's 2018 RCS) and have electric furnaces or air-source heat pumps (RBSA; heating zone 1).
Peak Load Impact	% of eligible segment load	Varies by product option and end use	No enablement: assuming 12% based on Cadmus (2015): 12%; Cadmus (2017): 12%; Applied (2017): 12.5%; and Brattle (2015): 14.8%.

Parameters	Units	Values	Notes
			With enablement: For cool central, heat central, and heat pump end uses, assuming 40% based on Oklahoma (2011): 38.8%; DTE (2014): 44.5%; Nexant (2017) 44.6%. For other end uses, assuming 12%.
Program Participation	% of eligible segment load	15%	Cadmus (2013b): 5%; Cadmus (2015): 10%; Cadmus (2017): 10%; Applied (2017): 17%; Brattle (2015): 29%.
Event Participation	N/A	No enablement: 100%	No enablement: peak load impact already takes into account of event participation.
		With enablement: 85%	With enablement: Customers can override the impact on their HVAC end uses by adjusting their PCTs.

Results

Residential CPP is the least expensive demand response program. As a tariff-based product, it does not offer incentives for load reductions. Without any enabling technology, residential CPP could obtain 64 MW of winter achievable potential by 2045 at -$3 per kilowatt-year, as shown in Table 39. Participating customers with enabling technology can provide even more peak load reductions, and—because PSE does not pay for the existing enabling technology—this peak load reduction is at a lower levelized cost of -$8 per kilowatt-year. Note that the potential results represent the load impact of a CPP event, during which only CPP prices are in effect.

Table 39. Residential Critical Peak Pricing Achievable Potential and Levelized Cost by Product Option

Product Option	Number of Events and Hours Curtailed	Notification Type	Levelized Cost ($/kW-year)	24-Year Achievable Potential (MW)
Res CPP-No Enablement	10 4-hour events	Day-ahead	-$3	64
Res CPP-With Enablement	10 4-hour events	Day-ahead	-$8	2

Residential Direct Load Control Space Heat

DLC programs seek to interrupt specific end-use loads at customer facilities through utility-directed control. When necessary, the utility, typically through a third-party contractor, is authorized to cycle or shut off participating appliances or equipment for a limited number of hours on a limited number of occasions. Customers do not have to pay for the control equipment or installation costs and typically receive incentives that are paid through monthly credits on their utility bills.

Product Options

For programs that target central electric space heating (i.e., heat pumps and electric forced-air furnaces), load control switches or PCTs are connected to a digital internet gateway. Load control switches allow the utility to cycle electric heating equipment on and off during peak events while PCTs automatically set back temperature setpoints on heating systems. For this analysis, two product options are offered:

- Bring-your-own-thermostat (BYOT) (for customers with existing PCT)

- Load control switches (for customers without existing PCT)

DLC programs have mandatory event participation once a customer elects to participate in the program. However, for the PCT product option, this analysis assumes that customers are able to opt out or override their participation in an event by readjusting their thermostat.

Input Assumptions

Table 40 lists the cost and impact assumptions that Cadmus used in estimating potential and levelized costs for the residential DLC space heat program.

Table 40. Residential Direct Load Control Space Heat Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	Assuming 1 FTE to set up the program.
O&M Cost	$ per participant per year	$7.50	The annual program administrative cost assumes 1 FTE at $150,000 per year per 20,000 residential participants. In PSE's 2015 CPA, admin costs were 5% of total costs and vendor costs were 15% of total costs (Cadmus 2015).
Equipment Cost	$ per new participant	BYOT: $0	BYOT: Because participant already has a PCT, no equipment cost is incurred.
		Switches: $215	Switches: Based on Applied (2017): $215 ($115 for the switch and $100 for installation). Other sources include Potter (2017): $166 (for the control technology, installation, and communication platform); Global (2011): $170; Navigant (2012): $370; Navigant (2015a) for central air-conditioning DLC: $125-$189 (including $60 switch); Xcel (2016) for central air-conditioning DLC: $150-$200 (equipment).
Marketing Cost	$ per new participant	$25	Range for DLC programs: Navigant (2012) $25; Applied (2017) $50; Brattle (2014) $80; Applied (2017) $50.
Incentives (annual)	$ per participant per year	$40	Assuming $10/month for the season (i.e., November to February). Applied (2017): $20; Navigant (2012): $32; Global (2011): $50.
Incentives (one time)	$ per new participant	$0	N/A
Attrition	% of existing participants per year	5%	Consistent with the residential DLC water heat program.
Eligibility	% of customer count (e.g. equipment saturation)	Varies by product option and segment	BYOT: The proportion of residential customers with a PCT (PSE's 2018 RCS) and have electric furnaces or air-source heat pumps (RBSA; heating zone 1). Switches: The proportion of residential customers without a PCT (PSE's 2018 RCS) and have electric furnaces or air-source heat pumps (RBSA; heating zone 1).
Peak Load Impact	kW per participant (at meter)	BYOT: 1.09	Based on 2021 Plan Workbook "Inputs_Product_ResBYOT-Winter" peak load impact assumption. Available at: https://nwcouncil.app.box.com/s/osjwinvjiomgo7vd4uc75y16z3x9b32i/file/655872907903
		Switches: 1.2	Based on 2021 Plan Workbook "Inputs_Product_ResHeatSwch-Winter" peak load impact assumption. Available at: https://nwcouncil.app.box.com/s/osjwinvjiomgo7vd4uc75y16z3x9b32i/file/655862892198
Program Participation	% of eligible customers	20%	Navigant (2012), Applied (2017), and Brattle (2016) use 20%. Global (2011) gives low- and high-range of 15% - 25%.

Parameters	Units	Values	Notes
Event Participation	%	BYOT: 80%	BYOT: Customers can override the impact on their space heating by adjusting their PCTs (IPL 2014).
		Switches: 94%	Switches: Space heat and central air-conditioning DLC programs for switch success rate range from 64% (Navigant 2012) to 96% (ConEd 2012; NIPSCO 2016). Using Cadmus (2013b) assumption.

Results

Table 41 shows that the residential DLC space heating program could, by 2045, obtain 53 MW of achievable potential in the winter. The switches option provides most of the achievable potential, at a levelized cost of $71 per kilowatt-year. Although it cannot provide much achievable potential, the bring-your-own-thermostat option is cheaper, at a levelized cost of $61 per kilowatt year.

Table 41. Residential Direct Load Control Space Heat Achievable Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed	Notification Type	Levelized Cost ($/kW-year)	24-Year Achievable Potential (MW)
Res DLC Heat-Switch	10 4-hour events	0-min	$71	50
Res DLC Heat-BYOT	10 4-hour events	0-min	$61	3

Residential Direct Load Control Water Heat

Water heating DLC programs directly control water heaters in customers' homes via load control switches. Communication between the utility and these switches can occur through advanced metering infrastructure (AMI) infrastructure, radio, consumer Wi-Fi connections to the internet, power line carrier, or paging infrastructure as well as through other web-based communications. Several other technologies, such as grid-enabled water heaters (GEWH) and water heater timers, exist for curtailing water heating energy usage during peak hours.

Product Options

All residential customers with electric storage water heaters are eligible to participate in the residential DLC water heat program. This analysis involves two product options for the residential DLC water heat program: load control switches and grid-enabled water heaters. However, considering the peak savings between electric-resistance water heaters (ERWH) and heat pump water heaters (HPWH) differ, this analysis split the eligible participants of these two product options between these two water heater types according to equipment saturations. The result was the following four product permutations for this simulated DLC water heat DR program:

- ERWH – Load control switches
- ERWH – GEWH
- HPWH – Load control switches
- HPWH - GEWH

For the switches class of product options, the utility installs the switch on customers' existing electric water heaters. This study assumed water heaters are cycled off for 50% of the event's duration. Because most electric water heaters use tank storage systems, which allow customers to draw on stored hot water during event times, the water heater load shifts on and off every 20 or 30 minutes during the event. The assessment assumes this product option will be available for four-hour duration events with up to 10 events per year.

The other class of product options is for customers who own GEWH. These water heaters are manufactured with an ANSI/CTA-2045 port that allows a universal communication device to be plugged in, enabling two-way connection to the utilities' grid infrastructure. The primary advantages of this built-in communication capability include the opportunity for greater participation in water heater DLC programs. These water heaters can also be controlled more often, potentially serving other utility grid needs.[8]

Washington State recently passed legislation that mandated electric storage water heaters manufactured on or after January 1, 2021, to comply with the modular demand response communications interface standard, ANSI/CTA–2045-A, or equivalent.[9] As a result, all new electric storage water heaters after 2021 will be GEWH and thus will be eligible for the GEWH product option. This analysis incorporates estimated impacts of this legislation by shifting most of the program participants to the GEWH products from the switch products over time for each water heater type.

Input Assumptions

Table 42 provides the cost and impact assumptions that Cadmus used in estimating potential and levelized costs for the residential DLC water heat program.

Table 42. Residential Direct Load Control Water Heat Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	Assuming 1 FTE to set up the program.
O&M Cost	$ per participant per year	$7.50	Assuming annual program O&M cost is 1 FTE at $150,000 per year per 20,000 residential participants.
Equipment Cost	$ per new participant	Switches: $315	Switches: Cadmus (2018) and Applied (2017). Range: Potter (2017) $350; Navigant (2015a): $106; Navigant (2012): $280 (space heat and water heat combined, additional $275 for gateway).

8 Bonneville Power Administration. CTA-2045 Water Heater Demonstration Report. November 9, 2018. Available online: https://www.bpa.gov/EE/Technology/demand-response/Documents/Demand%20Response%20-%20FINAL%20REPORT%20110918.pdf

9 State of Washington. Second Substitute House Bill 1444, Certification of Enrollment. An act relating to appliance efficiency standards; amending RCW 19.260.010, 19.260.030, 19.260.040, 19.260.050, 19.260.060, and 19.260.070; reenacting and amending RCW 19.260.020; adding a new section to chapter 19.260 RCW; creating a new section; and repealing RCW 19.27.170. Passed April 18, 2019. http://lawfilesext.leg.wa.gov/biennium/2019-20/Pdf/Bills/House%20Passed%20Legislature/1444-S2.PL.pdf

Parameters	Units	Values	Notes
		GEWH: $40	GEWH: According to BPA (2018), communication device cost per tank will drop from $100 to $15 over 20 years as volume increases. Assuming $40 per tank (Eustis 2018).
Marketing Cost	$ per new participant	$25	Range for DLC programs: Navigant (2012) $25; Applied (2017) $50; Brattle (2014) $80; Applied (2017) $50. According to BPA (2018), marketing cost per participant will drop from $150 to $25 over 20 years.
Incentives (annual)	$ per participant per year	$24	Assuming $2 per month for 12 months. Researched range: Applied (2017): $24-$25; Duke Energy (2015): $25; Navigant (2011): $8; BPA (2014): $4/month.
Incentives (one time)	$ per new participant	$0	N/A
Attrition	% of existing participants per year	5%	Cadmus (2011).
Eligibility	% of customer count (e.g., equipment saturation)	Varies by product option and segment	Electric water heat saturation was split between ERWH and HPWH based on RCS 2017 data. Ramp rate was adjusted to account for the growth in GEWH saturation over time. Methodology for ramp rate adjustment was informed by the 2021 Plan workbook "Inputs_Product_ResERWHDLCG-Winter". Available at: https://nwcouncil.app.box.com/s/osjwinvjiomgo7vd4uc75y16z3x9b32i/file/655867071789
Peak Load Impact	kW per participant (at meter)	ERWH: 0.58	ERWH: Cadmus (2015), Applied (2017), Navigant (2015a), and BPA (2014): 0.58 kW. Duke Energy (2015) 0.4 kW; Global (2011) 0.5 kW; Navigant (2011) 0.49 kW - 0.77 kW.
		HPWH: 0.24	HPWH: Based on weighted value from pilot results presented in March, 2018 (Eustis 2018).
Program Participation	% of eligible customers	Switches: 25%	Switches: Applied (2017) 15% - 23%; Global (2011) 15% - 25%; Navigant (2012) 20%; Navigant (2015a) 20% - 30% (realistic - max achievable).
		GEWH: 24%	GEWH: Based on BPA (2018) market transformation strategies. Program participation assumption adjusted down by half
Event Participation	% (switch success rate)	95%	Consistent with residential DLC space heat program.

Results

Table 43 presents assessment results for the residential DLC water heat program. The ERWH GEWH option could provide 58 MW of winter achievable potential by 2045, at a levelized cost of $81 per kilowatt-year. The ERWH load control switch option could add 11 MW of winter achievable potential at a levelized cost of $126 per kilowatt-year.

Table 43. Residential Direct Load Control Water Heat Achievable Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed	Notification Type	Levelized Cost ($/kW-year)	24-Year Achievable Potential (MW)
Res DLC ERWH-Switch	10 4-hour events	0-min	$126	11
Res DLC ERWH-Grid-Enabled	Unlimited	0-min	$81	58
Res DLC HPWH-Switch	10 4-hour events	0-min	$329	0.2

Product Option	Number of Events and Hours Curtailed	Notification Type	Levelized Cost ($/kW-year)	24-Year Achievable Potential (MW)
Res DLC HPWH-Grid-Enabled	Unlimited	0-min	$218	1

Commercial Critical Peak Pricing

The commercial CPP program is similar to the residential CPP program but for small and medium commercial customers.

Product Options

Commercial customers in the small or medium office or retail segments are eligible for the commercial DLC space heat program. Small office customers were defined as having a building square footage of less than 20,000, while medium office customers were those with a building square footage between 20,000 and 100,000. For retail, these square footage definitions were under 5,000 and between 5,000 and 50,000 for small and medium customers, respectively. According to existing program studies across the nation, peak load impacts achieved by CPP programs vary depending on if enabling technology such as PCTs are integrated with the program. This analysis estimated two product options within the commercial CPP program:

- No enablement (for customers without existing PCT)
- With enablement (for customers with existing PCT)

This analysis assumes that small and medium commercial customers with an existing PCT to control their electric space heating equipment (i.e., electric furnace or air-source heat pump) are eligible for the with-enablement option and can reduce 7% of their space heat load during a critical peak event, in addition to other end-use loads. All other small and medium commercial customers are eligible for the no-enablement product option and achieve a lower peak load impact.

Input Assumptions

Table 44 lists cost and impact assumptions that Cadmus used in estimating potential and levelized costs for the commercial CPP program.

Table 44. Commercial Critical Peak Pricing Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	Assuming 1 FTE to set up the program.
O&M Cost	$ per year	$75,000	SDG&E (2017): $280,000; Applied (2017): $75,000. Assuming 0.5 FTE.
Equipment Cost	$ per new participant	$0	No enablement: According to PSE (2018), AMI will be fully deployed in PSE's electric territory by 2023. Therefore, no equipment cost is incurred.
			With enablement: Because participant already has a PCT, no equipment cost is incurred.
Marketing Cost	$ per new participant	$50	Applied (2017): $50/new participant for small and medium commercial customers.

Parameters	Units	Values	Notes
Incentives (annual)	N/A	$0	Program definition
Incentives (one time)	N/A	$0	Program definition
Attrition	% of existing participants per year	0%	N/A
Eligibility	% of segment load	Varies by product option and segment	No enablement: The proportion of each segment's commercial customers that are not eligible for the with-enablement option.
			With enablement: The proportion of customers in small office, small retail, medium office, and medium retail with electric furnaces or air-source heat pumps (CBSA), assuming these customers have a PCT to control their heating load.
Peak Load Impact	% of eligible segment load	5%	No enablement: For small commercial customers, estimates ranged from 2.5% to 12.2% (Nexant 2017). For medium commercial customers, estimates ranged from 1.9% to 2.5% (Nexant 2017).
		7%	With enablement: Nexant (2017) reported 7% for participants with a PCT.
Program Participation	% of eligible segment load	10%	Assuming an opt-in program, estimates range from 2% (Cadmus 2015) to 18% (Applied 2017).
Event Participation	N/A	100%	Technical Potential already takes into account of event participation.

Results

Without any enabling technology, the commercial CPP program could obtain 1 MW of winter achievable potential by 2045 at $86 per kilowatt-year, as shown in Table 45. Participating customers with enabling technology can provide even more peak load reductions, and—because PSE does not pay for the existing enabling technology—they can provide the peak load reduction at a lower levelized cost, $81 per kilowatt-year.

Table 45. Commercial Critical Peak Pricing Achievable Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed	Notification Type	Levelized Cost ($/kW-year)	24-Year Achievable Potential (MW)
C&I CPP-No Enablement	10 4-hour events	Day-ahead	$86	1
C&I CPP-With Enablement	10 4-hour events	Day-ahead	$81	1

Commercial Direct Load Control Space Heat

Commercial DLC programs operate similarly to most residential DLC programs. In this commercial DLC space heat program, the utility directly reduces the electric space heating load of small and medium commercial buildings (in the office or retail segments) during event hours via load control switches. This analysis assumes four-hour events will be dispatched, with up to 10 events per winter season, using a cycling strategy of 50%. This means space heating equipment cycles off for 50% of an hour and remains on for 50% of an hour (i.e., 30 minutes off and 30 minutes on).

Program participants receive incentives at a yearly rate (though all payments may occur in the winter season), independent of the number and duration of events called. These incentives can be delivered through several applicable channels (e.g., bill credits, check incentives).

Product Options

Commercial customers in the small or medium office or retail segments with electric space heating (i.e., electric furnace or air-source heat pump) are eligible for the commercial DLC space heat program. This analysis involved two product options by eligible commercial segments:

- Small office and retail
- Medium office and retail

Input Assumptions

Table 46 lists cost and impact assumptions that Cadmus used in estimating potential and levelized costs for the commercial DLC space heat program.

Table 46. Commercial Direct Load Control Space Heat Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	Assuming 1 FTE to set up the program.
O&M Cost	$ per participant per year	$15	Assuming annual program O&M cost is 1 FTE at $150,000 per year per 10,000 small/medium commercial participants.
Equipment Cost	$ per new participant	Small: $387	Small: Applied (2017) for small C&I.
		Medium: $1,128	Medium: Applied (2017) for medium C&I.
Marketing Cost	$ per new participant	Small: $69	Small: Applied (2017) midpoint of $63-$75 for small C&I.
		Medium: $83	Medium: Applied (2017) midpoint of $75-$90 for medium C&I.
Incentives (annual)	$ per participant per year	Small: $38	Small: Applied (2017) for small C&I.
		Medium: $128	Medium: Applied (2017) for medium C&I.
Incentives (one time)	$ per new participant	$0	N/A
Attrition	% of existing participants per year	5%	Consistent with residential DLC programs.
Eligibility	% of customer count (e.g. equipment saturation)	Varies by segment	The proportion of customers in small office, small retail, medium office, and medium retail with electric furnaces or air-source heat pumps (CBSA).
Peak Load Impact	kW per participant (at meter)	Small: 1.87	Applied (2017) for WA for small and medium C&I (3.72 kW), adjusted to small C&I using a ratio of HVAC capacity sizes between small and medium C&I facilities (CBSA).
		Medium: 9.16	Applied (2017) for WA for small and medium C&I (3.72 kW), adjusted to medium C&I using a ratio of HVAC capacity sizes between small and medium C&I facilities (CBSA).
Program Participation	% of eligible customers	10%	Applied (2017): 2.3% - 3.4%; Global (2011): 10%; Brattle (2016): 14%; Navigant (2015a): 1-5%; and Brattle (2014): 15-42%.

Parameters	Units	Values	Notes
Event Participation	% (switch success rate)	95%	Consistent with residential DLC programs.

Results

Table 47 presents results for the commercial DLC space heat program, which could provide 12 MW of winter load reduction by 2045, at a levelized cost of $64 per kilowatt-year for small office and retail buildings and $29 per kilowatt-year for medium office and retail buildings.

Table 47. Commercial Direct Load Control Space Heat Achievable Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed	Notification Type	Levelized Cost ($/kW-year)	24-Year Achievable Potential (MW)
Small Com DLC Heat-Switch	10 4-hour events	0-min	$64	7
Medium Com DLC Heat-Switch	10 4-hour events	0-min	$29	5

Commercial and Industrial Curtailment

For the commercial and industrial curtailment product, the utility requests that large commercial and industrial customers curtail their loads at a predetermined level for a predetermined period (i.e., the event duration). Event durations in similar programs across the country range from one hour to five hours. For this program, Cadmus assumes the event duration lasts four hours, and up to 10 events (for a total of 40 hours) could be called per season.

Participating customers execute curtailment after the utility calls the event. Customers may curtail any end-use loads to meet the curtailment agreement.[10] Although customers receive payments to remain ready for curtailment, actual curtailment requests may not occur. Therefore, this product represents a firm resource, and it assumes customers would be penalized for noncompliance. Because penalties exist, Cadmus assumes customers in the program will deliver a curtailed load that fulfills their contractual obligations 95% of the time (i.e., event participation).

Product Description

Cadmus assumes eligible participants include customers with at least 100 kW of monthly average demand in all commercial and industrial segments, excluding small office, small retail, medium office, and medium retail. The percentage of load represented by end-use customers meeting this requirement varies across commercial segments. Eligible customers can choose between two product options:

- Manual (where customers curtail loads during an event by manually turning off equipment)

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10 Cadmus assumed that participating customers could use standby generators to curtail load, similar to the assumption in Applied (2017).

- Automated (where customers install an automated control system that turns off certain pieces of equipment upon receiving the utility event dispatch signal)

Input Assumptions

Table 48 lists cost and impact assumptions that Cadmus used in estimating potential and levelized costs for the commercial and industrial curtailment program.

Table 48. Commercial and Industrial Curtailment Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	Assuming 1 FTE to set up the program.
O&M Cost	$ per kW pledged per year	$60	Based on Cadmus (2018). Applied (2017) $71/kW (including utility and vendor costs); other benchmarked values were $27/kW (Frontier 2016) and $3/kW (Idaho Power 2015), which Cadmus assumes only included utility administrative costs.
Equipment Cost	$ per new kW pledged	Manual: $0	Manual: Assuming end users have the necessary equipment to participate.
		Automated: $310	Automated: Potter (2017)'s automated demand response enablement cost for large commercial customers (>200 kW).
Marketing Cost	$ per new kW pledged	$0	Already included in vendor management costs: Cadmus (2018); Applied (2017); Cadmus (2013b); Cadmus (2015).
Incentives (Annual)	$ per kW pledged per year	$20	California utilities have incentives that range from $4/kW (SMUD 2017) to $12/kW (Christensen 2016). Incentives from non-California utilities included $10/kW (Cadmus 2018) and $20/kW (Idaho Power 2015).
Incentives (One Time)	$ per new kW pledged	$0	N/A
Attrition	% of existing participants per year	0%	N/A
Eligibility	% of segment/end-use load	Varies by segment	Eligible customer size ranges from 100kW (SDG&E 2017; PG&E 2017b) to 200kW (Cadmus' 2018 study for Snohomish County PUD; Freeman 2013). Cadmus used 100kW as the eligible customer size, consistent with PSE's 2015 study (Cadmus 2015). Eligibility percentages were calculated using PSE customer demand data (Cadmus 2015).
Peak Load Impact	% of eligible segment/end-use load	25%	Based on 2021 Plan Workbook "Inputs_Product_NRCurtailCom-Winter" peak load impact assumption. Available at: https://nwcouncil.app.box.com/s/osjwinvjiomgo7vd4uc75y16z3x9b32i/file/655869156072
Program Participation	% of eligible segment/end-use load	3%	Based on 2021 Plan Workbook "Inputs_Product_NRCurtailCom-Winter" program participation assumption. Available at: https://nwcouncil.app.box.com/s/osjwinvjiomgo7vd4uc75y16z3x9b32i/file/655869156072 Assume half of eligible participants would participate in the Manual option while the other half would participate in the AutoDR option.
Event Participation	%	Manual: 95%	Manual: Benchmarked event participation rates range from 52% (BPA 2012) to 95% (Cadmus 2018; BPA 2016; Cadmus 2015).
		Automated: 98%	Automated: Assuming higher than the manual option.

Results

As shown in Table 49, the commercial and industrial curtailment program could, by 2045, obtain 6 MW of winter achievable potential at $95 per kilowatt-year from the manual product option and a similar amount of potential at $127 per kilowatt-year from the automated product option.

Table 49. Commercial and Industrial Curtailment Achievable Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed	Notification Type	Levelized Cost ($/kW-year)	24-Year Achievable Potential (MW)
C&I Curtailment-Manual	10 4-hour events	Day-ahead (up to 2-hour-ahead)	$95	3
C&I Curtailment-AutoDR	10 4-hour events	0-min	$127	3

Residential Electric Vehicle Service Equipment

Residential EV charger demand response programs can be implemented to reduce EV charging in residential homes during peak hours. Networked level two EV chargers allow customers to better manage their EV charging and offer PSE some ability to control and track EV charging patterns.

Product Description

EV owners can charge their EVs at home, though not all are expected to have an installed level 2 charger. This study also assumes that most existing level 2 chargers are not networked. Therefore, this study focuses on EV owners that currently charge at home, but do not have a level 2 charger installed. The program would pay for the incremental cost of installing a connected level 2 charger. This study examines the potential of this program through the Residential EV DLC product option. Res EV DLC offers a financial incentive for residential EV owners to install a new networked level 2 charger and pays an annual incentive in exchange for curtailing EV charging loads during peak events. Connected level 2 chargers predominantly communicate via Wi-Fi or cellular service and can reduce 0% to 100% of output power in response to an event signal. This study assumes that events last up to four hours, for about 5 events during the winter.

Input Assumptions

Table 50 lists cost and impact assumptions that Cadmus used in estimating potential and levelized costs for the residential electric vehicle service equipment program.

Table 50. Residential Electric Vehicle Service Equipment Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	DLC: $150,000	Assuming 1 FTE to set up the program.
O&M Cost	$ per year	DLC: $150,000	Assuming 1 FTE.
Equipment Cost	$ per new participant	300	The Regional Technical Forum's researched incremental equipment cost of networked 240V level 2 charger compared to non-networked level 2 charger is $287 (Shum 2019).
Marketing Cost	$ per new participant	DLC: $30	City Light assumes this product requires higher marketing cost than the BPA assumption (Cadmus 2018a) for DLC products: $25 per new participant.

Parameters	Units	Values	Notes
Incentives (Annual)	$ per participant per year	DLC: $25	In line with incentives for residential DLC space heat and cool products.
Incentives (One Time)	$ per new participant	$0	N/A
Attrition	% of existing participants per year	5%	In line with BPA assumption (Cadmus 2018a) for DLC products.
Eligibility	% of customer count (e.g. equipment saturation)	36%	The number of EV owners is aligned with this study's assumptions for energy efficiency. The proportion of EV owners that already have a residential 240V AC level 2 charger (64%) is based on research by the Regional Technical Forum (Shum 2019).
Peak Load Impact	kW per participant (at meter)	0.34	Based on 2021 Plan Workbook "Inputs_Product_ResEVSEDLC-Winter" peak load impact assumption. Available at: https://nwcouncil.app.box.com/s/osjwinvjiomgo7vd4uc75y16z3x9b32i/file/655868985770
Program Participation	% of eligible customers	DLC: 25%	In line with assumptions for DLC products.
Event Participation	%	95%	Based on 2021 Plan Workbook "Inputs_Product_ResEVSEDLC-Winter" event participation assumption. Available at: https://nwcouncil.app.box.com/s/osjwinvjiomgo7vd4uc75y16z3x9b32i/file/655868985770

Results

As shown in Table 51, the residential electric vehicle service equipment program could, by 2045, obtain 9 MW of winter achievable potential at $361 per kilowatt-year.

Table 51. Residential Electric Vehicle Service Equipment Achievable Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed	Notification Type	Levelized Cost ($/kW-year)	24-Year Achievable Potential (MW)
Res EV DLC	10 4-hour events	Day-ahead	$361	9

Residential Behavioral

Residential behavior demand response encourages customers to save energy during peak day events through behavioral changes. Participants receive notice (via an email or automated phone message), which includes ways to save energy and reduce peak consumption. The notice is given 24 hours prior to an event. This product does not offer incentives but dispatches fewer events (for emergency use) compared to DLC products.

Product Description

This analysis modeled one product option based on benchmarked data and information from PGE's Flex Pricing and Behavioral Demand Response Pilot (Cadmus 2018c).

Input Assumptions

Table 52 lists cost and impact assumptions that Cadmus used in estimating potential and levelized costs for the residential behavioral program.

Table 52. Residential Behavioral Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	Assuming 1 FTE to set up the program.
O&M Cost	$ per kW pledged per year	$67	BPA assumption (Cadmus 2018) of $89/kW-year (or $4/participant) assumes implementing Res Behavior DR as a stand-alone product. However, Cadmus assumes it would cost $67/kW-year (or $3/participant) to add Res Behavior DR to PSE's existing energy efficiency behavioral program.
Equipment Cost	$ per new kW pledged	$0	Participants must have a device to receive messages.
Marketing Cost	$ per new kW pledged	$0	Included in O&M costs.
Incentives (Annual)	$ per kW pledged per year	$0	In line with BPA assumption (Cadmus 2018a).
Incentives (One Time)	$ per new kW pledged	$0	In line with BPA assumption (Cadmus 2018a).
Attrition	% of existing participants per year	3.2%	PGE Flex Pricing and Behavioral Demand Response Pilot (Cadmus 2018c).
Eligibility	% of segment/ end-use load	100%	Assume all residential customers will have advanced meter by 2023
Peak Load Impact	% of eligible segment/end-use load	1.2%	PGE Flex Pricing and Behavioral Demand Response Pilot (Cadmus 2018c).
Program Participation	% of eligible segment/end-use load	20%	In line with BPA assumption (Cadmus 2018a).
Event Participation	%	100%	Peak load impact percentage accounts for event participation rate.

Results

As shown in Table 53, the residential behavioral program could, by 2045, obtain 9 MW of winter achievable potential at $76 per kilowatt-year.

Table 53. Residential Behavioral Achievable Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed	Notification Type	Levelized Cost ($/kW-year)	24-Year Achievable Potential (MW)
Res Behavior DR	10 4-hour events	Day-ahead (non-dispatchable)	$76	9

Section 3. Distributed Solar PV

Technical Potential Approach

Solar PV's technical potential depends on available areas suitable for PV installation and the power density of increasingly efficient PV arrays. Cadmus assessed these factors using the methods that follow.

Available Roof Area

We calculated the available roof area based on building square footage (RBSA[11] and CBSA[12]), number of floors (obtained from the CBSA), and a count of PSE customers. By dividing the overall square footage of each building category (single-family residential, K-12 school, etc.) by the number of floors, we estimated the roof area available for each type of building, as shown in Table 54. The estimated number of floors is an average, based on the number of floors reported by facility owners participating in the survey, rather than archetypal examples of each building type.

Table 54. Available Roof Area by Building Type

Building Type	Building Unit Floor Area (Square Feet)	Estimated Floors	Roof Area per Unit (Square Feet)	Customers in 2045
Large Office	229,882	12.0	19,085	2,708
Medium Office	41,759	3.1	13,404	11,599
Small Office	4,798	1.6	3,071	85,972
Extra Large Retail	280,351	1.4	196,246	139
Large Retail	94,426	1.4	66,098	537
Medium Retail	13,333	1.4	9,412	5,588
Small Retail	2,170	1.3	1,655	7,042
School K-12	36,550	1.6	23,100	3,458
University	121,328	1.6	76,679	2,599
Warehouse	34,314	1.5	22,529	6,957
Supermarket	49,734	1.3	37,300	1,749
Mini-Mart	2,116	1.1	1,996	1,202
Restaurant	9,727	1.2	8,447	8,772
Lodging	31,385	4.9	6,341	1,851
Hospital	80,979	2.0	39,803	366
Residential Care	89,214	2.0	43,851	358
Assembly	13,631	2.0	6,667	3,705
Other	22,415	2.0	10,964	19,507
Total Commercial				**164,109**
Single Family	1,284	1.6	934	752,283
Single Family Low Income	1,284	1.6	934	136,417
Multifamily Low Rise			371	231,646
Multifamily Low Rise Low Income			371	74,929
Multifamily High Rise			227	42,211
Multifamily High Rise Low Income			227	13,654
Manufactured	1,269	1.0	1,446	59,938

11 RBSA 2018 dataset of PSE oversample.

12 Based on CBSA 2014 data of all utilities within the "urban" subset.

Building Type	Building Unit Floor Area (Square Feet)	Estimated Floors	Roof Area per Unit (Square Feet)	Customers in 2045
Manufactured Low Income	1,269	1.0	1,446	33,158
Total Residential				**1,344,234**

Adjusted Available Area

The available raw area cannot be used directly to estimate technical potential because not every roof is suitable for solar PV. To account for factors such as unsuitable roof orientation, shading, and obstructions, Cadmus relied on PSE's 2017 assessment of potential that utilized Light Detection and Ranging (LIDAR) data from the National Renewable Energy Laboratory's (NREL's) rooftop solar PV technical potential study and filtered it to match PSE's service territory. In addition, Cadmus applied a reduction in available roof area due to Washington's adoption of the 2012 International Fire Code (IFC) Article 605.11.3, which requires that the minimum roof area be maintained for safe access by emergency personnel.[13] An addendum requires that PV arrays "shall be located no higher than 18 inches (457 mm) below the ridge in order to allow for fire department rooftop operations."[14] Although this is less stringent than similar codes adopted in California and other jurisdictions, it nevertheless limits the available roof area for installing PV modules. Cadmus estimated this would reduce the available square footage by 5% for residential applications. Table 55 provides the estimated technical constraints applied to each sector.

Table 55. Technical Constraints Assumptions by Sector

Sector/Building Type	Technical Constraints Assumptions
Residential	26% based on LIDAR data and IFC Article 605.11.3
Commercial	51% based on LIDAR data and IFC Article 605.11.3

Module Power Density

Cadmus determined the average module power density in the PSE region through a review of installed PV system data provided by PSE. Using model number lookups for modules installed in 2018 and 2019, we determined the 2018 average module watts per square foot. Cadmus estimated future module power density using the trends in module efficiency increases from the International Roadmap for Photovoltaic. [15] Module power density in 2018 was 17.3 W_p/square foot, the estimated power density in 2022 is 18.5 W_p/square foot and the estimated power density in 2045 is 21.1 W_p/square foot.

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13 Washington State Department of Enterprise Services, State Building Code. https://fortress.wa.gov/ga/apps/sbcc/Page.aspx?nid=14

14 Ibid.

15 International Technology Roadmap for Photovoltaic. https://itrpv.vdma.org/web/itrpv/download

Electricity Generation

Once the potential solar PV direct current capacity was established, we converted this figure into annualized electricity (kilowatt-hour) generation. To approximate the generation profile of a typical PV system in PSE's service territory, Cadmus calculated an average capacity factor in kWh/kW_{DC} from the PSE's 2020 solar production database. The result is an average electricity generation figure, normalized to installed capacity, which accounts for specific regional characteristics for PSE's service territory.

Achievable Potential Approach

After calculating the technical potential that provides a theoretical upper bound on PV capacity growth, Cadmus considered relevant market factors (e.g., current costs, projected future cost trends, past adoption) to determine likely PV growth for PSE's service territory. To assess achievable potential, Cadmus first examined sector, end-use load, and customer economics for PV adoption in terms of simple payback. We applied these metrics to calculate achievable potential for two policy-based scenarios, considering the impacts of federal tax credits, incentives, and policies. The examination included the following scenarios:

- **Business-as-Usual Scenario.** This scenario reflects the base case with all current policies and incentives locked in place as written, including incentive amounts, expiration dates, and similar characteristics. Although this may not represent the most realistic scenario, this can provide a strong baseline for considering policy alternatives and planning scenarios. This includes several key policies:
  - Federal Investment Tax Credit: The ITC provides a 30% PV tax credit through 2019, with 26% in 2020, 22% in 2021, and expiring on December 31, 2021 for residential PV but reduced to 10% for commercial building PV thereafter.
  - Washington State Sales Tax Exemption: Solar PV equipment was exempt from a 6.5% Washington State Sales Tax. This benefit expired on September 30, 2017 and is not included in the business-as-usual scenario.
  - Washington State Renewable Energy System Cost Recovery Program (Production Incentive): The Production Incentive provided a variable, production-based incentive up to $5,000 per year for PV systems. The incentive level ranged from $0.15/kWh to $0.54/kWh, depending on the customer's eligibility for a variety of incentive adders (e.g., using equipment manufactured in Washington). PSE terminated this incentive December 12, 2019 and it is also not included in this study.
- **Advanced Cost Decline Scenario.** This scenario models a more rapid rate of cost decline while maintaining all the same financial incentives as the Business-as-Usual scenario. The cost decline is based on NREL's 2020 Annual Technology Baseline's[16] (ATB) advanced cost forecast compared to the moderate cost forecast used in the business-as-usual scenario.

[16] NREL provides an annual set of modeling input assumptions for energy technologies, known as the Annual Technology Baseline, including residential and commercial PV. Available online: https://atb.nrel.gov

Customer payback. A metric commonly used in selling energy efficiency and renewable energy technologies, annualized simple payback (ASP) is a simplistic calculation that customers can easily and intuitively understand and provides a key factor in their financial decision-making processes. For this analysis, Cadmus calculated simple payback using the following equation:

$$ASP = \frac{Net\ Costs\ (after\ incentives)}{Annual\ Energy\ Savings + Production\ Incentive\ Payments - Annual\ O\&M}$$

Although this equation is conceptually simple, the mix of incentives and cost projections added complexity to the calculations.

Installed costs. Cadmus based these assumptions of installed PV system costs on a variety of public data sources. Cadmus reviewed cost forecasts of both residential and commercial solar installations. These costs do not include any incentives, they are based on full costs of an installation. The PV $/Watt cost estimates for this study were developed from three major sources:

- 2020 EnergySage reported costs for installed residential solar PV systems in Washington state[17]
- 2020 Wood Mackenzie U.S. Solar Market Insight Full Report, 2019 Year in Review for nation-wide commercial solar PV systems[18]
- 2020 NREL ATB forecasts for residential- and commercial-scale PV pricing estimates to 2050[19]

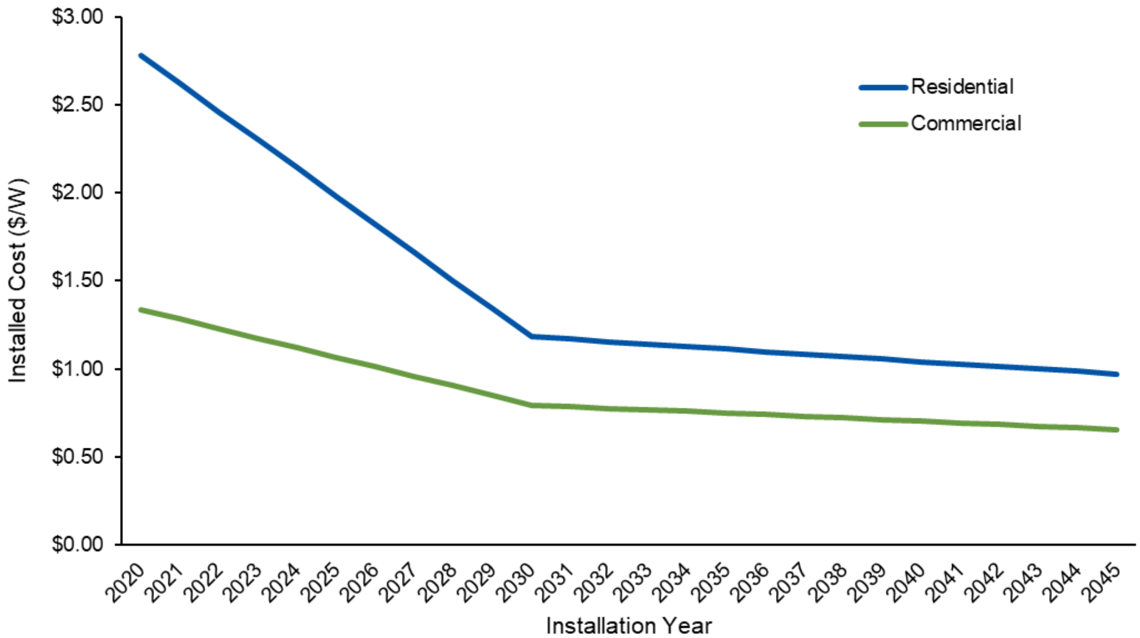
Cadmus used a combination of these sources to validate and forecast $/watt. The projected installed dollar per watt is shown in Figure 42 over the planning horizon.

17 EnergySage is an online marketplace for residential solar installations that gathers real quotes from installers. This online marketplace was used to validate solar prices. EnergySage available online: https://www.energysage.com/solar-panels/solar-panel-cost/wa/

18 Wood Mackenzie, U.S. Solar Market Insight Full Report, 2019 Year in Review, March 2020. Available online: https://www.woodmac.com/reports/power-markets-us-solar-market-insight-2019-year-in-review-395500

19 NREL provides an annual set of modeling input assumptions for energy technologies, known as the Annual Technology Baseline, including residential and commercial PV. Available online: https://atb.nrel.gov

Figure 42. Projected Installed PV Costs by Sector (2020-2045)



Market penetration rates. Predicting which portion of technically feasible sites will install PV systems during the assessment period is a complex process, driven by many policy, economic, and technical factors beyond the direct control of PSE. These factors can be effectively modeled using their impacts on a quantitative metric (such as customer simple paybacks) and run for a variety of prototypical scenarios. This model estimates (a percentage of) market penetration as a function of customer payback. The following equation provided the curve used in analysis:

$$MP = A * e^{-B*ASP}$$

where MP equals the percentage of market adoption, and ASP equals the annual simple payback (years).

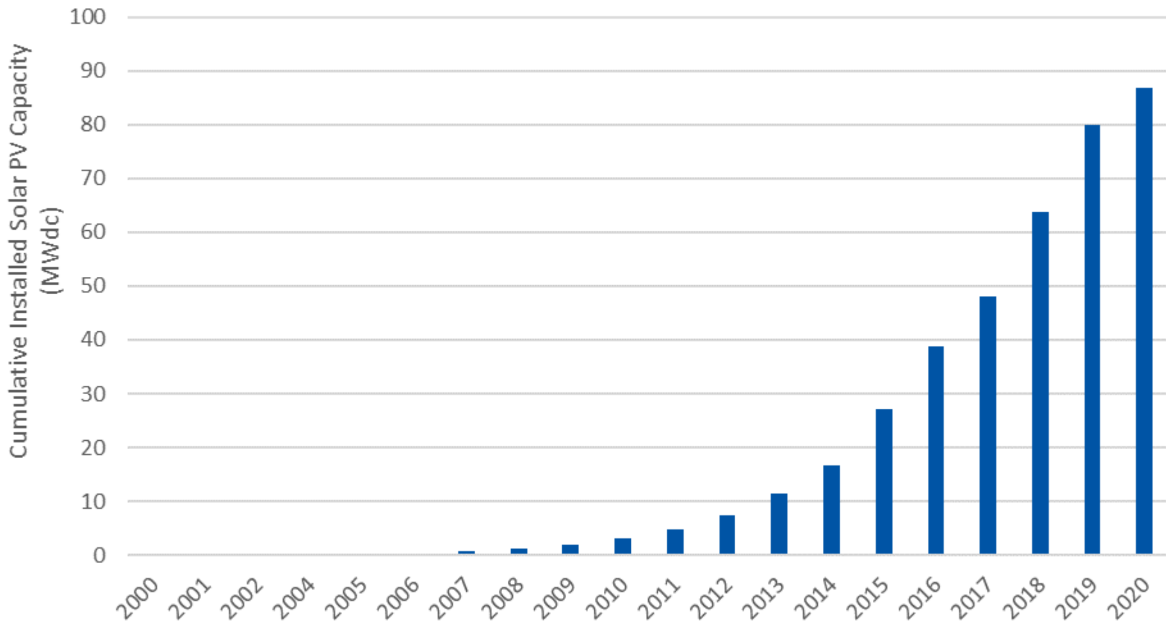
For this analysis, Cadmus calculated ASP from the end-use customers' perspectives, including all relevant incentives and fitting the curve to historical adoption rates. This curve-fitting process allowed Cadmus to account for, broadly speaking, regional attitudes and bias that might lead end-use customers to adopt solar at a given ASP level (the above equation shows these empirical factors as A and *B).*

After running the two scenarios of the plausible ranges in achievable potential, Cadmus relied on the base scenario to represent most realistic and current rate adoption. We used hourly profiles based on NREL's PVWatts calculator for the residential, commercial, and industrial sectors combined with the achievable base scenario potential to determine the PSE's IRP 8760 inputs.

Historical Solar PV Installations

As previously noted, the study estimated solar PV market potential for new installations from 2022 through 2045. This potential is in addition -- not inclusive of – the amount of solar PV capacity previously installed by customers in PSE's service territory. Figure 43 provides the cumulative installed solar PV capacity from 2000 through the first six months of 2020. Overall, the cumulative installed capacity is equal to 87 MW_{dc}. Nearly 60 MW, or 69% of the total, have been installed since 2016.

Figure 43. Historical Solar PV Installed Capacity, MW_{dc} through 2020



Distributed Solar PV Potential

Technical Potential Results

Based on the analysis described in the previous sections, Cadmus estimated 22,330 MW as the total new technical potential for PV installed on residential and commercial rooftops in PSE's service area over the 24 year study horizon. 71% of this technical potential arose in the commercial sector with the remaining 29% came from the residential sector. Each sector's technical potential is a function of the fraction of total roof area available and the total roof area. In this case, the residential sector accounted for a smaller percentage of the technical potential because only a modest proportion of total available area for this sector is likely to be suitable for PV installations. If the full technical potential were installed, it would generate approximately 2,362 aMW. This estimate derives from specific capacity factors for PSE (0.117 for residential and commercial), calculated using PSE's 2020 solar production database.

Table 56 provides the study period behind-the meter PV technical potential with growth due to increases in building stock from 2022 to 2045.

Table 56. PV Technical Potential (2022-2045)

Sector	Total 2022 aMW	Installed Capacity 2022 MW	Total 2045 aMW	Installed Capacity 2045 MW
Residential	534	4,560	697	6,584
Commercial	1,305	11,142	1,665	15,746

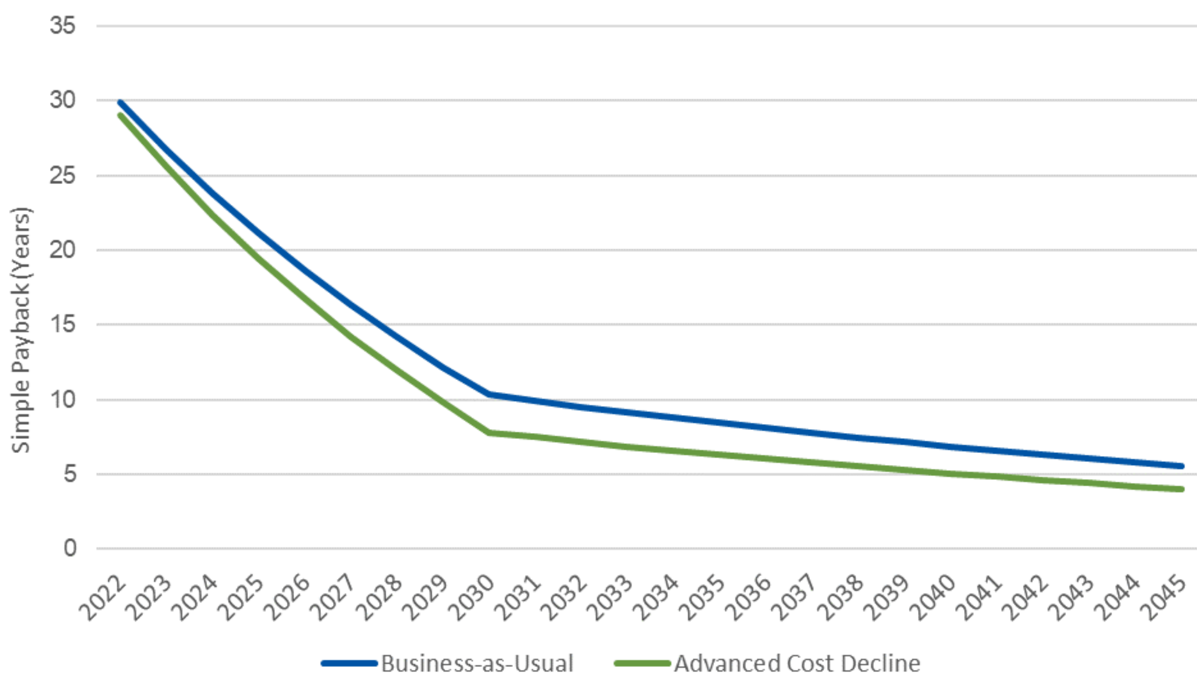
Sector	Total 2022 aMW	Installed Capacity 2022 MW	Total 2045 aMW	Installed Capacity 2045 MW
Total	**1,840**	**15,701**	**2,362**	**22,330**

Achievable Potential Results

Historically, the PV market has been heavily influenced by policy and incentive decisions, but, over time, future incentives may play a lesser role. For example, projects continue to be completed in California, even though major incentives have ended, and more projects continue to be completed under the Federal Public Utility Regulatory Policies Act. To model the influence of this policy shift away from incentives on the PV market potential within PSE's territory, Cadmus developed two scenarios reflecting the impact of only changes in upfront capital costs on customer paybacks and, by extension, market potentials. Unsurprisingly, the rate of decline in system capital cost heavily influences PV's achievable potential. In this section, Cadmus summarizes the results for each scenario (the business-as-usual and the advanced cost decline scenario).

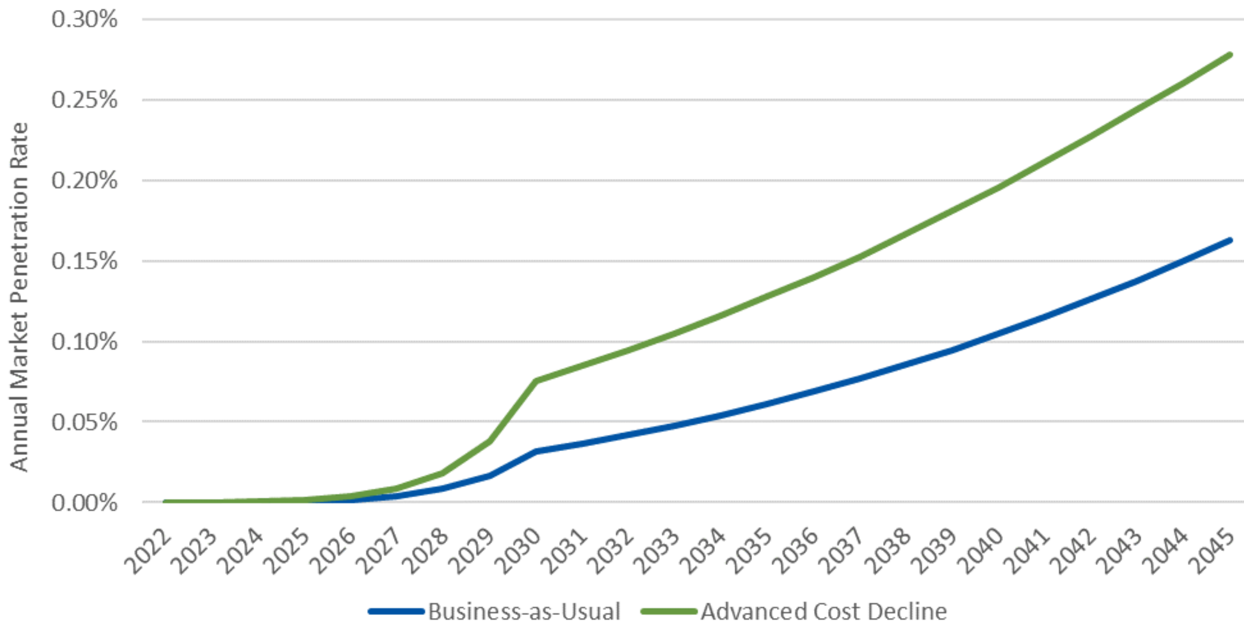
Figure 44 shows the impact of these scenario choices on expected customer payback periods (residential). The business-as-usual scenario shows a payback period of 30 years at the beginning of the study period and dropping to 6 years by 2045 primarily due to lower capital costs. The advanced cost decline scenario drops from a 29-year payback period in 2022 to 4 years in 2045.

Figure 44. Residential PV Simple Payback Projections Under Two Policy Scenarios



As a result, these varying payback periods have an impact on the likely adoption of PV systems. As discussed in the PV Achievable Potential Approach, Cadmus modeled a percentage of market penetration as a function of customer payback. Figure 45 shows the annual market penetration rate for the residential sector of each adoption scenario. Having lower PV costs is a major driver to increased market adoption.

Figure 45. Residential PV Annual Market Penetration Rate Under Two Policy Scenarios



Overall, across PSE's service area (residential and commercial), achievable potential will grow steadily year by year under both adoption scenarios, as shown in Figure 46. The advanced cost decline scenario results in achievable technical potential in 2045 of over 1.8 times that of the business-as-usual scenario.

Figure 46. Solar PV Total Cumulative Achievable Potential by Scenario

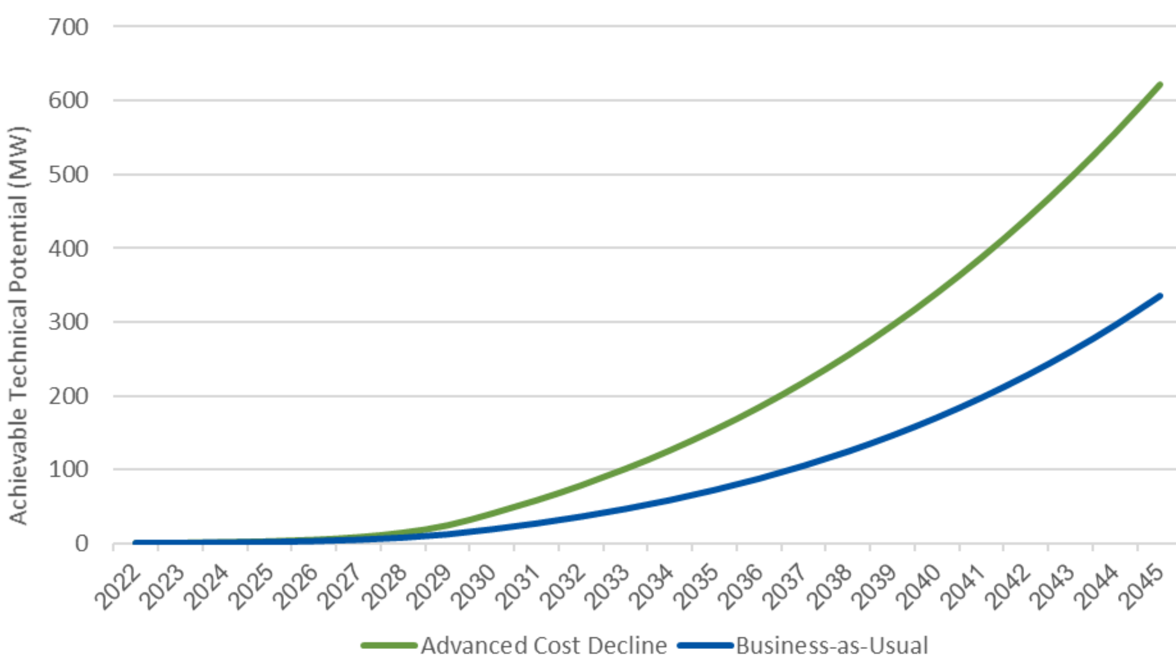


Table 57 summarizes the achievable potential results for each scenario. Cadmus relied on the business-as-usual scenario to represent the most realistic adoption rate for the IRP.

Table 57. Achievable Potential Results by Scenario and Sector, 2045 MW

Scenario	Residential MW	Commercial MW	Total MW
Business-as-Usual	87	249	336
Advanced Cost Decline	165	457	622

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Appendix A. IRP Sensitivities

This appendix provided comparisons of various electric and natural gas IRP sensitivies to the base case potentials presented throughout this report.

Electric IRP Sensitivities

Following engagements with stakeholders, PSE requested Cadmus to create four additional sensitivity scenarios for electric measures. The scenarios included are:

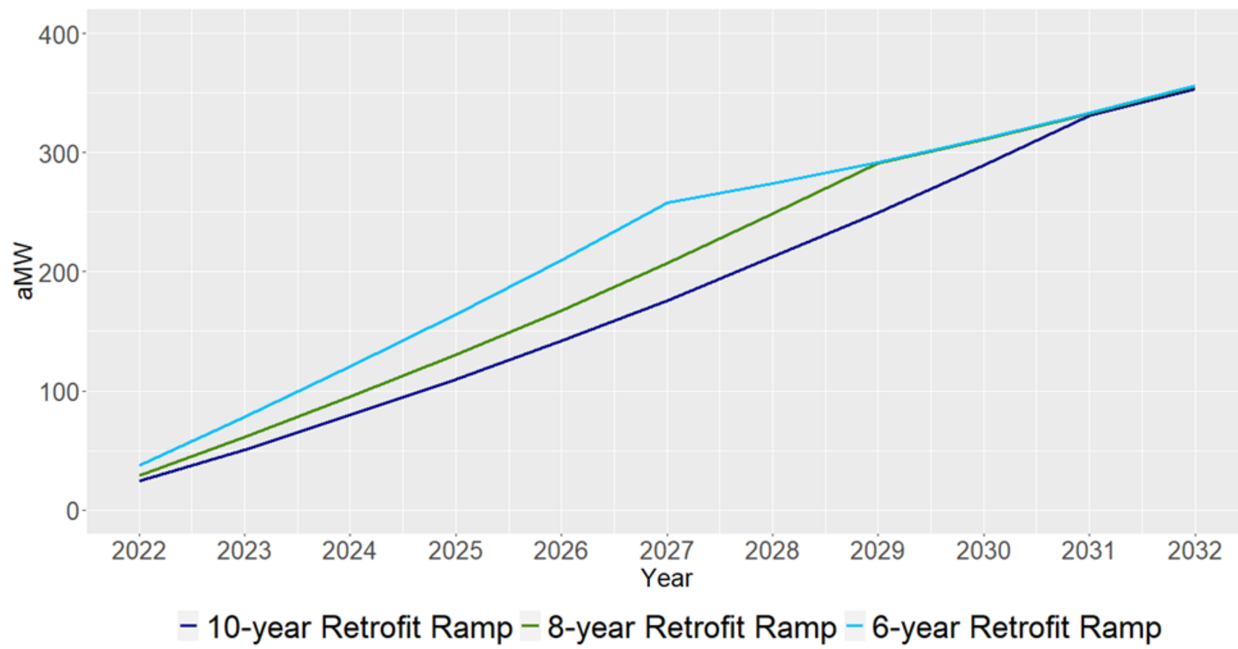
- **The 6-Year Retrofit Ramp Scenario** estimates potential using an accelerated ramp rate for discretionary measures, so all discretionary potential is obtained in the first 6 years of the study.
- **The 8-Year Discretionary Ramp Scenario** estimates potential using an accelerated ramp rate for discretionary measures, so all discretionary potential is obtained in the first 8 years of the study.
- **Societal Discount Rate Adjusted Scenario** utilizes a discount rate of 2.5%.
- **Non-energy Impact Adjusted Scenario** calculates the non-energy impact based on the EPA estimate for the cost of non-energy impacts of $0.02/kWh. [20]

Cadmus compared the results of these scenarios to the base scenario, with a 10-year retrofit ramp rate, to determine the impact of the scenarios on overall electric energy efficiency achievable potential.

Figure A-1 shows the impact of the differing ramp rate scenarios on the distribution of the cumulative energy efficiency achievable potential over the first ten years of the potential study.

[20] The Environmental Protection Agency estimates the per kWh non-energy benefits to be 2 cents for the PNW region.

Figure A-1. 10-Year Cumulative Energy Efficiency Achievable Potential (aMW)



The differing ramp rates for discretionary measures result in 43% of the 24-year electric achievable energy efficiency potential being achieved in the first 6 years and 48% of the 24-year electric achievable energy efficiency potential being achieved in the first 8 years**.** It is important to note that the 24-year cumulative electric achievable energy efficiency potential is equivalent across all scenarios and the differing ramp rates only have an impact on the distribution of the potential within the potential study horizon.

Table A-1 provides a comparison of the 6-year cumulative achievable potential from the base scenario with a 10-year retrofit ramp rate to the scenario with a 6-year retrofit ramp rate.

Table A-1. Comparison of 6-Year Electric Energy Efficiency Cumulative Achievable Potential for IRP Sensitivity Ramp Rate Scenarios (aMW)

Year	10-year Retrofit Ramp Achievable Potential (aMW)	6-year Retrofit Ramp Achievable Potential (aMW)	Percent Change Compared to 10-year Retrofit Ramp
2027	176.09	257.59	46.3%

In the first 6 years of the potential study, 176 aMW of cumulative achievable potential is obtained in the base scenario. In the 6-year retrofit ramp rate scenario, the cumulative achievable potential in the first six years is 46% greater with a value of 256 aMW.

Table A-2 provides a comparison of the 8-year cumulative achievable potential from the base scenario with a 10-year retrofit ramp rate to the scenario with an 8-year retrofit ramp rate.

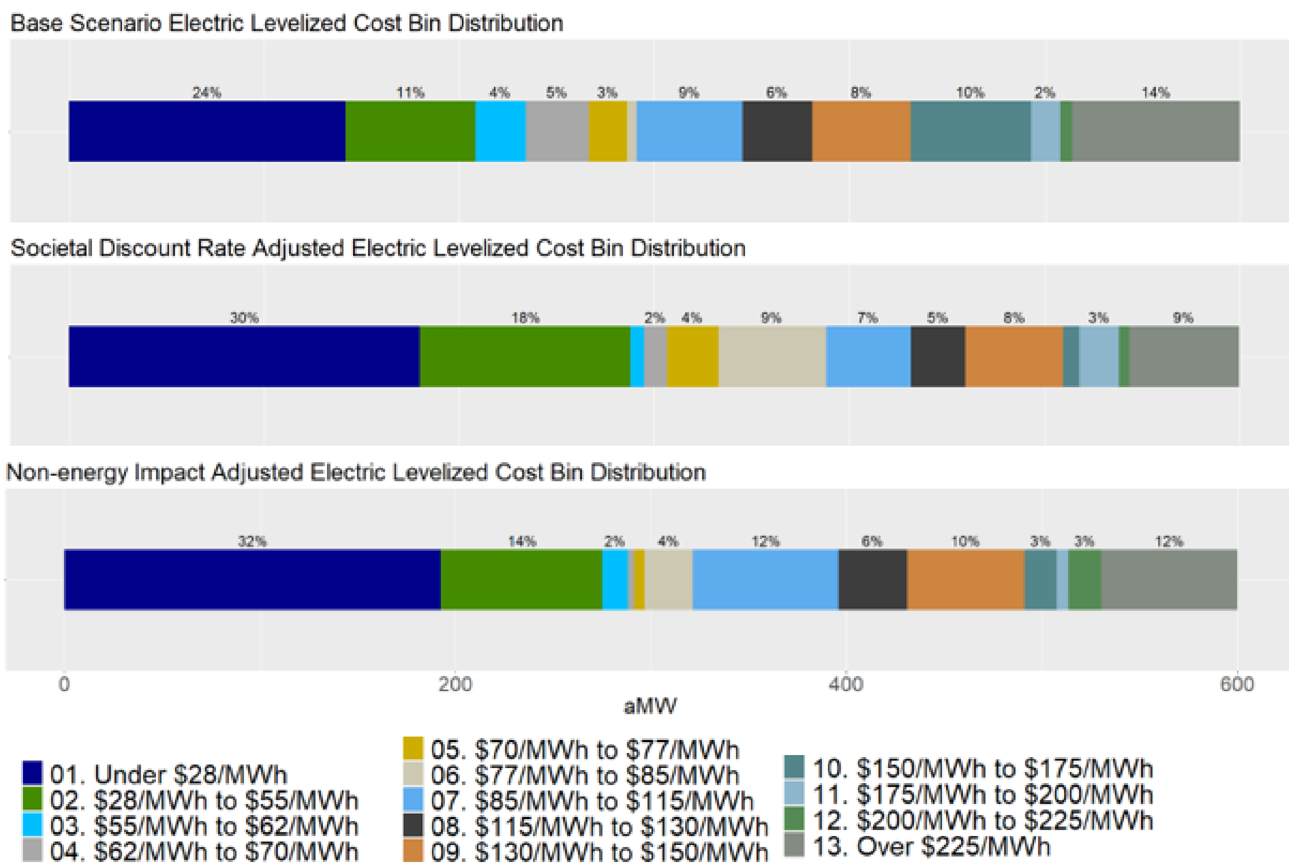
Table A-2. Comparison of 8-Year Electric Energy Efficiency Cumulative Achievable Potential for IRP Sensitivity Ramp Rate Scenarios (aMW)

Year	10-year Retrofit Ramp Achievable Potential (aMW)	8-year Retrofit Ramp Achievable Potential (aMW)	Percent Change Compared to 10-year Retrofit Ramp
2029	249.68	290.86	16.5%

In the first 8 years of the potential study, 250 aMW of cumulative achievable potential is obtained in the base scenario. In the 8-year retrofit ramp rate scenario, the cumulative achievable potential in the first eight years is 17% greater with a value of 291 aMW.

Figure A-2 shows the impact of the societal discount rate adjusted scenario and the non-energy impact adjusted on the electric levelized cost bin distribution when compared to the base scenario. Note that the base scenario has a discount rate of 6.8%.

Figure A-2. Comparison of Levelized Cost Bin Distribution for 24-Year Cumulative Achievable Potential in IRP Sensitivity Scenarios (aMW)



The non-energy impact adjusted scenario and the societal discount rate adjusted scenario have 13% and 11%, respectively, more of the 24-year cumulative electric achievable potential with a levelized cost under $55/MWh. This equates to about 80 and 67 more aMW, respectively, of 24-year cumulative achievable potential than the base scenario under $55/MWh. Additionally, in the societal discount rate adjusted and the non-energy benefit adjusted scenarios, the cost bin designated by a levelized cost greater than $225/MWh is reduced by 56 aMW and 69 aMW, respectively, and is no longer the second largest bin.

Gas IRP Sensitivities

PSE requested Cadmus to create four additional sensitivity scenarios for natural gas measures. The scenarios included are:

- **The 6-Year Retrofit Ramp Scenario** estimates potential using an accelerated ramp rate for discretionary measures, so all discretionary potential is obtained in the first 6 years of the study.
- **The 8-Year Discretionary Ramp Scenario** estimates potential using an accelerated ramp rate for discretionary measures, so all discretionary potential is obtained in the first 8 years of the study.
- **Societal Discount Rate Adjusted Scenario** utilizes a discount rate of 2.5%.

Cadmus compared the results of these scenarios to the base scenario, with a 10-year retrofit ramp rate, to determine the impact of the scenarios on overall natural gas energy efficiency achievable potential.

Figure A-3 shows the impact of the differing ramp rate scenarios on the distribution of the cumulative energy efficiency achievable potential over the first ten years of the potential study.

Figure A-3. 10-Year Cumulative Energy Efficiency Achievable Potential (Therms)

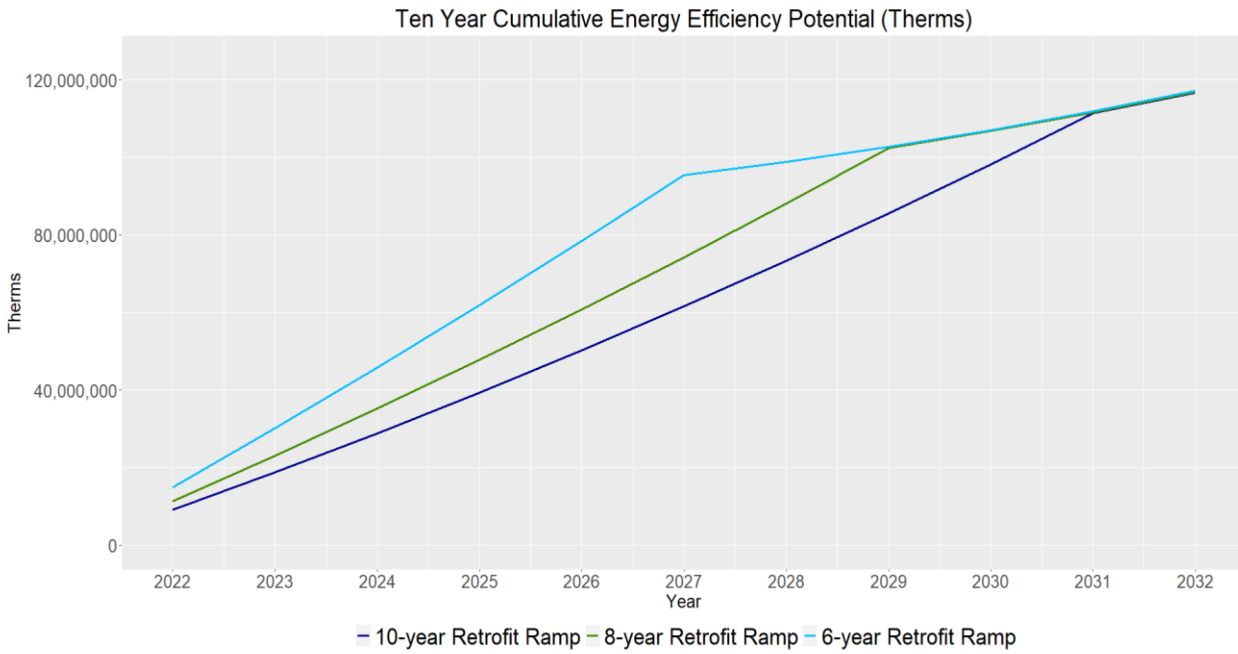


Table A-3 provides a comparison of the 6-year cumulative achievable potential from the base scenario with a 10-year retrofit ramp rate to the scenario with a 6-year retrofit ramp rate.

Table A-3. Comparison of 6-Year Natural Gas Energy Efficiency Cumulative Achievable Potential for IRP Sensitivity Ramp Rate Scenarios (Therms)

Year	10-year Retrofit Ramp Achievable Potential (Therms)	6-year Retrofit Ramp Achievable Potential (Therms)	Percent Change Compared to 10-year Retrofit Ramp
2027	61,576,169	95,411,744	54.9%

In the first 6 years of the potential study, 61.6 million therms of cumulative achievable potential are obtained in the base scenario. In the 6-year retrofit ramp rate scenario, the cumulative achievable potential in the first six years is 54.9% greater with a value of 95.4 million therms.

Table A-4 provides a comparison of the 8-year cumulative achievable potential from the base scenario with a 10-year retrofit ramp rate to the scenario with an 8-year retrofit ramp rate.

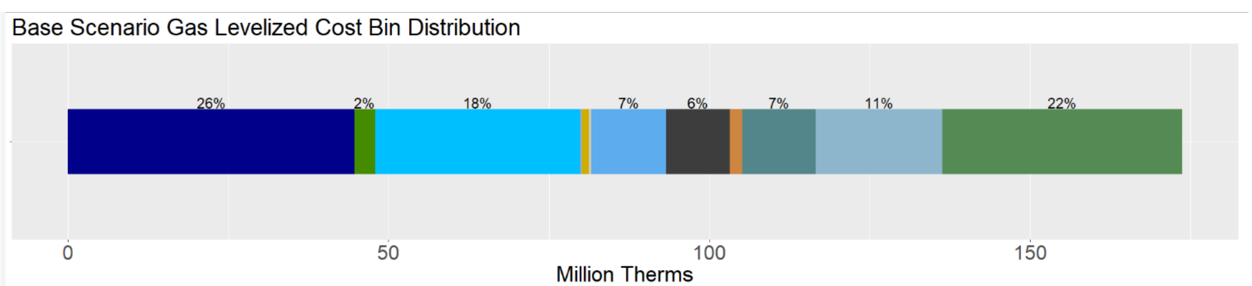
Table A-4. Comparison of 8-Year Natural Gas Energy Efficiency Cumulative Achievable Potential for IRP Sensitivity Ramp Rate Scenarios (Therms)

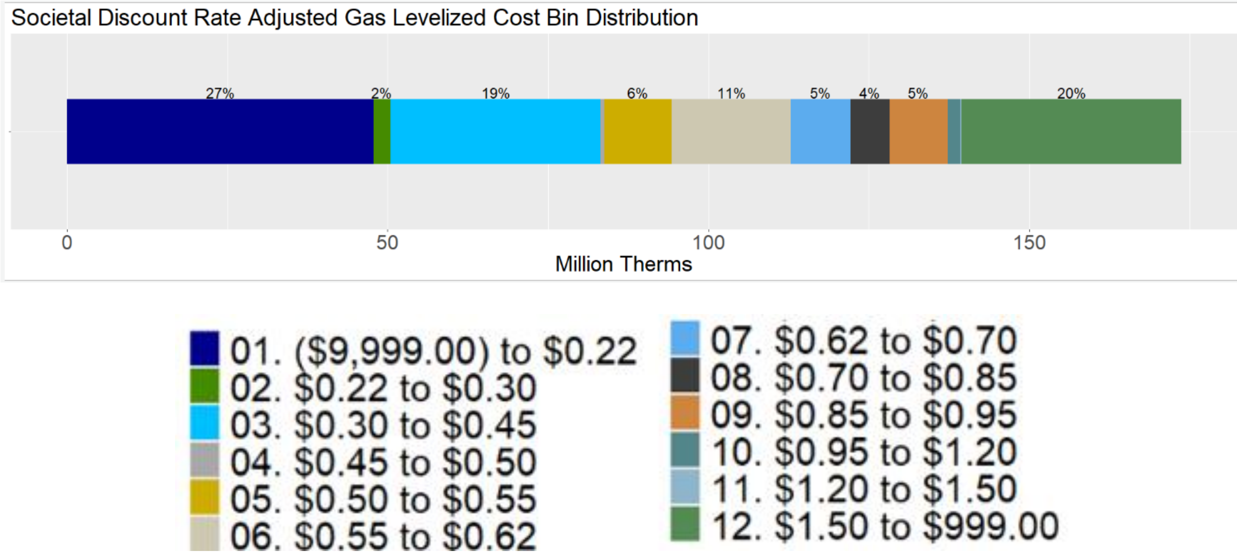
Year	10-year Retrofit Ramp Achievable Potential (Therms)	8-year Retrofit Ramp Achievable Potential (Therms)	Percent Change Compared to 10-year Retrofit Ramp
2029	85,553,452	102,425,509	19.7%

In the first 8 years of the potential study, 85.6 million therms of cumulative achievable potential is obtained in the base scenario. In the 8-year retrofit ramp rate scenario, the cumulative achievable potential in the first eight years is 19.7% greater with a value of 102.4 million therms.

Figure A-4 shows the impact of the societal discount rate adjusted scenario on the natural gas levelized cost bin distribution when compared to the base scenario. Note that the base scenario has a discount rate of 6.8%. When the societal discount rate is used the amount of cumulative 20-year achievable potential in the least expensive cost bin increases by one percent and the highest cost bin potential decreases by a percent compared to the base scenario. The greatest change in levelized cost bin distribution occurs across cost bins five to eleven (levelized costs $0.50 - $1.50). In the societal discount rate scenario, there is more cumulative achievable potential in the lower of these cost bins compared to the base scenario.

Figure A-4. Comparison of Levelized Cost Bin Distribution for 20-Year Cumulative Achievable Potential in IRP Sensitivity Scenarios (Million Therms)





Cost bins that make up less than 2% of the 20-Year Cumulative Achievable Potential are not labeled on the horizontal bar charts

Appendix B. Gas-to-Electric Potential Scenario

Executive Summary

Public policies that are intended to make the transition of energy product and end use away from fossil fuels are affecting electric and gas utilities across the country, including in California, New York, Rhode Island, Massachusetts, and Minnesota. The new Washington State Clean Energy Transformation Act (CETA), Senate Bill 5116-2019-20, enacted May 2019, lays out the utility requirements for making the transition to 100% greenhouse gas-neutral generation by 2030.

This new policy, as well as other possible policies affecting gas use in Washington state, could have a direct impact on the electric system needs as well as the customers of Puget Sound Energy (PSE). For the purpose of supporting IRP decarbonization scenario analysis, Cadmus modeled a gas-to-electric conversion scenario that investigates PSE's electric system load impacts and customer costs of PSE customer conversions from natural gas to electric end uses from 2022 through both 2030 and 2045.

Cadmus used data from the 2021 conservation potential assessment (CPA), PSE customer database, the PSE Residential Characteristics Survey (RCS), the Commercial Building Stock Assessment (CBSA), and other sources to calculate these potential impacts. Cadmus also conducted additional research to determine cost and load impacts of some equipment types.

Table B-1 shows the cumulative annual electric energy impacts to PSE's system of converting natural gas equipment for each customer sector. As shown in the table, the biggest impact in 2030 and 2045 is in the residential sector, which accounts for 53% and 60% of the total cumulative energy impacts in 2030 and 2045, respectively. These impacts represent additional electric energy loads of 7.9% and 35.5% compared to the total PSE electric load forecast in 2030 and 2045, respectively.

Table B-1. Cumulative Annual Electric Energy Impacts in 2030 and 2045, MWh

Sector	2030	2045
Residential	996,501	3,517,799
Commercial	666,018	1,826,011
Industrial	111,319	252,763
Total	**1,773,837**	**5,596,573**

The energy impacts presented in Table B-1 and throughout Appendix B represent energy impacts at generation, thereby accounting for transmission and distribution line losses from the generator to the customer meter. The study assumed a line loss rate of 6.8% for all customer classes.

Table B-2 presents the cumulative annual winter peak demand impacts to PSE's system of converting natural gas equipment for each customer sector. The commercial and residential sectors contribute 63% and 33% of the 2030 peak demand increase, respectively, but by 2045, the residential sector accounts for 68% of the total peak demand increase compared to 30% from the commercial sector. Combined, these impacts represent additional electric peak demands of 6% and 17% in 2030 and 2045, respectively.

Table B-2. Cumulative Annual Electric Peak Demand Impacts in 2030 and 2045, MW

Sector	2030	2045
Residential	207	708
Commercial	108	311
Industrial	13	29
Total	**328**	**1,048**

Table B-3 shows the cumulative annual impacts of converting natural gas equipment to electric for each customer sector. The values in the table represent the cumulative natural gas throughput reductions from the gas-to-electric conversions. The residential sector accounts for 68% and 73% of the total natural gas reductions in 2030 and 2045, respectively.

Table B-3. Cumulative Annual Natural Gas Impacts in 2030 and 2045, Therms

Sector	2030	2045
Residential	-167,979,794	-636,439,120
Commercial	-75,375,044	-225,596,733
Industrial	-2,857,517	-6,487,974
Total	**-246,212,356**	**-868,523,827**

The natural gas reductions in Table B-3 represent a decrease of 21% and 74% in 2030 and 2045, respectively, compared to PSE's total 2019 natural gas sales. Similar to the CPA, the gas to electric conversion scenario developed for the IRP does not include PSE's commercial or industrial gas transport customers. The next section of Appendix B describes the methods employed by Cadmus to estimate the gas-to-electric conversion potential.

Methods

Cadmus calculated the energy, peak demand, and cost impacts of converting natural gas to electric equipment within PSE's natural gas service territory. Because PSE's natural gas service territory includes not only PSE electric customers but also electric customers of Seattle City Light, Snohomish County Public Utility Department (PUD), Tacoma Power, and Lewis County PUD, PSE natural gas customer conversions to electric end uses will inevitably affect these other utilities' electric systems. However, for the purpose of this IRP and this gas to electric scenario, our electric energy and peak demand potential estimates apply only to PSE's electric service territory and exclude the impacts on other electric utilities.

We applied different analytical approaches for the residential and commercial sectors than for the industrial sector. For the residential and commercial sectors, we counted the number of natural gas equipment units in PSE's service area and applied the energy, demand, and cost impacts to these units. In the industrial sector, our approach involved a top-down method. We calculated the total industrial gas load and then converted these loads into electric energy and peak demand.

Residential and Commercial Sectors

Cadmus calculated the number of natural gas equipment units that could be converted to electric equipment in PSE's service area for both existing equipment and new construction. We took PSE's customers counts and forecasts and applied equipment saturation rates and fuel shares in each year of the study horizon (2022–2045) plus a base year (2021). We then matched each natural gas unit to an equivalent electric equipment and applied annual energy consumption, peak demand, and cost assumptions to the electric equipment to calculate the total impact of conversion. Figure B-1 shows the calculation methodology applied to the residential and commercial sectors.

Figure B-1. Residential and Commercial Impacts Calculation Methodology

To mitigate the peak demand impacts of additional winter space heating loads to the electric system, the Cadmus team modeled existing residential construction natural gas furnace replacements assuming the use of a hybrid air-source heat pump with natural gas backup that switches from electric space heating to natural gas when the outdoor air temperature is equal to or less than 35 degrees Fahrenheit. To estimate annual electric impacts, we relied on a similar stock turnover algorithm as was used in the CPA, where it is assumed that baseline equipment is replaced at a rate of one divided by the equipment's effective useful life. In other words, for end use equipment with a 10-year measure life, 10% (1/10) of the existing equipment stock is replaced in a given year.

In addition to the stock turnover algorithm, potential impacts of natural gas to electric conversions were constrained by the rate at which assumed baseline (natural gas) equipment would be replaced by electric equipment. For example, the study assumed that heat pump technologies, including hybrid heat pumps with gas backup and heat pump water heaters, would achieve a market replacement rate of 50% in 2030 and 100% by 2045. In other words, of all the gas furnaces in existing residential homes modeled to reach the end of their useful life in 2030, the scenario assumed half of these would be replaced by hybrid heat pump units, while the remaining half would be replaced by gas furnaces. Over time, the study assumed a linear increase from roughly 5% replacements in the first year, to 50% by 2030, and 100% by 2045 for heat pump technologies. Using a similar methodology as the CPA, Cadmus assumed that existing gas furnace replaced with gas furnaces would remain eligible for replacement with hybrid units later in the study horizon once the replacement unit's effective useful life expires.

Residential and Commercial Data Sources

Cadmus used PSE customer counts and forecasts, residential equipment saturation and fuel share data from PSE's 2017 Residential Customer Survey (RCS), commercial equipment saturation data from the 2021 PSE CPA, and the 2014 CBSA to estimate gas equipment counts. Cadmus used PSE's current CPA to determine the energy impacts of equipment conversion. To assess the peak demand impacts, Cadmus used each equipment's hourly end-use profile and combined these with PSE's high load hour definition to determine the coincident peak impacts. Table B-4 lists the data sources used to analyze conversion impacts in the residential and commercial sectors.

Table B-4. Data Sources for the Residential and Commercial Analysis

Analysis Component	Data Sources
Residential, Commercial, and Industrial Customer Counts	2020 PSE customer counts, PSE customer forecasts
Residential Equipment Fuel Shares and Saturations	2017 RCS
Commercial Equipment Fuel Shares and Saturations	2014 CBSA
Residential Electric Equipment Consumption	2021 PSE CPA
Commercial Electric Equipment Consumption	2021 PSE CPA
Residential Electric Equipment Peak Demand	2021 PSE CPA, end use load shapes
Commercial Electric Equipment Peak Demand	2021 PSE CPA, end use load shapes
Residential Electric Equipment Costs	2021 PSE CPA, Cost research (RSMeans and online research)
Commercial Electric Equipment Costs	2021 and 2015 PSE CPA, Cost research (RSMeans and online research)

Equipment Counts

Cadmus used 2020 PSE customer counts to estimate the number of natural gas equipment units that would be converted to electric equipment. We projected the 2020 customer counts for the 24 years of the study horizon (2022-2045) plus a base year (2021) using PSE's forecast growth estimates. Cadmus used customer growth forecasts to calculate the effects of new construction that did not involve gas connections.

To calculate the number of non-electric equipment units, Cadmus applied equipment fuel shares and saturations to the PSE customer counts at the segment level. We first calculated the number of customers in each residential and commercial customer segment then applied segment-specific fuel shares and equipment saturations.[21] Our analysis also accounted for the proportion of natural gas customers with existing cooling equipment to avoid overestimating the cooling load from new heat pump equipment.

Residential Electric Equipment Impact Calculations and Assumptions

Cadmus counted equipment units for these residential natural gas furnaces, boilers, water heaters, clothes dryers, and cooking equipment. We then applied the energy, peak demand, and costs of similar electric equipment to calculate impacts across the service area. Residential heating equipment costs include the costs to upgrade a home's electric panel to accommodate new electric heating equipment.

To replace a natural gas forced air furnace, Cadmus added an additional cost to account for decommissioning the old equipment and venting, line sets, duct work and pad, and any new required electrical outlets (i.e. 220 volt circuits).[22] These additional costs equaled about $2,088 for single family homes, which account for 92% of PSE's existing customer homes with natural gas service.

Table B-5 shows the range of assumptions we used to calculate the energy, demand, and cost impacts of converting the various residential natural gas equipment types to electric equipment for each customer segment. The second column of the table shows the relevant electric equipment we assumed would replace the natural gas equipment. Other columns show the various energy (kWh), demand (kW), and cost metrics we applied to calculate the total system impacts.

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[21] Residential segments include single-family, multifamily, and manufactured homes. Commercial segments include assembly, hospital, large office, large retail, lodging, medium office, medium retail, minimart, other, restaurant, school K-12, small office, small retail, supermarket, warehouse, extra-large retail, residential care, and university.

[22] Cost data based on RSMeans 2019 (https://www.rsmeans.com/) and online services that assess construction costs in the Seattle area (i.e., homewyse.com, homeadvisor.com, homeguide.com, inchcalculator.com). These costs include installation and materials such as panels, wires, and conduit at the existing panel location. This study does not account for existing wire upgrades and panel placement per code requirements or varying permit fees in different jurisdictions.

Table B-5. Residential Equipment Energy, Peak Demand, and Cost Assumptions

Natural Gas Equipment	Electric Equipment	Construction	Annual kWh	Winter kW	Incremental Cost
Furnace	Hybrid Heat Pump	Existing	1,805 to 4,359	0.38 to 0.91	$1,874 to $10,874
Furnace	Heat Pump – Cold Climate	New	2,715 to 6,213	0.69 to 1.58	-$407 to $8,757
Boiler	Ductless Heat Pump	Existing, New	2,331 to 5,946	0.54 to 1.38	-$2,693 to $4,518
Clothes Dryer	Clothes Dryer	Existing, New	922	0.13	$117
Cooking	Cooking	Existing, New	178	0.03	-$510
Tank Water Heater	Heat Pump Water Heater	Existing, New	995 to 1844	0.019 to 0.36	$1,454
Tankless Water Heater	Heat Pump Water Heater	Existing, New	995 to 1844	0.019 to 0.36	$815

As shown in Table B-5, the incremental costs show a negative cost impact for some new construction applications. The baseline condition includes natural gas heating equipment (e.g., furnaces and boilers) as well as portion of buildings with electric cooling equipment. As a result, the baseline costs of the heating and cooling (e.g., furnaces and boilers with cooling systems) costs more than the converted electric equipment installations.

Commercial Electric Equipment Impact Calculations and Assumptions

For the commercial sector, Cadmus counted equipment units for natural gas furnaces, boilers, commercial cooking equipment, and water heating. We then calculated the energy, peak demand, and cost impacts of converting this equipment by applying the electric energy consumption, peak demand, and costs of similar electric equipment.

Table B-6 shows the assumptions we used to calculate the energy, demand, and cost impacts of converting the various natural gas equipment types to electric equipment. The second column shows the relevant electric equipment we assumed would replace the natural gas equipment. Other columns show the energy (kWh), demand (kW), and cost metrics we applied to calculate the total system impacts. The table provides values on a per building basis and the ranges represent the diversity of the commercial building stock. The commercial cooking equipment end use includes a number of equipment options (e.g., fryer, broilers, steamers, conventional ovens, and convection ovens); therefore, to minimize the complexity of the scenario analysis, we assessed commercial cooking loads in aggregate.

Table B-6. Commercial Equipment Energy, Peak Demand, and Cost Assumptions

Natural Gas Equipment	Electric Equipment	Construction	Annual kWh	Winter kW	Incremental Cost
Furnace	Hybrid Heat Pump	Existing, New	1,625 to 264,039	0.34 to 55.18	$17,418 to $232,245
Furnace	Heat Pump – Cold Climate	Existing, New	444 to 376,364	0.18 to 118.82	$13,315 to $177,227
Boiler	Heat Pump	Existing, New	444 to 242,805	0.18 to 76.66	$9,443 to $198,299
Cooking	Cooking	Existing, New	4,176 to 79,151	0.53 to 10.74	$0 to $10,079
Tank Water Heater	Heat Pump Water Heater	Existing, New	429 to 161,812	0.06 to 21.68	-$4,541 to $7,899

Industrial Sector

Similar to the 2021 CPA, Cadmus used a top-down method to estimate the new electric industrial load. We calculated the total industrial non-electric space heating load by proportioning 2019 industrial customer natural gas sales using data from PSE's 2021 CPA. We did not evaluate natural gas process loads for this study and focused only on space heating equipment. Depending on the industrial segment, the natural gas space heating load as a percentage of total facility load ranged from 0% (fruit storage) to 55% (miscellaneous manufacturing).

Overall, industrial natural gas space heating load presented about 34% of the natural gas load. This study assumed all space heating load can be converted to electric equipment such as electric resistance, electric boilers, and heat pumps. This analysis would represent the upper end of the space heating load that can be converted and, as a result, Cadmus limited the convertible industrial gas load to 30%.

To convert the non-electric space heating equipment into electric space heating equipment, Cadmus applied equipment coefficients of performance ratios and converted the non-electric MMBtu into electric kWh. For simplicity, we assumed a non-electric coefficient of performance of 0.80 (i.e., similar to federal standards for boiler and furnace thermal efficiency requirements) and electric coefficient of performance of 1.20. The electric equipment coefficient of performance assumes a mix of equipment including heat pumps.

The industrial analysis included one base scenario and did not evaluate multiple efficiency scenarios. It should be noted, the customer forecast of industrial customer declines from year to year. Therefore, the industrial load analysis applied only to existing construction conversion scenario. As noted previously, Cadmus also excluded industrial gas transport customers from this analysis.

Load Impacts

Cadmus assessed the electric load impacts of PSE customers' conversion of natural gas to electric equipment from 2022 through 2045. We calculated these load impacts in terms of energy and winter and summer peak demand. We also calculated the energy and peak impacts by end use.

Electric Energy Impacts

Table B-7 shows the energy impacts by sector and end use group of converting natural gas to electric equipment in 2030 and 2045. Within the residential sector, air source heat pumps – applied only to new construction – and hybrid heat pumps (considered only for existing construction applications) combined for over 500,000 MWh of incremental cumulative load through 2030 and more than 1.6 million MWh by 2045. Conversion of natural gas water heating to electric heat pump water heaters accounted for approximately 271,0000 MWh of incremental load cumulative through 2030 and more than 1.1 million MWh by 2045.

Table B-7. Sector and End Use Cumulative Annual Electric Energy Impacts in 2030 and 2045, MWh

Sector	End Use	2030	2045
Residential	Heat Pump	316,606	766,057
	Hybrid	196,845	898,333
	Water Heat	270,778	1,160,318
	Other	212,271	693,091
	Residential Sub-total	**996,501**	**3,517,799**
Commercial	Heat Pump	47,035	151,455
	Hybrid	84,854	276,997
	Water Heat	69,010	214,360
	Other	465,118	1,183,199
	Commercial Sub-total	**666,018**	**1,826,011**
Industrial	**Industrial Sub-total**	111,319	252,763
Total	**Total**	**1,773,837**	**5,596,573**

The other end use loads listed in Table B-7 include cooking, dryers, and residual space heating loads not directly accounted for when comparing the bottom-up calculations of end use saturations and loads to the overall PSE natural gas forecast. Examples of these residual loads include secondary gas heating sources, including secondary furnaces, fireplaces, hearths, and additional gas use including but not limited to outdoor cooking and pool heating. As a simplifying assumption, Cadmus assumed conversion of these natural gas to electric loads using the hybrid heat pump conversion factor, which equated to roughly 8.6 kWh/therm.

Peak Demand Impacts

Cadmus calculated the peak demand impacts in PSE's total service area as shown in Table B-8, which provides the winter and summer peak demand impacts by sector and end use group of converting natural gas to electric equipment in 2030 and 2045. The residential sector accounted for 63% of the total new winter peak demands through 2030 and 68% through 2040.

Table B-8. Sector and End Use Cumulative Annual Electric Demand Impacts in 2030 and 2045, MW

Sector	End Use	Winter		Summer	
		2030	2045	2030	2045
Residential	Heat Pump	81	195	45	109
	Hybrid	41	188	27	125
	Water Heat	44	190	28	115

Sector	End Use	Winter		Summer	
		2030	2045	2030	2045
	Other	42	136	13	43
	Residential Sub-total	**207**	**708**	**114**	**393**
Commercial	Heat Pump	16	51	1	3
	Hybrid	29	94	2	6
	Water Heat	10	30	7	21
	Other	54	137	50	128
	Commercial Sub-total	**108**	**311**	**60**	**158**
Industrial	Other	13	29	13	29
Total	**Total**	**328**	**1,048**	**186**	**580**

Natural Gas Reduction Impacts

In addition to the impacts from natural gas to electric conversions on PSE's electric system, Cadmus also calculated the associated natural gas throughput reductions at the equipment, end use, and sector levels. Table B-9 shows the cumulative sector and end use natural gas reductions through 2030 and 2045. The largest impacts occurred within the residential sector and, more specifically, its space heating end uses. Overall the residential sector accounted for 68% and 73% of the cumulative 2030 and 2045 natural gas reductions, respectively, while accounting for approximately 54% and 56% of PSE's baseline forecast sales without decarbonization in 2030 and 2045.

Table B-9. Sector and End Use Cumulative Annual Natural Gas Reductions in 2030 and 2045, therms

Sector	End Use	2030	2045
Residential	Space Heat	-94,830,995	-366,996,249
	Water Heat	-44,122,297	-143,784,672
	Other	-29,026,503	-125,658,200
	Residential Sub-total	**-167,979,794**	**-636,439,120**
Commercial	Space Heat	-34,419,512	-111,892,867
	Water Heat	-11,232,973	-35,016,824
	Other	-29,722,559	-78,687,042
	Commercial Sub-total	**-75,375,044**	**-225,596,733**
Industrial	Other	-2,857,517	-6,487,974
Total	**Total**	**-246,212,356**	**-868,523,827**

The values in Table B-9 are negative to reflect that the natural gas to electric scenario results in natural gas throughput reductions.

Calculate Levelized Costs

To incorporate the gas to electric scenario results in PSE's IRP scenario, Cadmus developed levelized cost estimates for the natural gas reductions, which PSE modeled comparably to energy efficiency. The potential is grouped by levelized cost over a 24-year period the natural gas reductions. The 24-year natural gas levelized-cost calculations incorporate numerous factors, which are shown in Table B-10.

Table B-10. Levelized Cost Components

Type	Component
Costs	Incremental Measure Cost
	Administrative Adder
	Present Value of T&D Deferrals*

*For natural gas, this includes the deferred gas distribution benefits

Cadmus did not incorporate the costs associated with additional electric energy loads or the need to potentially acquire new generation or to expand the existing transmission and distribution to meet the new electric peak demands as PSE's IRP model accounts for these variables.

In addition to the upfront capital cost and annual energy savings, the levelized-cost calculation incorporates several other factors, consistent with the Council's methodology:

- ***Incremental measure cost.*** This study considers the costs required to sustain savings over a 24-year horizon, including reinstallation costs for measures with useful lives less than 24 years. If a measure's useful life extends beyond the end of the 24-year study, Cadmus incorporates an end effect that treats the levelized cost of that measure over its EUL as an annual reinstallation cost for the remainder of the 24-year period.[23,24]
- ***Incremental operations and maintenance (O&M) benefits or costs.*** As with incremental measure costs, O&M costs are considered annually over the 24-year horizon. The present value is used to adjust the levelized cost upward for measures with costs above baseline technologies and downward for measures that decrease O&M costs.
- ***Administrative adder.*** Cadmus assumed a program administrative cost equal to 20% of incremental measure costs for electric and gas measures across all sectors.

Compared with energy efficiency, Cadmus did not incorporate any non-energy benefits, the regional 10% conservation adder, or secondary energy benefits in the gas to electric levelized cost calculations.

[23] In this context, EUL refers to levelizing over the measure's useful life. This is equivalent to spreading incremental measure costs over its EUL in equal payments assuming a discount rate equal to PSE's weighted average cost of capital (6.80%).

[24] This method is applied both to measures with a useful life of greater than 24 years and measures with a useful life that extends beyond study horizon at time of reinstallation.

F

Demand Forecasting Models

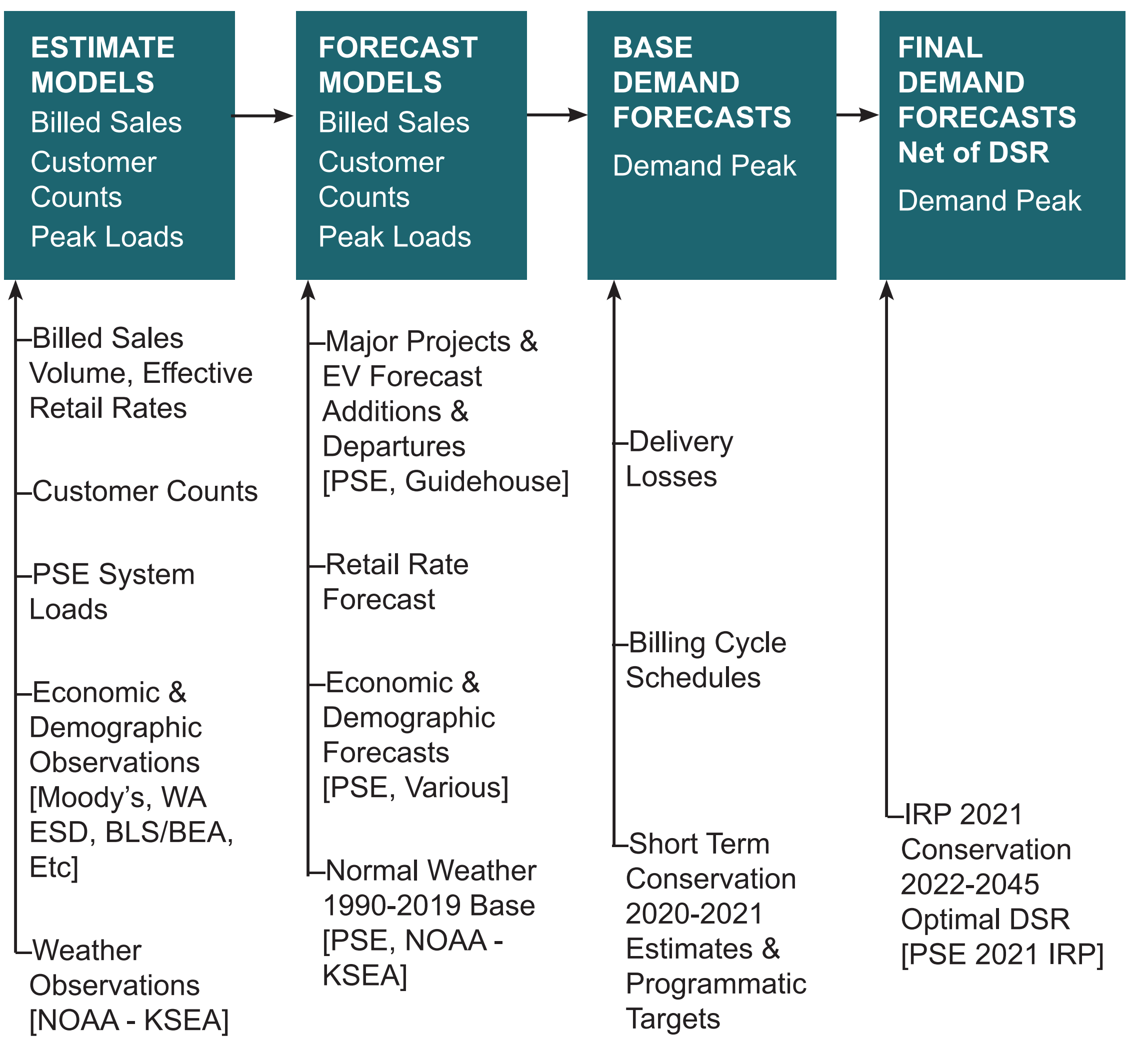
This appendix describes the econometric models used in creating the demand forecasts for PSE's 2021 IRP analysis.

Contents

1. THE DEMAND FORECAST

PSE employs time series econometric methods to forecast monthly energy demand and peaks for PSE's electric and natural gas service territories. PSE gathers observations of sales, customer counts, demand, weather and economic/demographic variables to estimate models of use per customer (UPC), customer counts and peaks. Once model estimation is complete, PSE utilizes internal and external forecasts of new major demand (block sales), retail rates, economic/demographic drivers, normal weather and programmatic conservation to create a 20-year projection of monthly demand and peaks. The 2021 IRP Base Demand Forecast for energy reflects committed, short-term programmatic conservation targets; the 2021 IRP Base Demand net of demand-side resources (DSR) additionally reflects the optimal DSR chosen in the 2021 IRP analysis. The following diagram depicts the demand forecast development process:

Figure F-1: Demand Forecast Development Process Flow



Model Estimation

To capture incremental customer growth and temperature/economic sensitivities, PSE forecasts billed sales by estimating use per customer (UPC) and customer count models. The models are disaggregated into the following major classes and sub-classes (or sectors, as determined by tariff rate schedule) in order to best estimate the specific driving forces underlying each class.

- Electric: residential, commercial (high-voltage interruptible, large, small/medium, lighting), industrial (high-voltage interruptible, large, small/medium), streetlights and resale
- Natural gas: firm classes (residential, commercial, industrial, commercial large volume and industrial large volume), interruptible classes (commercial and industrial) and transport classes (commercial firm, commercial interruptible, industrial firm and industrial interruptible).

Each class's historical sample period ranges from, at earliest, January 2003 to December 2019.

> > > See Chapter 6, Demand Forecasts, *for discussion of the development of economic/demographic input variables.*

Customer Counts

PSE estimates monthly customer counts by class and sub-class. These models use explanatory variables such as population, employment (both total and sector specific), and unemployment. Larger customer classes are estimated via first differences, with economic and demographic variables implemented in a lagged or polynomial distributed lag form to allow delayed variable impacts. Some smaller customer classes are not estimated, and instead held constant. ARMA(p,q) error structures are also imposed, subject to model fit.

The estimating equations for **customer counts** are specified as follows:*

$$CC_{C,t} = \boldsymbol{\beta_C}\left[\propto_C \quad \boldsymbol{D}_{M,t} \quad T_{C,t} \quad \boldsymbol{ED}_{C,t}\right] + u_{C,t},$$

where:

Customer Count ("$CC_{C,t}$")	=	Count of customers in Class/sub-class "C" and month "t"
Class ("C")	=	Service and class/sub-class, as determined by tariff rate
Time ("t")	=	Estimation time period
Regression Coefficients ("$\boldsymbol{\beta_C}$")	=	Vector of CC_C regression coefficients estimated using Conditional Least Squares/ARMA methods
Constant ("$\propto_C$")	=	Indicator variable for class constant (if applicable)
Date Indicator ("$\boldsymbol{D}_{M,t}$")	=	Vector of month/date specific indicator variables
Trend ("$T_{C,t}$")	=	Trend variable (not included in most classes)
Economic/Demographic Variables ("$\boldsymbol{ED}_{C,t}$")	=	Vector of economic and/or demographic variables
Error term ("$u_{C,t}$")	=	ARMA error term (ARMA terms chosen in model selection process)

** The term vector or boldface type denotes one or more variables in the matrix.*

Use Per Customer

Monthly use per customer (UPC) is estimated at class and sub-class levels using explanatory variables including degree days, seasonal effects, retail rates, average billing cycle length, and various economic and demographic variables such as income and employment levels. Some of the variables, such as retail rates and/or economic variables, are modelled in a lagged form to account for both short-term and long-term effects on energy consumption. Finally, depending on the equation, an ARMA(p,q) error structure is employed to address issues of autocorrelation. The estimating equations for **use per customer** are as follows:*

$$\frac{UPC_{C,t}}{D_{c,t}} = \boldsymbol{\beta_C}\left[\propto_C \quad \frac{\boldsymbol{DD}_{C,t}}{D_{C,t}} \quad \boldsymbol{D}_{M,t} \quad T_{C,t} \quad \boldsymbol{RR}_{C,t} \quad \boldsymbol{ED}_{C,t}\right] + u_{C,t}$$

where:

Use Per Customer ("$UPC_{C,t}$")	=	Billed Sales ("$Billed\ Sales_{C,t}$") divided by Customer Count ("$CC_{C,t}$"), in class "C", month "t"
Cycle Days ("$D_{C,t}$")	=	Average number of billed cycle days for billing month "t" in class "C"
Regression Coefficients ("$\boldsymbol{\beta_C}$")	=	Vector of UPC_C regression coefficients estimated using Conditional Least Squares/ARMA methods
Constant ("$\propto_C$")	=	Indicator variable for class constant (if applicable)
Degree Days ("$\boldsymbol{DD}_{C,t}$")	=	Vector of weather variables. Calculated value that drives monthly heating and/or cooling demand.

$$\boldsymbol{HDD}_{C,Base,t} = \sum_{d=1}^{Cycle_t} |max(0, Base\ Temp - Daily\ Avg\ Temp_d)| * BillingCycleWeight_{C,d,t}$$

$$\boldsymbol{CDD}_{C,Base,t} = \sum_{d=1}^{Cycle_t} |max(0, Daily\ Avg\ Temp_d - Base\ Temp)| * BillingCycleWeight_{C,d,t}$$

Date Indicator ("$\boldsymbol{D}_{M,t}$")	=	Vector of month/date specific indicator variables
Trend ("$T_{C,t}$")	=	Trend variable (not included in most classes)
Effective Retail Rates ("$\boldsymbol{RR}_{C,t}$")	=	The effective retail rate. The rate is smoothed, deflated by a Consumer Price Index, and interacted with macroeconomic variables and/or further transformed.
Economic and Demographic Variables ("$\boldsymbol{ED}_{C,t}$")	=	Vector of economic and/or demographic variables
Error term ("$u_{C,t}$")	=	ARMA error term

** The term vector or boldface type denotes one or more variables in the matrix.*

Peak Electric Hour and Natural Gas Day

The electric and natural gas peak demand models relate observed monthly peak system demand to monthly weather-normalized delivered demand. The models also control for other factors, such as observed temperature, exceptional weather events, day of week, or time of day.

The primary driver of a peak demand event is temperature. In winter, colder temperatures yield higher demand during peak hours, especially on evenings and weekdays. The peak demand model uses the difference of observed peak temperatures from normal monthly peak temperature and month specific variables, scaled by normalized average *monthly* delivered demand, to model the weather sensitive and non-weather sensitive components of monthly peak demand. In the long-term forecast, growth in monthly weather-normalized delivered demand will drive growth in forecasted peak demand, given the relationships established by the estimated regression coefficients.

The **electric peak hour** regression estimation equation is:

$$\max\left(Hour_{1,t} \ldots Hour_{H_{t},t}\right) =$$
$$\boldsymbol{\beta}\left[\frac{Demand_{N,t}}{H_t}\boldsymbol{D}_{M,t} \quad \Delta Temperature_{N,t}\frac{Demand_{N,t}}{H_t}\boldsymbol{D}_{S,t}\boldsymbol{D}_{PeakType,t} \quad \boldsymbol{D}_{DoW,t} \quad D_{LtHr,t} \quad D_{Hol,t} \quad T_{Hot,t}\right] + \varepsilon_t$$

where:

Hourly Demand (“$Hour_{J,t}$”)	=	Hourly PSE system demand (MWs) for hour j=1 to $H_{t,}$
Total Hours (“H_t”)	=	Total number of hours in a month at time “t”
Regression Coefficients (“$\boldsymbol{\beta}$”)	=	Vector of electric peak hour regression coefficients
Normalized Demand (“$Demand_{N,t}$”)	=	Normalized total demand in month at time “t”
Temperature Deviation (“$\Delta Temperature_{N,t}$")	=	Deviation of actual peak hour temperature from *hourly* normal minimum peak temperature
Month Indicator (“$\boldsymbol{D}_{M,t}$”)	=	Vector of monthly date indicator variables
Month Indicator (“$\boldsymbol{D}_{S,t}$”)	=	Vector of seasonal date indicator variables
Peak Type (“$\boldsymbol{D}_{PeakType,t}$”)	=	Vector of heating or cooling peak indicators
Day of Week Indicator (“$\boldsymbol{D}_{DoW,t}$”)	=	Vector of Monday, Friday, and Mid-Week indicators
Evening Peak (“$D_{LtHr,t}$”)	=	Indicator variable for evening winter peak
Winter Holiday (“$D_{Hol,t}$”)	=	Indicator variable for holiday effects
Cooling Trend (“$T_{Hot,t}$”)	=	Trend to account for summer air conditioning saturation
Error term (“ε_t”)	=	Error term

Similar to the electric peaks, the natural gas peak day is assumed to be a function of weather and non-weather-sensitive delivered demand, the deviation of actual peak day average temperature from normal daily average temperature in a month, and type of days.

The **natural gas peak day** estimation equation is:

$$\max\left(Day_{1,t} \dots Day_{Days_{t},t}\right) = \boldsymbol{\beta}[BDemand_{N,t} \quad \Delta Temperature_{N,t} HDemand_{N,t} \quad \boldsymbol{D}_{M,t} \quad \boldsymbol{D}_{WE,t}] + \varepsilon_t$$

where:

Daily Demand (“$Day_{i,t}$”)	=	Firm delivered dekatherms for day “i”
Total Days (“$Days_{t}$,”)	=	Total number of days in a month at time “t”
Regression Coefficients (“$\boldsymbol{\beta}$”)	=	Vector of gas peak day regression coefficients

Normalized Firm Heating Demand (“$HDemand_{N,t}$”) = Normalized monthly firm delivered heating demand

Normalized Firm Base load Demand (“$BDemand_{N,t}$”) = Normalized monthly firm delivered base load demand

Temperature Deviation (“$\Delta\, Temperature_{N,t}$”)	=	Deviation of observed daily average temperature from the normal minimum temperature for that month
Month Indicator (“$\boldsymbol{D}_{M,t}$”)	=	Vector of monthly date indicator variables
Weekend Indicator (“$\boldsymbol{D}_{WE,t}$”)	=	Vector of date specific indicator variables
Error term (or “ε_t”)	=	Error term

The natural gas peak day equation uses monthly normalized firm delivered demand as an explanatory variable, and the estimated model weighs this variable heavily in terms of significance. Therefore, the peak day equation will follow a similar trend as that of the monthly firm demand forecast with minor deviations based on the impact of other explanatory variables. An advantage of this process is that it uses demand of distinct natural gas customer classes to help estimate gas peak demand.

Billed Sales Forecast

To forecast billed sales, PSE uses the UPC and customer count models derived above with external and internally derived forecast drivers. Economic, demographic and retail rate forecasts, as well as "normal" monthly degree days, are fitted with model estimates to create the 20-year use per customer and customer count projections by class. The class total billed sales forecasts are formed by multiplying forecasted use per customer and customers ($\widehat{UPC}_{C,t} * D_{C,t} * \widehat{CC}_{C,t}$), then adjusting for known future discrete additions and subtractions ("$Block\ Sales_{C,t}$").

Major block sales changes are incorporated as additions or departures to the sales forecast as they are not reflected in historical trends covered in the estimation sample period. Examples of such items include emerging electric vehicle (EV) demand, large greenfield developments, changes in usage patterns by large customers, fuel and schedule switching by large customers, or other infrastructure projects. Finally, for the IRP Base Demand Scenario, the forecast of billed sales is reduced by new programmatic conservation ("$Conservation_{C,t}$") by class, using established conservation targets in 2020-2021.

The total **billed sales forecast** equation by class and service is:

$$Billed\ Sales_{C,t} = \widehat{UPC}_{C,t} * D_{C,t} * \widehat{CC}_{C,t} + Block\ Sales_{C,t} - Conservation_{C,t}$$

Where:

Time ("t")	=	Forecast time horizon
Use Per Customer ("$\widehat{UPC}_{C,t}$")	=	Forecast use per customer
Cycle Days ("$D_{C,t}$")	=	Average number of scheduled billed cycle days for billing month "t" in class "C"
Customer Count ("$\widehat{CC}_{C,t}$")	=	Forecast count of customers
Conservation ("$Conservation_{C,t}$")	=	Base Scenario: Ramped/shaped programmatic conservation targets
Major New Sales ("$Block\ Sales_{C,t}$")	=	Ramped/shaped expected entering or exiting sales not captured as part of the customer count or UPC forecast.

Total billed sales in a given month are calculated as the sum of the billed sales across all customer classes:

$$Total\ Billed\ Sales_t = \sum_c Billed\ Sales_{c,t}$$

Base Demand and Final Demand Net of DSR Forecasts

Demand

Total system demand is formed by distributing monthly billed sales into calendar sales, then adjusting for company own use and losses from distribution, and for electric only, transmission. The electric and natural gas demand forecasts ("$\widehat{Demand}_{N,t}$") form the 2021 IRP Electric and Natural Gas Base Demand Forecasts. For the IRP Final Demand scenario, the optimal conservation bundle is found in the 2021 IRP.

Peak Demand

PSE forecasts peak demand using the peak models estimated above, plus assumption of normal design temperatures, forecasted total system normal demand less conservation ("$\widehat{Demand}_t - Conservation_t$"), and short-term forecasted peak conservation targets. Peak conservation and demand conservation are distinct: they are related, however, different conservation measures may have larger or small impacts on peak when compared with energy. Thus, the peak models seek to reflect exact peak conservation assumption from programmatic activities and the previous Conservation Potential Assessment, as opposed to simple downstream calculations from demand reduction. These calculations yield system hourly peak demand each month based on normal design temperatures.

$$Peak\ Demand_t = F\left(\widehat{Demand}_{t,}, \Delta Temperature_{N,Design,t}\right) - Conservation_{Peak,t}$$

Where:

$Peak\ Demand_t$	=	Forecasted maximum system demand for month "t"
Time ("t")	=	Forecast time horizon
Delivered Demand Forecast ("$\widehat{Demand}_t$")	=	Forecast of delivered demand for month "t"
Temperature Deviation ("$\Delta Temperature_{Normal,Design,t}$")	=	Deviation of peak hour/day design temperature from monthly normal peak temperature
Conservation ("$Conservation_{Peak,t}$")	=	Ramped/shaped peak conservation resulting from programmatic conservation targets; IRP Optimal DSR

For the electric peak forecast, the normal design peak hour temperature is based on the median ("1 in 2" or 50th percentile) of the last of seasonal minimum temperatures for years 1988 to 2017 during peak hours (HE8 to HE20) observed at Sea-Tac (KSEA), as reported by NOAA. For winters spanning 1988 to 2017, the median observed peak temperature is 23 degrees Fahrenheit. The annual winter peak forecast is set at the maximum normal peak observed in a year, which is currently a December weekday evening.

For the natural gas peak day forecast, the design peak day is a 52 heating degree day (13 degrees Fahrenheit average temperature for the day). This standard was adopted in 2005 after a detailed cost-benefit analysis requested by the WUTC. The analysis considered both the value customers place on reliability of service and the incremental costs of the resources necessary to provide that reliability at various temperatures. We use projected delivered demand by class with this design temperature to estimate natural gas peak day demand. PSE's natural gas planning standard covers 98 percent of historical peak events, and it is unique to our customer base, our service territory and the chosen form of energy.

For the 2021 IRP Base Peak Demand Scenario, the effects of the 2020 and 2021 DSR targets are netted from the peak demand forecast to account for programmatic conservation already underway. This enables the choice of optimal resources and conservation to meet peak demand. Once the optimal DSR is derived from the IRP, the peak demand forecast is further adjusted for the peak contribution of future conservation.

2. STOCHASTIC DEMAND FORECASTS

Demand forecasts are inherently uncertain, and to acknowledge this uncertainty, the IRP considers stochastic forecast scenarios. Examples of drivers of forecast uncertainty include future temperatures, customer growth, usage levels and electric vehicle growth. To model these uncertainties, multiple types of stochastic forecast scenarios are created for different IRP Analyses. These demand and peak forecast permutations include:

- Monthly demand and peak forecasts
    - 250 gas and 310 electric stochastic monthly demand and peak forecasts
    - high/low forecast monthly demand and peak forecasts
- Hourly demand forecasts
    - A typical hourly load shape
    - 88 stochastic hourly forecasts for years 2027-2028 and 2031-2032.

Monthly Demand and Peak Demand

To create the set of stochastic electric and natural gas demand forecasts, the demand forecasts assume economic/demographic, temperature, electric vehicle and model uncertainties. The high and low demand forecasts are derived from the distribution of these stochastic forecasts at the monthly and annual levels.

Economic and Demographic Assumptions

The econometric demand forecast equations depend on certain types of economic and demographic variables; these may vary depending on whether the equation is for customer counts or use per customer, and whether the equation is for a residential or non-residential customer class. In PSE’s demand forecast models, the key service area economic and demographic inputs are population, employment, unemployment rate, personal income, manufacturing employment and US gross domestic product (GDP). These variables are inputs into one or more demand forecast equations.

To develop the stochastic simulations of demand, a stochastic simulation of PSE’s economic and demographic model was performed to produce the distribution of PSE’s economic and demographic forecast variables. Since these variables are a function of key U.S. macroeconomic variables such as population, employment, unemployment rate, personal income, personal consumption expenditure index and long-term mortgage rates, we utilized the stochastic simulation functions in EViews[1] by providing the standard errors for the quarterly growth of key U.S. macroeconomic inputs into PSE's economic and demographic models. These standard errors were based on historical actuals from the last 30 years, ending 2019. This created 1,000 stochastic simulation draws of PSE's economic and demographic models, which provided the basis for developing the distribution of the relevant economic and demographic inputs for the demand forecast models over the forecast period. Outliers were removed from the 1,000 economic and demographic draws. Then 250 draws were run through the electric and natural gas demand forecasts to create the 250 stochastic simulations of PSE's demand forecasts.

Temperature

Uncertainty in the levels of heating and cooling load is modeled by considering varying historical years' degree days and temperatures. Randomly assigned annual "normal" weather scenarios are sourced from actual observations of degree days for electric and natural gas demand and seasonal minimum/maximum on-peak hourly temperatures for electric peak. The years considered for stochastic energy demand and peak range between 1990 and 2019.

Electric Vehicles

PSE's high and low EV energy consumption scenarios are based on PSE's base case EV forecast. The high and low scenarios were developed by calibrating data from the Pacific Northwest National Laboratory's "Electric Vehicles at Scale – Phase I; Analysis: High EV Adoption Impacts on the Western U.S. Power Grid" (July 2020) to PSE's EV forecast. To determine EV energy consumption and peak loads, the ratios of kWh/vehicle and kW/vehicle for residential charging and commercial charging were calculated based on PSE's load forecast data in the year 2028. The ratios were applied to the high and low scenarios of incremental EVs in the PSE balancing area.

Model Uncertainty

The stochastic demand forecasts consider model uncertainty by adjusting customer growth and usage by normal random errors, consistent with the statistical properties of each class/sub-class regression model. Model adjustments such as these are consistent with Monte-Carlo methods of assessing uncertainty in regression models.

The high and low demand forecasts are defined in the IRP as the monthly 90th and 10th percentile, respectively, of the 250 stochastic simulations of demand based on uncertainties in the economic and demographic inputs and the weather inputs.

1 / EViews is a popular econometric forecasting and simulation tool.

Hourly Demand

Resource Adequacy Modelling

For the resource adequacy model, 88 stochastic hourly forecasts for year 2027-2028 and 2031-2032 were developed. For the period April 1, 2013 to December 31, 2019, PSE used the statistical hourly regression equation to estimate hourly demand relationships:

$$Demand_{h,d,s,t} = \boldsymbol{\zeta_h}\left[(1 - D_{h=1})Demand_{h-1,d,t} \quad \boldsymbol{D_{M,t}} \quad D_{Hol,d,t} \quad \boldsymbol{D}_{DoW,d,t} \quad \boldsymbol{T}_{h,d,t}\right] + u_{i,d,t}$$

where:

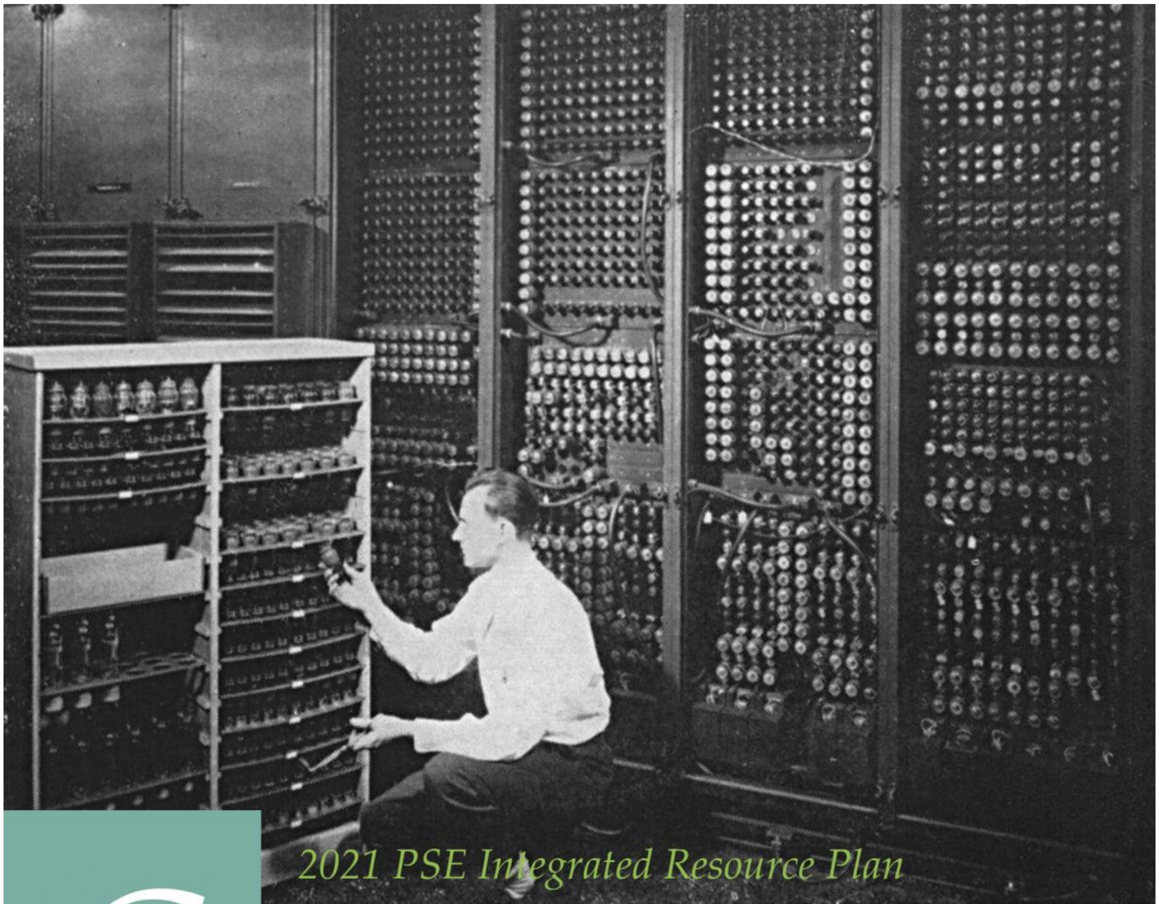
$$\boldsymbol{T}_{h,d,t} = \left[\max(55 - T_{h,d,t}, 0) \quad \max(T_{h,d,t} - 55,0) \quad \max(55 - T_{h,d,t}, 0)^2 \quad D_{h=1}\max(40 - DAvg_{t-1}, 0) \quad D_{h=1}\max(DAvg_{t-1} - 70,0)\right]$$

Hourly Demand ("$Demand_{h,d,t}$")	=	PSE hourly demand
Hour "h"	=	Hour of day {1…24}
Day "d"	=	Day grouping {Weekday, Weekend/Holiday}
Date "t"	=	Date
Daily temperature shape "s"	=	Indicator of daily average temperature type
Regression Coefficients ("$\boldsymbol{\zeta_h}$")	=	Vector regression coefficients
Hourly Temperature ("$T_{h,d,t}$")	=	Hourly temperature at Sea-Tac ("KSEA")
Lag Daily Average Temp ("$DAvg_{t-1}$")	=	Previous daily average temperature
Monthly Indicator ("$\boldsymbol{D}_{M,t}$")	=	Vector of monthly date indicator variables
Day of Week Indicator ("$\boldsymbol{D}_{DoW,d,t}$")	=	Vector day indicators {Monday, Friday, Sunday}
Holiday Indicator ("$D_{Hol,d,t}$")	=	Holiday indicator
Hour Ending 1 Indicator ("$D_{h=1}$")	=	Indicator Variable for hour ending 1
Error term (or "$u_{i,d,t}$")	=	ARMA(1,1) error term

Demand is estimated for each hour, day of week type and daily average temperature type, yielding 24x2x4 sets of regression coefficients. An annual hourly demand profile is forecasted by fitting an annual 8,760-hour temperature profile and calendar. After creating this fitted value, the forecast is further calibrated by additional hourly demand from an annual EV profile, an AC saturation adjustment for future peak hours with temperatures greater than 72 degrees, the monthly delivered demand ("$\widehat{Demand}_{N,t}$") forecasted for the 2021 Base Demand Forecast, and various stochastic temperature and demand scenarios.

AURORA Modeling Process

An hourly profile of PSE electric demand was produced to support the IRP portfolio analyses. We use our hourly (8,760 hours + 10 days) profile of electric demand for the IRP as an input into the AURORA portfolio analysis. One full year of hourly data is created and then the monthly demand forecast is shaped to the hourly data when running the portfolio analysis. Day one of the hourly shape is a Monday, day two is a Tuesday and so on, so the AURORA model adjusts the first day to line up January 1 with the correct day of the week. The estimated hourly distribution is built using statistical models relating actual observed temperatures, recent demand data and the latest customer counts.



G Electric Analysis Models

This appendix describes the analytical models used in the electric analysis for the 2021 IRP.

Contents

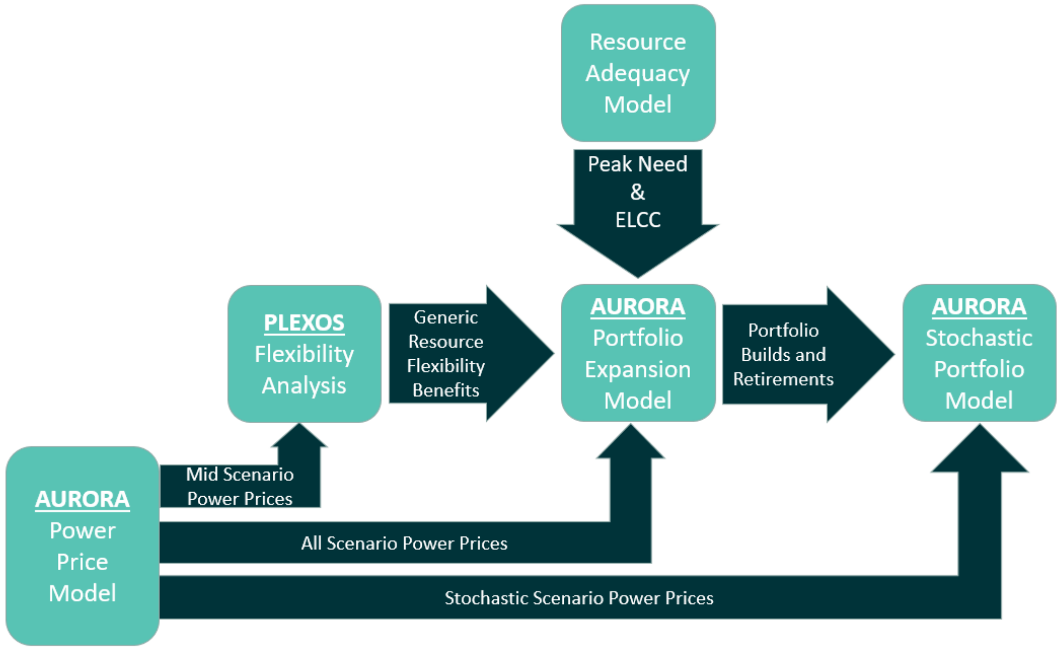
1. ELECTRIC MODELING PROCESS

PSE uses three models for electric integrated resource planning: AURORA, PLEXOS and the Resource Adequacy Model (RAM). AURORA is used in several ways: 1) to analyze the western power market to produce hourly electricity price forecasts of potential future market conditions and resource dispatch, 2) to create optimal portfolios and test these portfolios to evaluate PSE's long-term revenue requirements for the incremental portfolio and the risk of each portfolio, and 3) in the stochastic analysis, the model is used to create simulations and distributions for various variables. PLEXOS estimates the cost savings due to sub-hour operation for new generic resources. PSE's probabilistic Resource Adequacy Model enables PSE to assess the following; 1) to quantify physical supply risks as PSE's portfolio of loads and resources evolves over time, 2) to establish peak load planning standards, which in turn leads to the determination of PSE's capacity planning margin, and 3) to quantify the peak capacity contribution of a renewable and energy-limited resource (its effective load carrying capacity, or ELCC). The peak planning margin and ELCCs are inputs into PSE's portfolio expansion model. A full description of RAM is in Chapter 7.

Figure G-1 demonstrates how the models are connected. The following steps are used to get to the least-cost portfolio for each of the scenarios and sensitivities.

1. Create Mid-C power prices in AURORA for each of the five electric price scenarios.
2. Using the Mid Scenario Mid-C prices from AURORA, run the flexibility analysis in PLEXOS to find the flexibility benefit for each of the generic supply-side resources.
3. Run RAM to find the peak capacity need and ELCCs.
4. Using the electric price forecast, peak capacity need, ELCC and flexibility benefit, run the portfolio optimization model for new portfolio builds and retirements for each of the 37 different scenario and sensitivity portfolios.
5. Develop stochastic variables around power prices, gas prices, hydro generation, wind generation, PSE loads and thermal plant forced outages.

Figure G-1: Electric Analysis Methodology



AURORA Electric Price Model

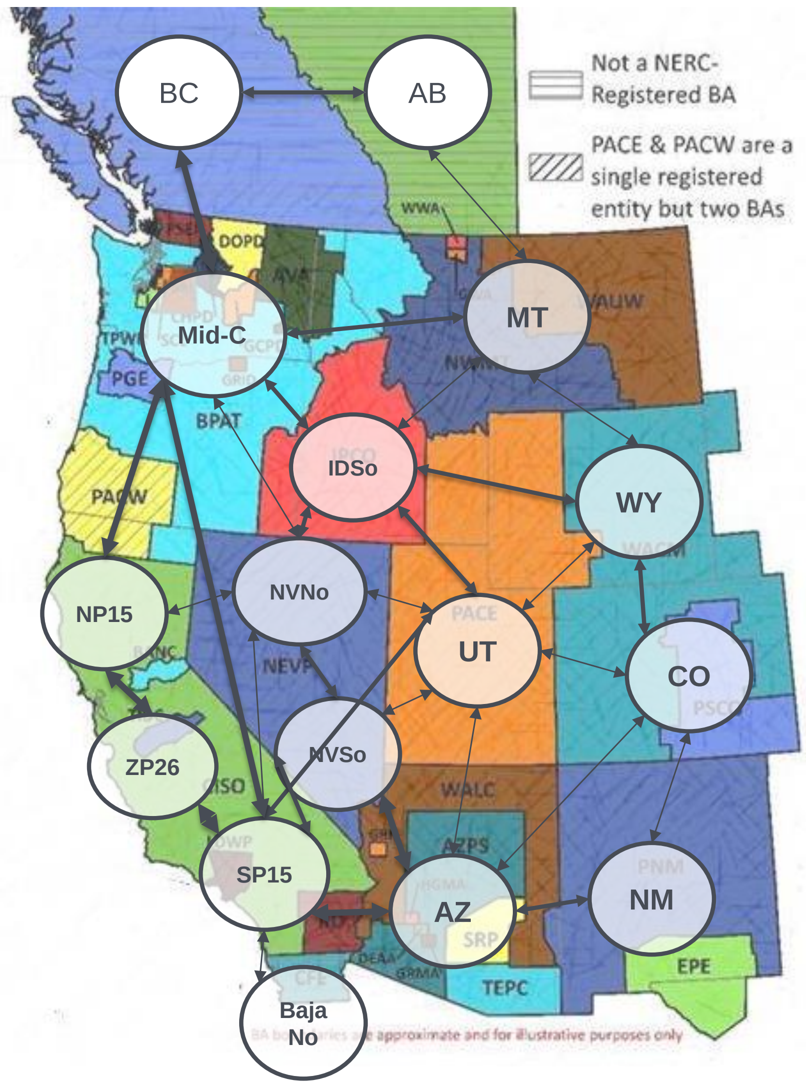
A power price forecast is developed for each of the scenarios modeled in an IRP. In this context, "power price" does not mean the rate charged to customers, it means the price to PSE of purchasing (or selling) 1 megawatt (MW) of power on the wholesale market given the economic conditions that prevail in that scenario. This is an important input to the analysis, since market purchases make up a substantial portion of PSE's resource portfolio.

Creating wholesale power price assumptions requires performing two WECC-wide AURORA model runs for each scenario. (AURORA is the hourly chronological price forecasting model based on market fundamentals used widely throughout the IRP process.)

- The first AURORA run identifies the capacity expansion needed to meet regional loads. AURORA looks at loads and peak demand plus a planning margin, and then identifies the most economic resource(s) to add to make sure that all of the regions modeled are in balance.

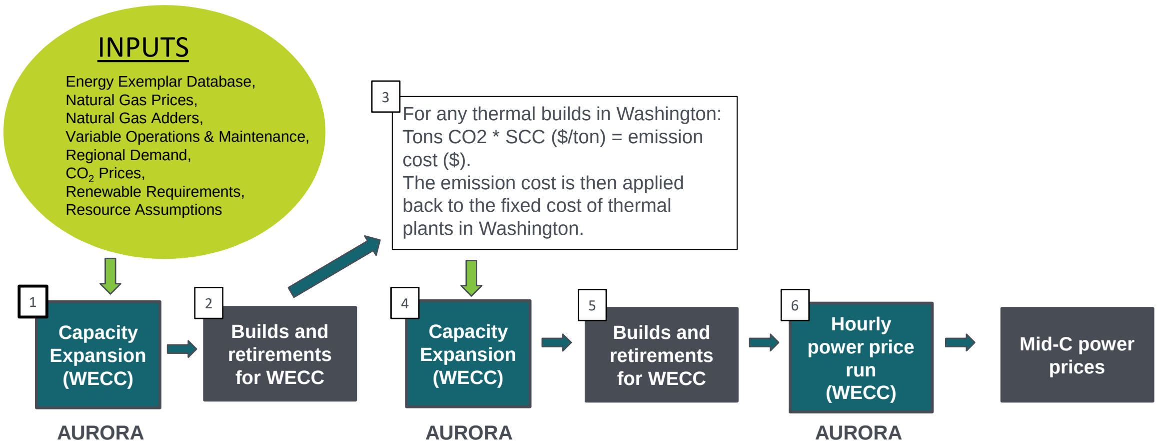
- The second AURORA run produces hourly power prices. A full simulation across the entire WECC region produces power prices for all of the 16 zones shown in Figure G-2. The lines and arrows in the diagram indicate transmission links between zones. The heavier lines represent greater capacity to flow power from one zone to another.

Figure G-2: AURORA System Diagram



The Pacific Northwest Zone, labeled Mid-C in the diagram above, is modeled as the Mid-Columbia (Mid-C) wholesale market price. The Mid-C market includes Washington, Oregon, Northern Idaho and Western Montana. Figure G-3 illustrates PSE’s process for creating wholesale market power prices.

Figure G-3: PSE IRP Modeling Process for AURORA Wholesale Power Prices



PSE's electric price model follows a six-step process to forecast wholesale electric prices.

1. Long run capacity expansion for the Western Electricity Coordinating Council (WECC). The database includes only existing and planned resources for the next few years, but with load growth, there are not enough resources to meet needs for the next 20 years. So, PSE runs a capacity expansion to add new generic resources to make sure the WECC stays in load resource balance.
2. The long run capacity expansion produces a set of builds and retirements for the WECC.
3. PSE pulls the builds for Washington state and looks for any new natural gas plants added to Washington state. PSE then calculates the social cost of greenhouse gas (SCGHG) adder for any natural gas plants added in Washington.
4. The capacity expansion model is then re-run with the SCGHG adder.
5. The updated model then produces a set of builds and retirements for the WECC that include the SCGHG adder for Washington state.
6. This final set of builds and retirements is then run through the standard zonal model in AURORA for every hour of the 20 years for a complete dispatch.
7. This standard zonal hourly dispatch then produces an electric price forecast for each zone identified in Figure G-2 above. PSE uses the price forecast for the Mid-C zone as the wholesale market price in the portfolio model.

Electric Price Model Inputs

Electric price model inputs are summarized in Chapter 5; additional detail is provided below as appropriate.

ENERGY EXEMPLAR DATABASE. PSE used Energy Exemplar's AURORA database titled "US_CANADA_DB_2018_V1" released in January 2018. The databased included extensive updates to demand, fuels, resources, transmission links and monthly hydro availability since the last database release.

- Historical hourly demand was derived directly from WECC Transmission Expansion Planning Policy Committee Load Zones for all years through 2016. 10-year forecasts were derived from reported Planning Areas in the 2016 FERC-714.
- Transmission links were updated based on the WECC 2016 Power Supply Assessment.
- Resources were updated to reflect the 2016 EIA-860, with supplemental information from the August 2017 EIA-860M and the 2016 EIA-923 datasets.
- Historical Hydro 80 Water years were updated to reflect assumptions available from the Bonneville Power Administration (BPA, as delivered by the Northwest Power and Conservation Council). At the time of the release, the report reflected hydro output to be used for the Pacific Northwest Power Supply Adequacy Assessment for 2023.

NATURAL GAS PRICES. For natural gas prices, PSE uses a combination of forward market prices and fundamental forecasts acquired in Spring 2020 from Wood Mackenzie. The natural gas price forecast is an input into the AURORA Electric Price Modeling and AURORA Portfolio Model. The natural gas price inputs are described in Chapter 5.

NATURAL GAS ADDERS AND VARIABLE OPERATIONS & MAINTENANCE (VOM). The Energy Exemplar database uses Henry Hub gas prices as the base fuel price. So, in the database, the fuel price adders are used as the basis differential between Henry Hub and the other fuel hubs. Since PSE inputs the different hub prices, the adders are updated to be pipeline tariff rates to get the burner tip price.

Figure G-4: Fuel Adders for Sumas and Stanfield

Fuel Hub	Adder	Default Fuel Adder	Revised Fuel Adder
Sumas	NGNW-Coastal	-0.20	0.06
Sumas	NG1NW-Coastal	0.32	0.13
Sumas	NG2NW-Coastal	0.29	0.21
Sumas	NG3NW-Coastal	0.63	0.28
Stanfield	NGNW-Inland	-0.20	0.06
Stanfield	NG1NW-Inland	0.32	0.07
Stanfield	NG2NW-Inland	0.29	0.13
Stanfield	NG3NW-Inland	0.63	0.20

REGIONAL DEMAND. This IRP uses the regional demand developed by the NPCC[1] 2019 Policy Update to the 2018 Wholesale Electricity Forecast, the most recent forecast available at the time of this analysis. Updated 2020 loads and COVID-19 impacts were not available from the NPCC until February 2021. Regional demand is used only in the WECC-wide portion of the AURORA analysis that develops wholesale power prices for the scenarios.

RENEWABLE REQUIREMENTS. Renewable portfolio standards (RPS) and clean energy standards currently exist in 29 states and in the District of Columbia, including most of the states in the WECC and British Columbia. Each state and territory defines renewable energy sources differently, sets different timetables for implementation, and establishes different requirements for the percentage of load that must be supplied by renewable resources. PSE incorporated renewable portfolio and clean energy standards passed in and before the year 2020. All of these renewable requirements are detailed in Chapter 5.

CO_2 PRICES. The social cost of greenhouse gases (SCGHG) cited in the Washington Clean Energy Transformation Act (CETA) as a cost adder to thermal resources in Washington state is included in the electric price modeling. Detailed inputs are provided in Chapter 5 and the Excel file with the numbers used is included as part of Appendix H.

1 / The NPCC has developed some of the most comprehensive views of the region's energy conditions and challenges. Authorized by the Northwest Power Act, the Council works with regional partners and the public to evaluate energy resources and their costs, electricity demand and new technologies to determine a resource strategy for the region.

RESOURCE ASSUMPTIONS. As a part of the electric price modeling process, PSE uses the standard database for the WECC region provided by Energy Exemplar with the AURORA modeling software. This database includes information on the retirement dates of existing resources in the WECC system, as well as build and retirement dates for planned resources that are not currently in operation.

Long-run Optimization

AURORA also has the capability to simulate the addition of new generation resources and the economic retirement of existing units through its long-term optimization studies. This optimization process simulates what happens in a competitive marketplace and produces a set of future resources that have the most value in the marketplace. New units are chosen from a set of available supply alternatives with technology and cost characteristics that can be specified through time. New resources are built only when the combination of hourly prices and frequency of operation for a resource generate enough revenue to make construction profitable, unless reserve margin targets are selected. (That is, when investors can recover fixed and variable costs with an acceptable return on investment.) AURORA uses an iterative technique in these long-term planning studies to solve the interdependencies between prices and changes in resource schedules.

WECC Coal Plant Retirements

PSE added constraints on coal technologies to the AURORA model in order to reflect current political and regulatory trends. Specifically, no new coal builds were allowed in any state in the WECC. Planned retirements are shown in Figure G-5 below.

Figure G-5: Planned Coal Retirements across the WECC

Plant Name	State	Nameplate MW	Retirement Year
Colstrip 3	MT	740	2025
Colstrip 4	MT	740	2025
North Valmy 2	NV	268	2025
Centralia 2	WA	670	2025
Jim Bridger 1	WY	531	2028

WECC Renewable Builds

PSE added 3,123 MW of renewable resources to Energy Exemplar's US_CANADA_DB_2018_V1 database based on the data from the S&P Global Data[2] as of February 2020. Figure G-6 provides new build capacity for solar and wind resources from 2016 to 2024. The majority of the new renewable resources are located in the California region.

Figure G-6: Planned New Builds in the WECC (USA)

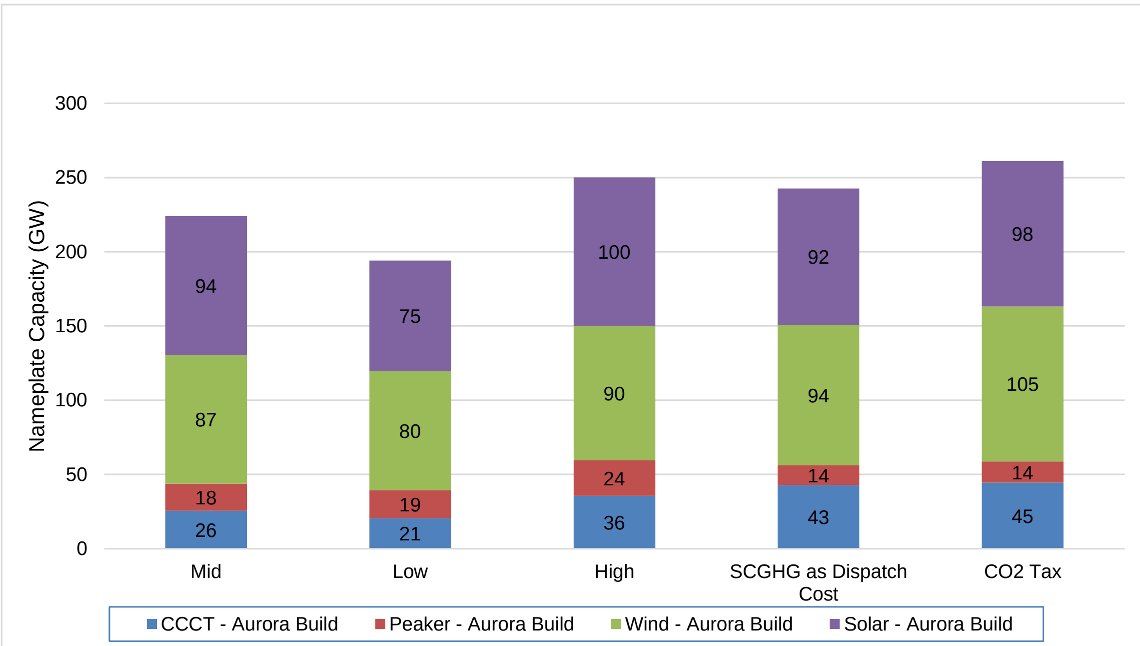
Planned Renewable Build	MW
Solar	1,607
Wind	1,516
Total Planned Build	**3,123**

2 / S&P Global formerly known as SNL, which stands for Savings and Loan, is a company that collects and disseminates corporate, financial and market data on several industries including the energy sector (www.spglobal.com).

AURORA Builds

AURORA is able to run a long-term optimization model to choose a set of available supply to meet both energy needs and peak needs. New resources are built only when the combination of hourly prices and frequency of operation for a resource generate enough revenue to make construction profitable. Figure G-7 shows AURORA builds in the five scenarios for both the U.S. and Canada WECC.

Figure G-7: WECC Aurora Builds by 2045



Power Price Forecast Results

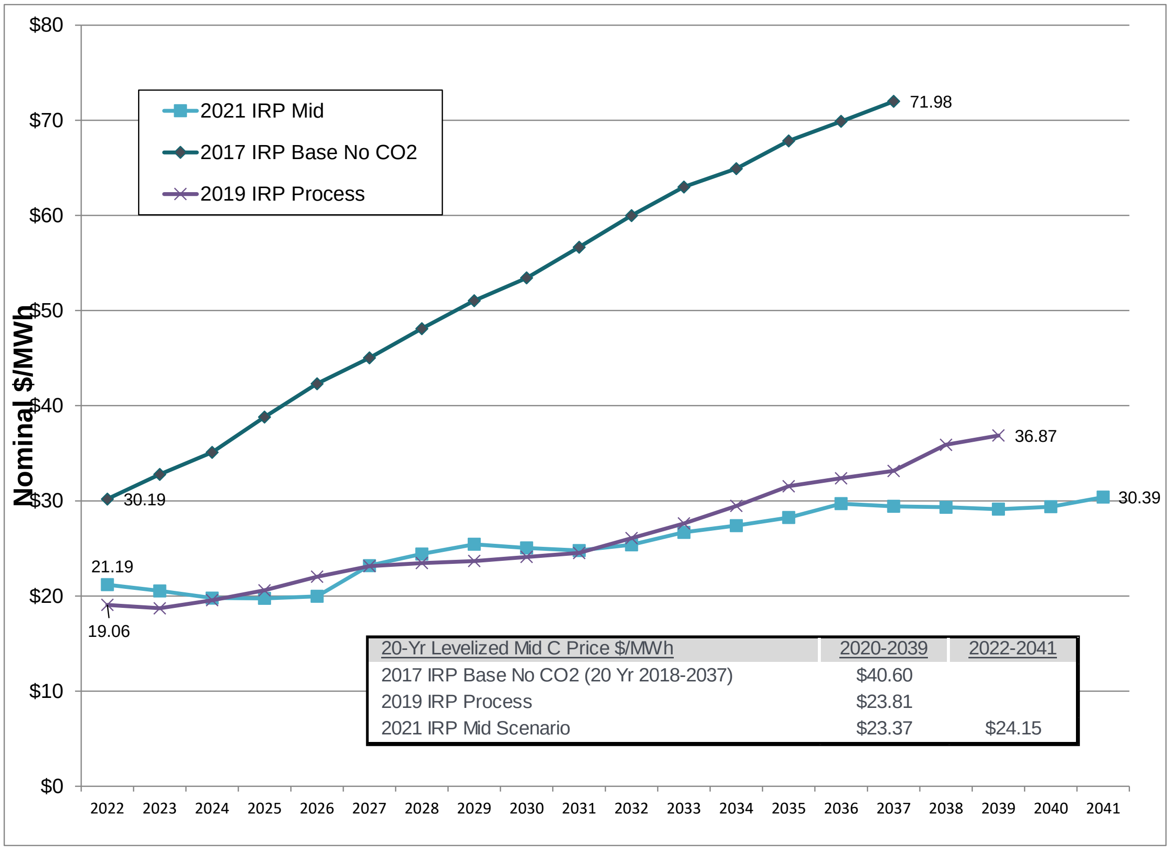
The table below increments through the updates to power prices from the 2019 IRP progress report power prices to the final power prices filed in the 2021 IRP. The 2019 IRP time frame was 2020 – 2039 and the 2021 IRP time frame is 2022 – 2041.

Figure G-8: Changes in Power Prices from 2019 IRP Progress Report to 2021 IRP

	Nominal ($/MWh)	20-yr Levelized	Incremental Difference	Cumulative Difference from 2019 IRP Progress Report
2017 IRP Base + No CO2		$40.60		
0	2019 IRP Progress Report Mid Scenario	$23.81	($16.79)	
1	Modeling updates for the Draft Power Prices • Updated Aurora from version 13.3 to version 13.4 • Updated New Builds and Retirements using SNL Data • Gas Price Update using Fall 2019 Wood Mackenzie Forecast	$24.47	$0.66	$0.66
2	Modeling updates for the Final Power Prices • Update Regional Demand using the Northwest Power and Conservation Council (NPCC) 2019 Policy Update to the 2018 Wholesale Electricity Forecast • Gas Prices from Spring 2020 Long Term View Price Update from Wood Mackenzie • Update estimated state sales forecast for Clean Energy Targets - Final Mid Scenario	$24.15	($0.32)	$0.34

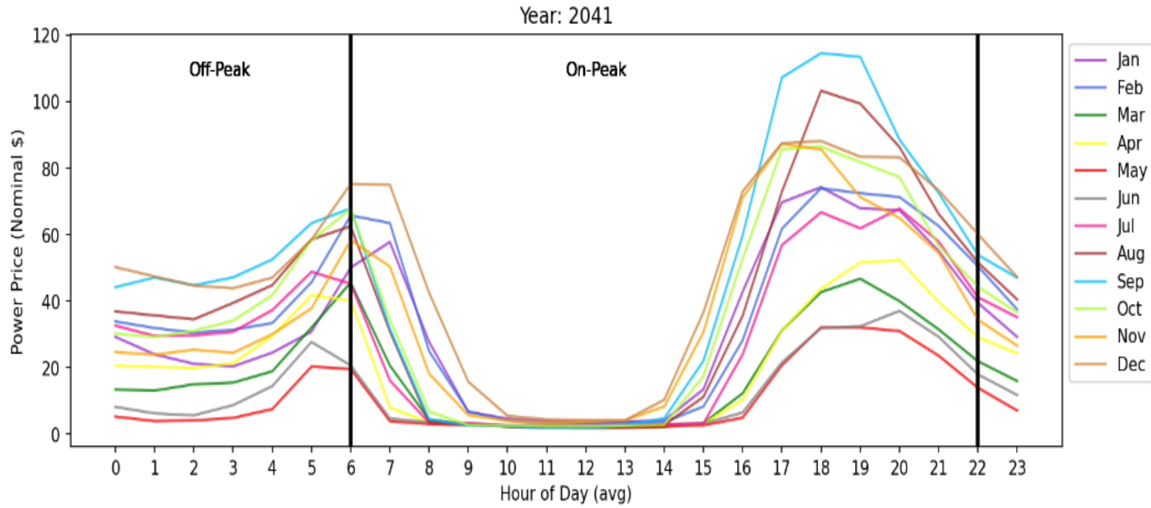
Figure G-9 below is a comparison of the annual average Mid-C power price from the 2017 IRP and 2019 IRP Progress Report to the 2021 IRP. The increase in renewable resources in the region is causing the decrease in power prices. The power prices are based on the cost of the marginal resource in each hour. Given the large amount of renewable resources, they are pushing out the dispatch curve, and the renewable resources are now the marginal unit in many hours. The dispatch cost of a renewable resource is $0, so the price for that hour is now $0. With many hours at around $0, the average cost of power is significantly lower than the 2017 IRP

Figure G-9: Comparison of Mid-C Annual Average Power Price



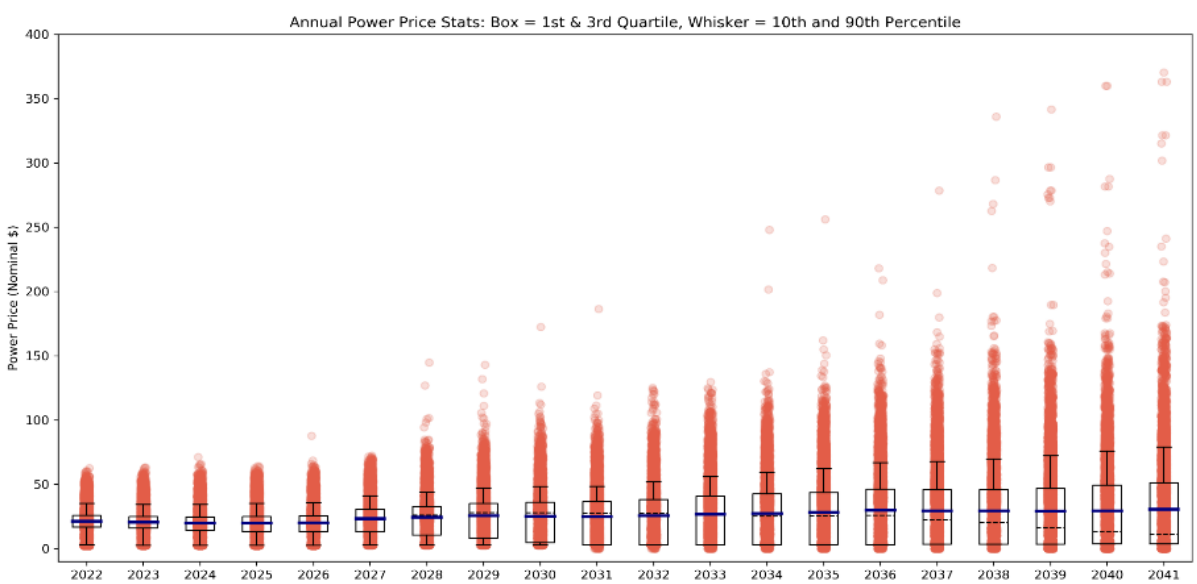
However, the increased supply of intermittent resources causes significant price volatility. As the renewable resources fall off in the evening, costly peaking resources pick up the supply, which results in larger swings in power prices from on-peak to off-peak. Figure G-10 below is the average hourly power price for each month in 2041. This growing difference in hourly prices between mid-day and morning/evening peak increases with more renewables

Figure G-10: 2041 Hourly Mid-C Price Shape by Month



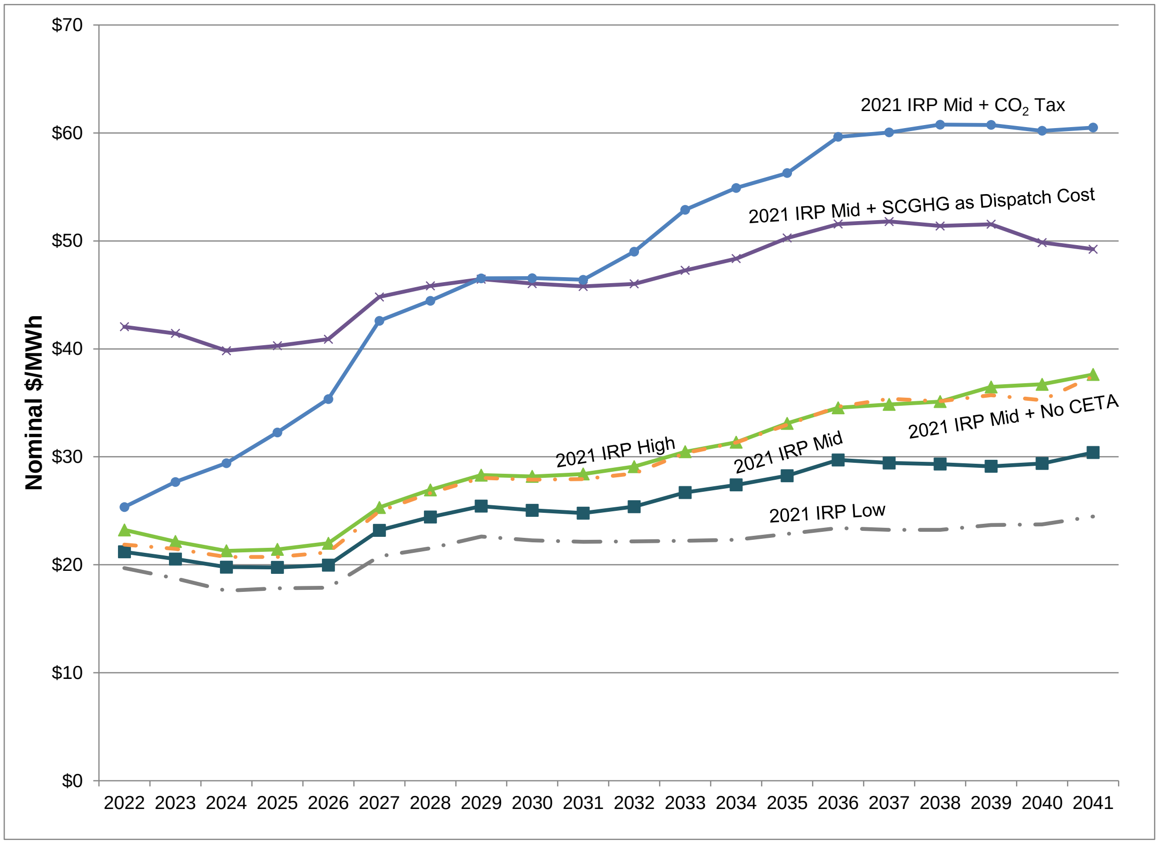
Mid-C price forecasts are highly variable even under normal hydro conditions and assuming a fully optimized wholesale market. Figure G-11 shows the hourly Mid-C Price from 2022 through 2041. In the late years, the hourly prices become more volatile and there is a growing number of high-price hours as more renewables are added to the system. A divergence of the median and mean power price is seen in the late years, indicating a lot of low power prices, but a few very expensive prices pulling up the mean.

Figure G-11: Hourly Mid-C Price from 2022 through 2041



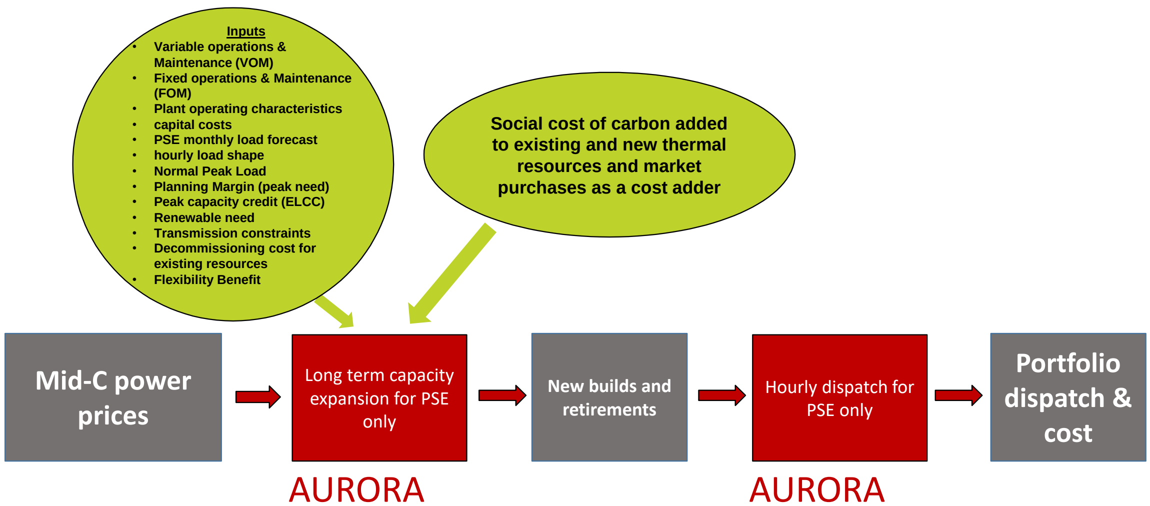
PSE created low, mid and high scenarios for the electric analysis to test how different combinations of two fundamental economic conditions – customer demand and natural gas prices – impact the least-cost mix of resources. Along with testing changes to economics impacts, PSE also ran two scenarios with different CO_2 prices. Figure G-12 below show the annual average Mid-C price forecast for the low, mid, high, and two CO_2 price scenarios.

Figure G-12: Annual Average Mid-C Power Price Forecast



AURORA Portfolio Model

Figure G-13: Aurora Portfolio Model



PSE's electric portfolio model follows a seven-step process to forecast wholesale electric prices.

1. A Long Term Capacity Expansion (LTCE) model is used to forecast the installation and retirement of resources over a long-term planning horizon not only to keep pace with energy and peak need but also to meet the renewable requirement to be CETA and RPS compliant.
2. The LTCE run produces a set of builds and retirements for PSE.
3. PSE then calculates the social cost of greenhouse gas (SCGHG) adder for any existing and new natural gas plants.
4. The capacity expansion model is re-run with the SCGHG adder.
5. The updated model then produces a set of builds and retirements for PSE that include the SCGHG as a planning adder.
6. This final set of builds and retirements is then run through the standard zonal model in AURORA for every hour of the 24-years for a complete dispatch.
7. This standard zonal hourly dispatch then produces the portfolio dispatch and cost.

Long-Term Capacity Expansion Model

A Long-Term Capacity Expansion simulation (LTCE) is used to forecast the installation and retirement of resources over a long period of time. Over the study period of an LTCE simulation, existing resources may be retired and new resources are added to the resource portfolio.

To perform the LTCE modeling process, PSE uses a program called AURORA provided by Energy Exemplar. AURORA is an algebraic solver software used to complete analyses and forecasts of the power system that has been used for decades within the utility industry. The software provides a variety of functions that allow PSE to perform analyses quickly and efficiently, while maintaining a rigorous record of the data used to perform simulations.

The LTCE model begins the resource planning process by taking into account the current fleet of resources available to PSE, the options available to fill resource needs, and the necessary planning margins required for fulfilling resource adequacy needs. The resource need is calculated dynamically as the simulation is performed using demand forecasts. The LTCE model has the discretion to optimize the additions and retirements of new resources based on resource need, economic conditions, resource lifetime and competitive procurement of new resources. The new resources that are available to the model to acquire are established prior to the execution of the model. PSE worked with IRP stakeholders to identify potential new resources, and compiled the relevant information to these resources, such as capital costs, variable costs, transmission needs and output performance. Contracts are not included in this portion of the modeling process, as non-economic contracts are a separate portion of the resource marketplace that cannot be captured in the model.

Optimization Modeling

Optimization modeling is the process of finding the optimal minimum or maximum value of a specific relationship, called the objective function. The objective function in PSE's LTCE model seeks to minimize the revenue requirement of the total portfolio, or, in other words, the cost to operate the fleet of generating resources. An example of a revenue requirement function is outlined below:

The revenue requirement at any given time is defined as:

$$RR_t = \sum_{Resource} (Capital\ Costs_{Resource} + Fixed\ Costs_{Resource} + Variable\ Costs_{Resource}) + Contract\ Costs + DSR\ Costs + Market\ Purchases - Market\ Sales$$

Where t is the point in time, and RR_t is the revenue requirement at that time.

Over the entire study period, the model seeks to minimize the *Present Value* of the total revenue requirement, defined as:

$$PVRR = \sum_{t=1}^{T} RR_t * [\frac{1}{(1+r)^t} + \frac{1}{(1+r)^{20}}] * \sum Resource\ End\ Effects$$

Where PVRR is the present value of the Revenue Requirement over all time steps, and r is the inflation rate used.

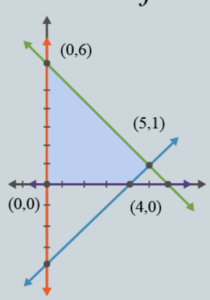
In order to achieve the optimization, various methods may be used including linear programming, integer programming and mixed-integer programming (MIP). AURORA utilizes MIP which is a combination of integer programming and linear programming.

LINEAR PROGRAMMING. Linear programming, also known as linear optimization, is a mathematical model that is represented by linear relationships and constraints. Linear programming is best used to optimize a value that is constrained by a system of linear inequalities. In a power system model, these constraints arise from the capacities, costs, locations, transmission limits and other attributes of resources. The constraints combine to form the boundaries of the solutions to the objective function.

A basic example of linear programming, where an objective function C(x,y) is being minimized and maximized:

$$\textit{constraints:}\ \begin{cases} x + y \geq 6 \\ x - y \geq 4 \\ x \geq 0 \\ y \geq 0 \end{cases}$$

$$\textit{Objective Function:}\ C = 2x + y$$



(0,0): $C = 2(0) + (0) = 0$ minimum

(0,6): $C = 2(0) + (6) = 6$

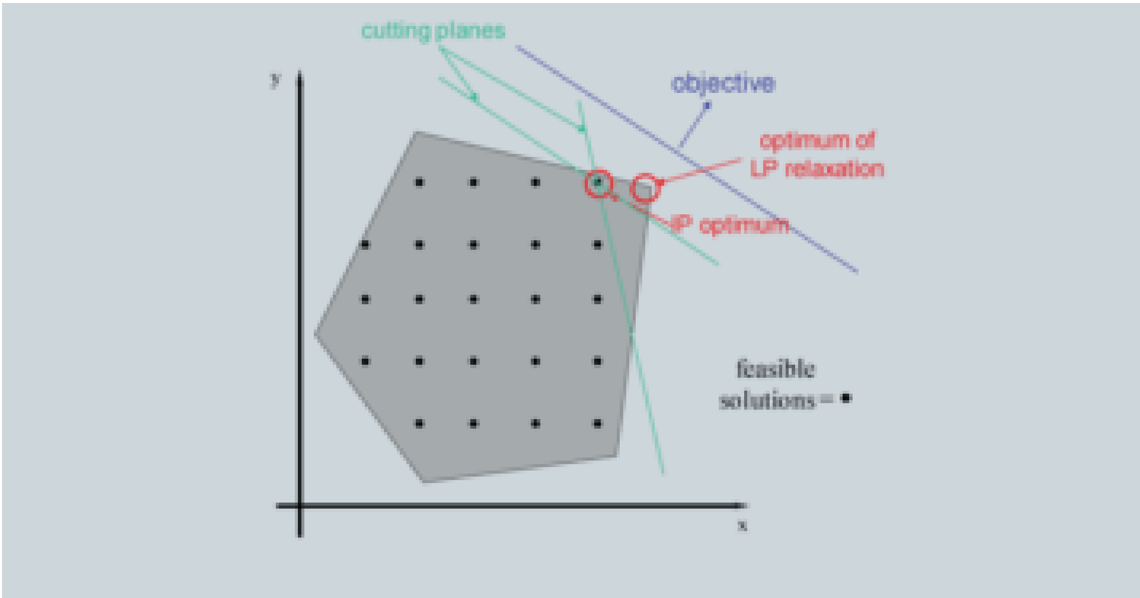
(5,1): $C = 2(5) + (1) = 11$ maximum

(4,0): $C = 2(4) + (0) = 8$

Calcworkshop.com

INTEGER PROGRAMMING. Integer Programming is another mathematical optimization method in which some or all of the variables are restricted to integer values. The optimal solution may not be an integer value, but the limitation of the values in the model forces the optimization to produce a solution that accounts for these integer values. In the context of a utility, this may come in the form of having a discrete number of turbines that can be built, even though having a non-integer number of turbines will produce the optimal capacity.

A visual example of an integer programming problem. The optimal solution lies in the grey area, but only solutions that are represented by the black dots are valid:



MIXED INTEGER PROGRAMMING. Mixed integer programming (MIP) refers to a combination of Linear and Integer programming, where a subset of the variables and restrictions take on an integer value. MIP methods are the best suited for handling power system and utility models, as the decisions and restraints faced by utilities are both discrete (how many resources to build, resource lifetimes, how those resources connect to one another) and non-discrete (the costs of resources, renewable profiles, emissions limitations). In AURORA, MIP methods are the primary solver for completing all simulations, including the LTCE models. These methods are performed iteratively and include vast amounts of data, which makes the settings used to run the model important in determining the runtime and precision of the solutions.

ITERATIVE SOLVING. When broken down into sets of equations and solving methodologies, the goal of optimization modeling can be deceptively simple. Limitations on computing power, the complexity of the model parameters, and vast amounts of data make a "true solution" impossible to solve for in many cases. In order to work around this, the LTCE model performs multiple iterations in order to converge on a satisfactory answer.

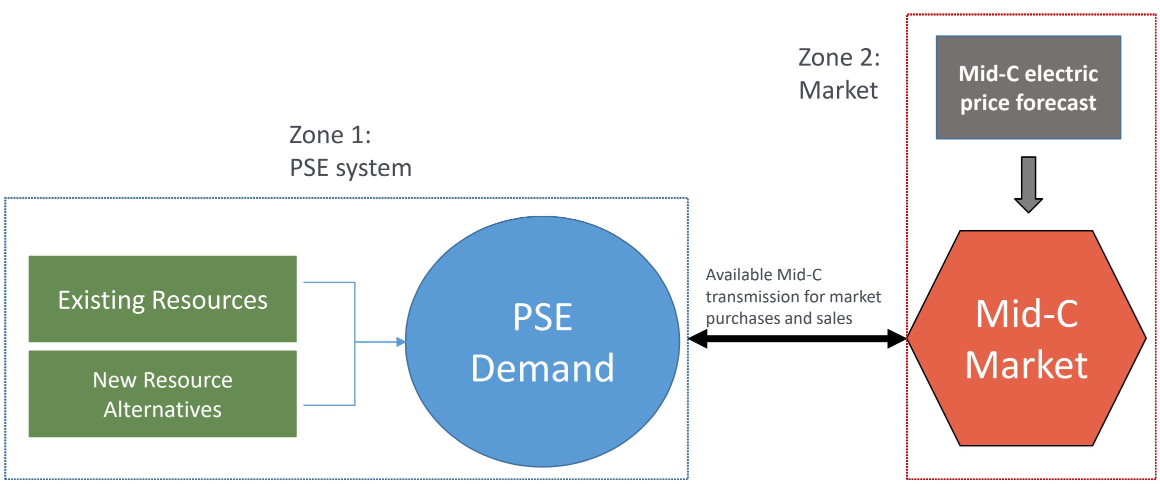
Given the complexity of the model being processed, the model does not produce the same results after each run. Over the course of multiple iterations, AURORA will compare the final portfolios and outputs of each iteration with the previous attempt. If the most recent iteration reaches a certain threshold of similarity to the previous (as determined by the model settings), and has reached the minimum number of iterations, the solution will be considered "converged" and provide it as the final output. If the model has reached the maximum number of iterations (also entered in the model settings), the final iteration will be considered the final output.

System Constraints

The solutions provided by the optimization of the LTCE model seek to provide a path to meeting PSE's load while minimizing the total price of the fleet. Without any constraints, the LTCE optimization model would select the resource that produces the greatest amount of power per dollar spent on the resource and build as many as were needed. This solution is trivial and does not provide any usable insight into how the utility should manage real resources. The addition of constraints allows the model to find a useful solution.

ZONAL CONSTRAINTS. The models use a "zonal model" of transmission, where the model is divided into "zones". The only transmission limits in the standard model are between zones, and PSE does not add more transmission constraints for most simulations due to limitations on runtime and computing power. The zonal model works best for generation optimization. A separate model called the "nodal model" can be used for transmission optimization. Given the current constraints on technology and computing power, there is no integrated model for generation and transmission. Figure G-14, 2 ZONE System, shows how this two-zone system operates in AURORA.

Figure G-14: 2 ZONE System: A graphical example of how PSE's 2-zone system is represented in AURORA, with the zones represented as rectangular boxes and the arrows between them representing transmission links.



For most simulations, PSE operates a two-zone system. This system serves to limit the amounts of market purchases that can be made at any given time as a result of transmission access to the Mid-Columbia market hub.

RESOURCE CONSTRAINTS. Resources in the model are defined by their constraints. A resource needs to be defined by constraints in order to make its behavior in the model match real-world operating conditions.

- **Resource Costs** – Generic resource costs give the model information about the capital costs in addition to variable and fixed operation and maintenance costs to make purchasing decisions.
- **Operating Characteristics** – Generic resource inputs contain information about when the resources can operate, including fuel costs, maintenance schedules and renewable output profiles. These costs include transmission installations.
- **Availability** – Resources have a finite lifetime, as well as a “first available” and “last available” year to be installed as a resource. Resources also have scheduled and random maintenance or outage events that are included in the model.

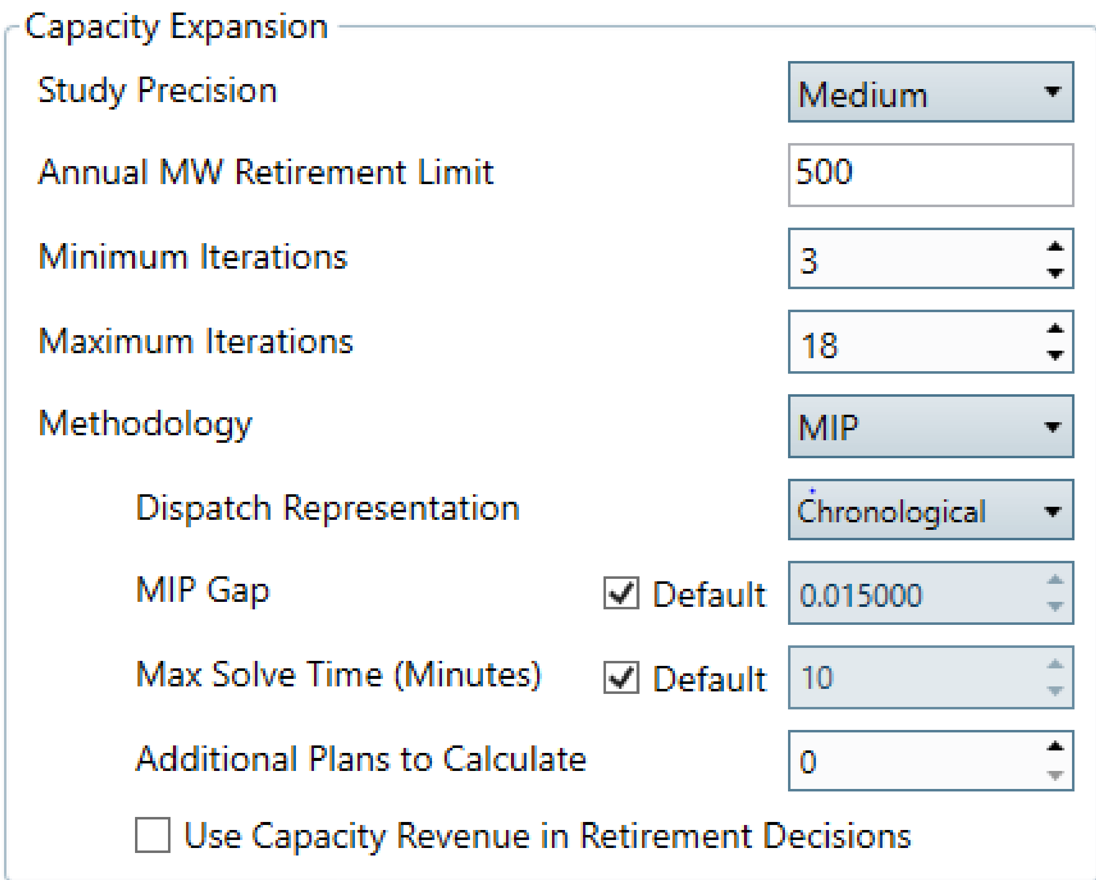
RENEWABLE CONSTRAINTS. The model must meet all legal requirements. The most relevant renewable constraints faced by PSE are related to the Renewable Portfolio Standard (RPS) and the Clean Energy Transformation Act (CETA). The renewable constraints are described in detail in Chapter 5.

Modeling Settings

The explanations provided for the PSE LTCE models rely heavily on the AURORA documentation provided by Energy Exemplar, and relevant excerpts are included below.

Prior to each individual LTCE model, parameters are set to determine how that simulation will be performed. The default parameters used by PSE are as follows:

Figure G-15: Standard Aurora Parameters for PSE's LTCE Model
These options are found in the project file under Simulation Options → Long Term Capacity Expansion → Study Options → Long Term



STUDY PRECISION. During the iterative optimization process, the study precision determines at what point the model determines that a solution has been successfully converged upon. Instead of reaching one "correct answer," the optimization process consists of multiple simulations that gradually converge on an optimized, stable answer given the data that it has. A visual representation of this process shows a model range gradually approaching an optimized solution. In setting a percentage value for the study precision, users determine what is considered "close enough" to the absolute ideal answer. Limitations on runtime and computing power are the main drivers of limiting the precision of a study.

The options for this setting include:

- High: Stops when the changes are less than 0.15 %,
- Medium: Stops when the changes are less than 0.55 %.
- Low: Stops when the changes are less than 2.5 %.

Through experimenting with these settings, PSE has determined that the optimal setting is Medium when considering trade-offs between runtime and precision.
ANNUAL MW RETIREMENT LIMIT. This setting limits the amount of generating capacity that can be economically retired in any given year. This setting does not include predetermined retirement dates, such as coal plant retirements, captured in the resources input data. PSE stayed with the default setting of 500 MW as a reasonable maximum for economic resource retirements to prevent any outlier years where vast amounts of resources are being retired.

MINIMUM ITERATIONS*.* This setting specifies the minimum number of iterations that the simulation must complete. PSE sets the minimum to three iterations to ensure that model decisions are being checked.

MAXIMUM ITERATIONS*.* This setting specifies the maximum number of iterations that the simulation must complete. PSE sets the maximum to 18 iterations to ensure that the runtime of the model does not become excessive. A simulation that is taking more than 15 iterations to solve will likely not converge into a usable solution.

METHODOLOGY. AURORA provides two options for this setting: Traditional and MIP. Traditional methodology uses the following steps to perform the simulation, described in the AURORA documentation:

> "Aurora uses the following steps in the Traditional Long-Term Optimization (Capacity Expansion) process:
>
> 1. The first iteration begins with resources selected to meet the planning reserve margins for the zones and pools being run. If reserve margin targets are not being used, the model will assume a reserve margin of the minimum of 0% as the beginning first year reserve margin for each pool and zone. The model will make the first iteration build decisions based on the new resource fixed costs.
> 2. Aurora enumerates all new resources.
> 3. The value for each existing resource is determined.
> 4. The value for each new enumerated resource is determined.
> 5. Resources are sorted by value."

This methodology is a faster method for handling relatively simple simulations, but results in longer runtimes for more complicated portfolios.

The MIP methodology uses a Mixed Integer Program to evaluate resource build and retirement decisions. The MIP allows for a different representation of resources within the model that leads to faster convergence times, more optimal (lower) system costs, and better handling of complex resource constraints. PSE employs the MIP methodology to take advantage of these benefits over traditional logic.

MIP-SPECIFIC SETTINGS. Some settings within the MIP selection refine the performance of the MIP methods. PSE often uses these settings at their default values, which are calculated based on the amount of data that has been read into the AURORA input database for the simulation. The options are described in the AURORA documentation and are explained in Figure G-16:

Figure G-16: The MIP-Specific Settings Used in the AURORA LTCE Model

Setting	Value Type	Definition
Dispatch Representation	Chronological	This methodology uses the dispatch of units in the chronological simulation (both costs and revenues) as the basis for the valuation of the build and retirement decisions. AURORA determines a net present value (NPV) for each candidate resource, and existing resource available for retirement, based on variable and fixed costs as well as energy, ancillary, and other revenue. The method seeks to select the resources that provide the most value to the system given the constraints. The formulation also includes internal constraints to limit the amount of changes in system capacity that can happen between each iteration. These are dynamically updated to help guide the solution to an optimal solution and promote convergence. This setting is used by PSE for the LTCE modeling process.
MIP Gap	Percentage as a decimal value	This setting controls the precision level tolerance for the optimization. Using the Default setting is generally recommended and will dynamically assign the MIP gap tolerance to be used based on the study precision, objective setting, and potential the size of the problem. When Default is not selected, a value (generally close to zero) can be entered; the smaller the value, the harder the optimization works to find solutions.
Max Solve Time	Minutes	This setting controls the time limit used for each of the LT MIP solves. Generally using the Default setting is recommended, and will dynamically set the time limit based on the estimated difficulty of the problem (in most cases about 30 minutes). If Default is not selected, a user-specified value can be entered. Note that if the time limit is reached, this may mean that results will not be perfectly reproducible, so generally a higher value is recommended.
Additional Plans to Calculate	Integer Value	When this value is greater than zero, AURORA will calculate additional plans after the final new build options and retirements have been determined. To do this a constraint is added to exclude the previous solutions and then another MIP is formulated and the solver returns its next best solution. The resource planning team sets this to zero.

ASSUMPTIONS FOR ALL AURORA MODELS. The LTCE modeling process is a subset of the simulations that PSE performs in AURORA. PSE keeps most of these settings consistent across all models in AURORA, including the LTCE process. Some adjustments may be made for sensitivities or simulations that are not converging properly. Figure G-17 describes the other settings used in AURORA.

Figure G-17: The General Settings Used in all AURORA Models

Setting	Value Type	Definition
Economic Base Year	Year	The dollar year that all currency is set to in the simulation. For consistency, PSE uses 2012 across all simulations through all IRP processes in AURORA. This is the reason that PSE converts all inputs into 2012$.
Resource Dispatch Margin	Percentage	A value used to specify the margin over the cost of the resource required to operate that resource. PSE sets this value to 5%.
Remove Penalty Adders from Pricing	Binary	When this switch is selected, the model will adjust the zonal pricing by removing the effect of the non-commitment penalty on uncommitted resources as well as the minimum generation back down penalty on committed or must run resources. These penalty adders are used in the LP dispatch to honor commitment and must run parameters; if this switch is selected the model fixes resource output at the solved level before deriving zonal pricing without the direct effect of the adders. PSE selects this setting.
Include Variable O&M in Dispatch	Binary	This option is used to control the treatment of variable operation and maintenance (O&M) expense. If selected, the variable O&M expense will be included in the dispatch decision of a resource. PSE selects this setting.
Include Emission Costs in Dispatch	Binary	This option allows the user to include the cost of emissions in the dispatch decision for resources. If not selected the cost of emissions will not be included in the dispatch decision for resources. PSE selects this setting when modeling CO_2 price as a dispatch cost.
Use Operating Reserves	Binary	This option determines whether the dispatch will recognize operating reserve requirements and identify a set of units to be used for operating reserve purposes. When this option is selected the model will select a set of units (when possible) to meet the requirement. PSE selects this setting.
Use Price Caps	Binary	This option allows the user to apply price caps to specific zones in the database. If this option is selected the model will apply specified price caps to the assigned zones. PSE selects this setting.

Resource Value Decisions

When solving for each time step of the LTCE model, AURORA considers the needs of the portfolio and the resources that are available to fill those needs. The needs of the portfolio include capacity need, reserve margins, effective load carrying capacity (ELCC) and other relevant parameters that dictate the utility's ability to provide power. If a need must be addressed, the model will select a subset of resources that are able to fill that need.
At that time step, each resource will undergo a small simulation to forecast how it will fare in the portfolio. This miniature forecast takes into account the operating life, capacity output and scheduled availability of the resource. Resources that are best able to fulfill the needs of the portfolio are then considered on the merits of their costs.

Resource costs include the cost of capital to invest in the resource, fixed operation and maintenance (O&M) costs, and variable O&M costs. Capital costs include the price of the property, physical equipment, transmission connections and other investments that must be made to acquire the physical resource. Fixed O&M costs include the costs of staffing and scheduled maintenance of the resource under normal conditions. Variable O&M costs include costs that are incurred by running the resource, such as fuel costs and maintenance issues that accompany use.

Once the costs of operating each resource are forecasted, they are compared to find which has the least cost while serving the needs of PSE. The goal of the LTCE model, an optimization model, is to provide a portfolio of resources that minimizes the cost of the portfolio.

Modeling Inputs

A number of input assumptions are necessary to parameterize the model. These assumptions come from a mix of public and proprietary sources and some are refined through PSE's stakeholder engagement process.

FORECASTS. Some attributes of the model cannot be captured in a single number or equation. Seasonal changes in weather, population behavior, and other trends that influence utility actions rely on highly time-dependent factors. To help provide these types of information into the model, a series of forecasts are included in the input assumptions. Forecasts help to direct overall trends of what will be affecting the utility in the future, such as demographic changes, gas prices and environmental conditions. These forecasts are not perfect representations of the future, which is impossible to provide. However, they provide a layer of volatility that helps the model reflect real-world conditions.

Figure G-18: Forecast Inputs and Sources

Input	Source	Description
Demand Forecast	Internal (see Chapter 6 and Appendix F)	Energy and peak demand forecast for PSE territory over the IRP planning horizon.
Electric Price Forecast	Internal (See Chapter 5 and above)	Output of the AURORA Electric Power Price Model.
Natural Gas Price Forecast	Forward Marks prices, Wood Mackenzie (see Chapter 5)	A combination of the Forward Marks prices and Wood Mackenzie long term price forecast.
Wind and Solar Generation	Internal PSE forecasts, NREL, resource developers	Solar and wind generation shapes dictate the performance of these renewable resources. Some forecasts are provided by PSE from existing wind projects. As a result of stakeholder recommendations, NREL data is used.

RESOURCE GROUPS. Resources are split into two groups, existing resources and generic resources.

Existing Resources: Existing resources are provided to the model as the base portfolio. Existing resources include resources that are already in operation and resources that are scheduled to be in operation in the future. Scheduled maintenance and outage dates, performance metrics and future retirement dates are provided to the model.

Generic Resources: Generic resources are the resources that are available to be added to the LTCE model. These resources are representations of real resources that may be acquired by the utility in the future. Information about the generic resources include the fuel used by the resources, costs and availability. Transmission information is also included based on the locations of the resources being modeled. Details of the generic resources modeled by PSE are included in Appendix D, and the final generic resource inputs are available in Appendix H. Simplifications are made to these resources in order to obtain representative samples of a certain resource group. For example, the modeling of every potential site that PSE may acquire a solar project would require prohibitive amounts of solar data from each individual location. To work around this issue, a predetermined site from different geographic regions to represent a solar resource in that area is used.

The specific generic resource characteristics have been developed in partnership with IRP stakeholders. As a result of stakeholder feedback, the costs of multiple resources were changed to reflect more current price trends, and new resources were added such as renewable/energy storage hybrid resources.

CAPITAL COST CALCULATIONS. The capital cost of a resource plays a large role in their consideration for acquisition by the model. However, the capital cost of a resource is not a one-time investment made at the time of acquisition. PSE must typically go into debt to obtain the purchasing power necessary to acquire a resource.

Every resource, once installed, has its own "revenue requirement." This revenue requirement is the amount of money that the utility must collect from ratepayers in order to cover the operating expenses of the resource in addition to the financing costs of the capital investment. The combined revenue requirement of all resources in the portfolio is the portfolio's total revenue requirement, which is the objective function that the LTCE model seeks to minimize.

The revenue requirement is broken down in the following equation:

$$\textbf{Revenue Requirement} = (\textbf{Rate Base} * \textbf{Rate of Return}) + \textbf{Operating Expenses}$$

Where:

The **Rate Base** is the amount of investment made in the plant devoted to the operating capacity of that plant. In the state of Washington, the **Rate Base** is valued as the original cost of the resource, minus the accumulated financial depreciation and deferred tax payments on the resource.

The **Rate of Return** is the predetermined return on investment that a utility will earn from payments made by ratepayers. When the **Rate Base** is multiplied by the **Rate of Return,** the result is the operating income requirement of the plant, which represents a combination of the capital costs and fixed O&M costs of the resource.

Operating Expenses of a resource are the variable O&M costs of that resource, including fuel and maintenance as a result of plant operation.

SOCIAL COST OF GREENHOUSE GASES. Per CETA requirements, PSE is including the social cost of greenhouse gases (SCGHG) as a cost adder as a part of the IRP process. PSE is modeling the SCGHG as a **planning adder**. However, PSE completed several portfolio sensitivities and electric price scenarios modeling the SCGHG as a variable dispatch cost as requested by stakeholders.

PSE models the SCGHG as a planning adder using the following methodology:

1. The LTCE model is run to determine portfolio build decisions over the modeling timeframe. Within the LTCE model, the SCGHG is applied as a penalty to emitting resources (i.e., fossil-fuel fired resources) during each build decision.

    a. The planning adder is calculated as such:
        i. AURORA generates a forecast of dispatch for the economic life of the emitting resource. This dispatch forecast is not impacted by the SCGHG to simulate real-world dispatch conditions.
        ii. The emissions of this dispatch forecast are summed for the economic life of the emitting resource and the SCGHG is applied to the total lifetime emissions.
        iii. The lifetime SCGHG is then applied as and adder that is amortized over the life of the project.
        iv. A new build decision is made based on the total lifetime cost of the resource.

2. The LTCE model results in a portfolio of new builds and retirements. Since the LTCE runs through many simulations a sampling method is used to decrease run time, so the final step is to pass the portfolio to the hourly dispatch model, which is capable of modeling dispatch decisions at a much higher time resolution. The hourly dispatch model is not capable of making build decisions, but will more accurately assess total portfolio cost to rate payers. Since the SCGHG is not a cost passed to rate payers, the SCGHG is not included as part of this modelling step.

Stakeholders have requested that the SCGHG be included as a **dispatch cost** at all modeling levels. PSE understands this approach as:

1. A long-term capacity expansion (LTCE) model is run to determine portfolio build decisions over the modeling timeframe. Within the LTCE model, the SCGHG is applied as a penalty to emitting resources during each build decision as a dispatch cost. This means that the total energy produced by the resource has decreased due the higher cost of dispatch.
2. The LTCE model results in a portfolio of new builds and retirements. Since the LTCE runs through many simulations a sampling method is used to decrease run time, so the final step is to pass the portfolio to the hourly dispatch model, which is capable of modeling dispatch decisions at a much higher time resolution. The hourly dispatch

model is not capable of making build decisions, but will more accurately assess total portfolio cost to rate payers. The SCGHG can either

a. be included in dispatch decisions to remain consistent with the LTCE model, or
b. not be included in the hourly dispatch.

PSE used the SCGHG as a **planning adder** for the LTCE simulations. However, PSE completed some portfolio sensitivities using the SCGHG as a **dispatch cost.** These portfolio sensitivities are included in Chapter 8.

FINANCIAL ASSUMPTIONS. As the portfolio modeling process takes place over a long-term timeline, assumptions must be made about the financial system that the resources will operate in.

Production Tax Credit Assumptions: The PTC is phased down over time: 100 percent in 2020, 80 percent in 2021, 60 percent in 2022, 40 percent in 2023, 60 percent in 2024 and 0 percent thereafter for projects with respective online dates. A project must have started before the end of 2020 and has four years to complete to receive the PTC. For projects for which construction started in 2016 & 2017, the online dates have been extended by an additional year to 2021 and 2022 respectively with 100 percent and 80 percent remaining unchanged. A project must meet the physical work test or show that 5 percent or more of the total cost of the project was paid during that construction-begin year. For example, if a project began construction or paid 5 percent or more in costs in the year 2020, it will receive the 60 percent PTC even if the facility doesn't go online until 2024. The PTC is received over 10 years and is given as a variable rate in dollars per MWh. All PTC values and eligibility are based on Congressional Research Service publication dated April 29, 2020, The Renewable Electricity Production Tax Credit: In Brief.

Investment Tax Credit Assumptions (ITC): The ITC is a one-time benefit based on the total capital cost invested in the project. The phase-down over time varies depending on the technology:

- Solar: 30 percent 2020-2023, 26 percent in 2024, 22 percent in 2025, and 10 percent in 2026 and thereafter.

The ITC benefit is based on the year that the project is complete. A project has four years to complete to receive the ITC. For example, if a solar project starts construction in 2021 but does not go online until 2025, it will receive a 22 percent tax credit based on the total capital cost. So, if the project costs $300 million, then the developer will receive $66 million in tax benefits.

Discount Rate: PSE used the pre-tax weighted average cost of capital (WACC) from the 2019 General Rate Case of 6.8 percent nominal.

Inflation Rate: The 2017 IRP uses a 2.5 percent escalation for all assumptions unless otherwise noted. This is the long-run average inflation rate that the AURORA model uses.

Transmission Inflation Rate: In 1996, the BPA rate was $1.000 per kW per year and the estimated total rate in 2015 is $1.798 per kW per year. Using the compounded average growth rate (CAGR) of BPA Point-to-Point (PTP) transmission service (including fixed ancillary service Scheduling Control and Dispatch) from 1996 to 2015, we estimated the nominal CAGR inflation rate to be 3.05 percent annually.

Gas Transport Inflation Rate: Natural gas pipeline rates are not updated often and recent history indicates that the rates are 0 percent. PSE has assumed zero inflation on pipeline rates because the major pipelines on which we operate have declining rate bases and major expansions will be incrementally priced. Growth in cost of service from operating costs and maintenance capital additions are expected to be offset by declines due to depreciation.

Transmission and Distribution (T&D) Costs: A transmission and distribution deferral value of $15.15/kW-year was included as a negative cost item in the resource value for distributed battery energy storage, demand response and demand-side resources. This is an internal PSE calculated number based on current project costs.

Model Documentation

As of September 2020, the version of AURORA being used by PSE is Aurora 13.4.1001.

An excerpt from the AURORA documentation:

Mathematical Framework (Risk Metric = Variance)

This next section describes the mathematical framework for the optimization in greater detail. It lays out how portfolio cost and risk are defined and how the LPs are performed to find the portfolios along the efficient frontier. For the notation in this section, assume that the word "resource" refers to either an Aurora resource or portfolio contract, and that the term "time period" refers to a specific time bucket as already explained above.

Portfolio Notation

Assume the following general notation:

1. There exist *r* candidate portfolio resources over *m* time periods.
2. For a portfolio selected from the set of *r* resources, the proportion of resource *j* held in the portfolio is denoted a_j. In this context, each a_j must lie in the unit interval, i.e. $\forall j, a_j \in [0,1]$.
3. <u>*a*</u> is the column vector $(a_1, a_2, \ldots, a_r)'$.
4. *I* is an identity matrix, with dimension indicated by context.
5. $E_{\alpha\beta}$ is an α by β array of 1s.

From each individual Aurora simulation, assume the following notation:

- In time period *i*, resource *j* has a total cost C_{ij}. This includes fuel costs, emissions costs, variable O&M costs, startup costs, and fixed costs.
- Resource *j* may also have capacity revenue in period *i,* denoted as RK_{ij}.
- The energy generated in period *i* by resource *j* is denoted G_{ij}.
- Portfolio demand in period *i* is denoted D_i.
- Portfolio capacity demand (annual peak demand) in year *y* is denoted DK_y.
- Average market price in period *i* is denoted p_i.
- Average capacity price in year *y* is denoted PK_y.
- Denote the following arrays:
    - *RK* is an *m* by *r* matrix, $\{RK_{ij}\}$.
    - *G* is an *m* by *r* matrix, $\{G_{ij}\}$.
    - <u>*p*</u> is the column vector $(p_1, p_2, \ldots, p_m)'$.
    - <u>*PK*</u> is the column vector $(PK_1, PK_2, \ldots, PK_m)'$.
    - <u>*D*</u> is the column vector $(D_1, D_2, \ldots, D_m)'$.
    - <u>*DK*</u> is the column vector $(DK_1, DK_2, \ldots, DK_m)'$.

With this notation, a portfolio is a triplet of values for the vectors $\underline{a}$, $\underline{D}$ and $\underline{DK}$. For Aurora portfolio optimization, $\underline{a}$ is the only one of the three variables subject to adjustment, $\underline{D}$ and $\underline{DK}$ being fixed (as calculated from the output data). Thus $\underline{a}$ becomes the vector of decision variables which will ultimately be solved for by the linear program when each portfolio is derived.

Defining Portfolio Cost and Variance

The total net cost of a portfolio in a run can be defined as the sum of four parts:

1. The cost of holding shares of resources held in the portfolio: $E_{1m}C\underline{a}$
2. The cost of market transactions required to balance the portfolio demand with the energy production of the resource shares held in the portfolio: $\underline{p}'(\underline{D} - G\underline{a})$
3. Optionally, if capacity prices and revenues are used, the cost of capacity corresponding to the portfolio demand: $\underline{PK}'\ \underline{DK}$
4. Optionally, if capacity prices and revenues are used, the negative capacity revenues from shares of resources held in the portfolio: $E_{1m}(RK)\underline{a}$

Thus the net portfolio cost *B* is:

$$B = E_{1m}C\underline{a} + \underline{p}'(\underline{D} - G\underline{a}) + \underline{PK}'\underline{DK} - E_{1m}(RK)\underline{a}\text{, or}$$

$$B = \left(E_{1m}(C - RK) - \underline{p}'G\right)\underline{a} + \underline{p}'\underline{D} - \underline{PK}'\underline{DK}$$

Define the vector $\underline{NC}'$ as $E_{1m}(C - RK) - \underline{p}'G$, and the final cost equation becomes

$$B = \underline{NC}'\underline{a} + \underline{p}'\underline{D} - \underline{PK}'\underline{DK}$$

There are three terms on the right side of this equation, only one of which involves $\underline{a}$. To simplify the relevant algebra, write the three terms as:

$$A_1 = \underline{NC}'\underline{a}$$

$$A_2 = \underline{p}'\underline{D}$$

$$A_3 = \underline{PK}'\underline{DK}.$$

Then the total portfolio cost can be written as:

$$B = A_1 + A_2 + A_3$$

The total portfolio variance can be written as *Var*(*B*) =

$$Var(A_1) + Var(A_2) + Var(A_3) + 2Cov(A_1, A_2) + 2Cov(A_1, A_3) + 2Cov(A_1, A_3)$$

Optimization Objective Functions

The optimization will use both cost and variance as objective functions for the linear program, so we need to be able to formulate both of these as a linear function of the decision variables vector a.

To do this for portfolio cost, we need to find the expected values which make up equation 1. The total expected portfolio cost becomes:

$$E[B] = E\left[\underline{NC}'\underline{a} + \underline{p}'\underline{D} - \underline{PK}'\underline{DK}\right] = E[\underline{NC}']\underline{a} + E\left[\underline{p}'\underline{D}\right] - E[\underline{PK}'\underline{DK}]$$

All the expected values in this expression are estimated by taking averages of the terms in brackets across the set of underlying Aurora runs. Note that when only one run has been performed, these expected value terms are simply the values from that run.

To describe the total portfolio variance as a linear function of a, we can expand equation 2 as follows:

$$Var(A_1) = \underline{a}'Cov(NC'E_{m1})\underline{a} \qquad (4)$$

$$Var(A_2) = Var\left(\underline{p}'\underline{D}\right) \qquad (5)$$

$$Var(A_3) = Var(\underline{PK}'\underline{DK}) \qquad (6)$$

$$2Cov(A_1, A_2) = 2\left(E_{1m}Cov\left(\underline{p}'\underline{D}, C\right)\underline{a} - E_{1m}Cov\left(\underline{p}'\underline{D}, RK\right)\underline{a} - Cov\left(\underline{p}'\underline{D}, \underline{p}'G\right)\underline{a}\right) \qquad (7)$$

$$2Cov(A_1, A_3) = 2\left(E_{1m}Cov(\underline{PK}'\underline{DK}, C)\underline{a} - E_{1m}Cov(\underline{PK}'\underline{DK}, RK)\underline{a} - Cov\left(\underline{PK}'\underline{DK}, \underline{p}'G\right)\underline{a}\right) \qquad (8)$$

$$2Cov(A_1, A_3) = 2Cov\left(\underline{p}'\underline{D}, \underline{PK}'\underline{DK}\right) \qquad (9)$$

The estimated variance of a scalar, such as in equations 5 and 6 above, is the sample variance of its value over the underlying Aurora runs. When vectors appear in the Cov() notation, the result is the estimated covariance matrix found by using the iterative data from the underlying Aurora runs. When two different arguments appear in Cov(), the implied covariance matrix will be d1-by-d2, where d1 is the length of the first vector argument, and d2 the length of the second. When the variance values are calculated, the unbiased sample estimate is always used.

Equation 4 is in a quadratic form which must be further transformed as a linear function of new decision variables. A linear approximation method using matrix diagonalization as well as a concept known as the principle of adjacent weights is used to be able to express Var(A1) as a linear function of a and other newly defined decision variables. The details of this technique are not delineated here. Testing has shown that the approximation technique used generally differs by less than .01% from the actual quadratic variance calculation.

AURORA Stochastic Risk Model

Deterministic analysis is a type of analysis where all assumptions remain static. Given the same set of inputs, a deterministic model will produce the same outputs. In PSE's IRP process, deterministic analysis identifies the least-cost mix of demand-side and supply-side resources that will meet need, given the set of static assumptions defined in the scenario or sensitivity. In this IRP, PSE modeled 27 sensitivities with a total of 37 portfolios which allowed PSE to evaluate a broad range of resource options and associated costs and risk. The sensitivity analysis is a type of risk analysis. By varying one parameter, we can isolate out how that one variable changes the portfolio builds and costs.

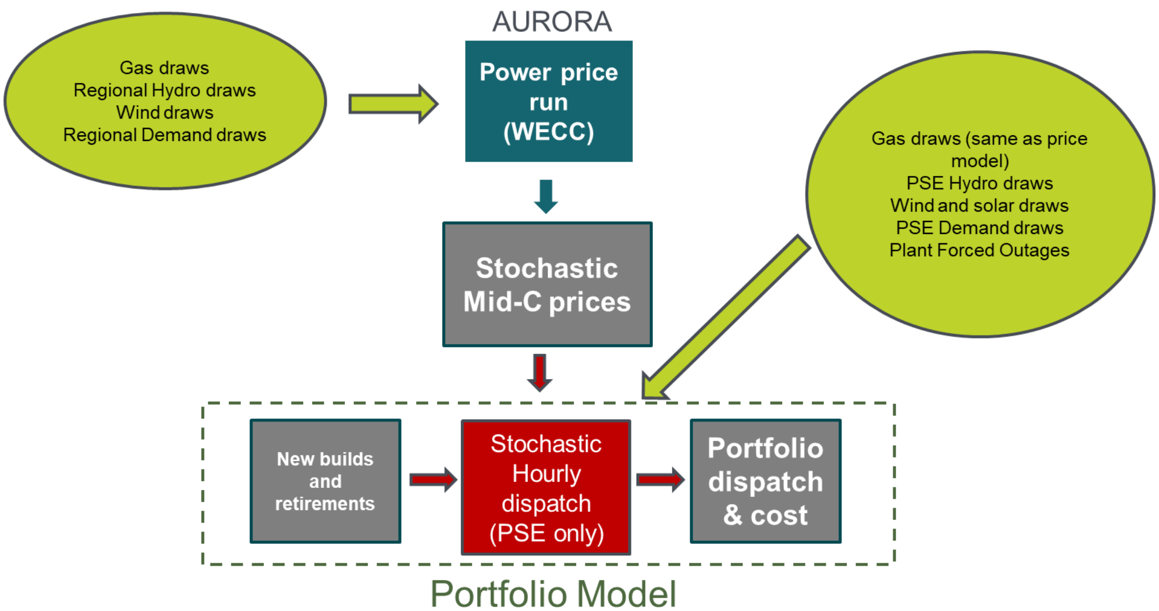
Stochastic risk analysis deliberately varies the static inputs to a deterministic analysis, to test how a portfolio developed in the deterministic analysis performs with regard to cost and risk across a wide range of potential future power prices, natural gas prices, hydro generation, wind generation, loads and plant forced outages. By simulating the same portfolio under different conditions, more information can be gathered about how a portfolio will perform in an uncertain future. The stochastic portfolio analysis is performed in AURORA.

The goal of the stochastic modeling process is to understand the risks of alternative portfolios in terms of costs and revenue requirements. This process involves identifying and characterizing the likelihood of different forecasts such as high prices, low hydro, etc., and the adverse impacts of their occurrence for any given portfolio. The modeling process used to develop the stochastic inputs is a Monte Carlo approach. Monte Carlo simulations are used to generate a distribution of resource energy outputs (dispatched to prices and must-take), costs and revenues from AURORA. The stochastic inputs considered in this IRP are electric power prices at the Mid-Columbia market hub, natural gas prices for the Sumas and Stanfield hubs, PSE loads, hydropower generation, wind generation, solar generation and thermal plant forced outages. This section describes how PSE developed these stochastic inputs.

Development of Stochastic Model Inputs

A key goal in the stochastic model is to be able to capture the relationships of major drivers of risks with the stochastic variables in a systematic way. One of these relationships, for example, is that variations in electric power prices should be correlated with variations in natural gas prices, contemporaneously or with a lag. Figure G-19 shows the key drivers in developing these stochastic inputs. In essence, long-term economic conditions and energy markets determine the variability in the stochastic variables.

Figure G-19: The Major Components of the Stochastic Modeling Process



PSE's stochastic model follows this process to simulate 310 futures of portfolio dispatch and cost.

1. The first step in PSE's stochastic process is generating electric price draws. Similar to the generating the deterministic wholesale price forecast, PSE uses Energy Exemplar's AURORA model to simulate resource dispatch to meet demand and various system constraints. Regional demand, gas price, hydro generation and wind generation are varied to generate the electric price draws. PSE uses the price forecast for the "Mid-C" zone as the wholesale market price in the portfolio model.
2. Next, we move to PSE's hourly portfolio dispatch model. The electric prices and natural gas price draws generated in the first step are pulled into the portfolio model.
3. PSE takes different portfolios (drawn from the deterministic scenario and sensitivity portfolios) and runs them through 310 draws that model varying power prices, gas prices, hydro generation, wind generation, solar generation, load forecasts (energy and peak) and plant forced outages. From this analysis, PSE can observe how robust or risky the portfolio may be and where significant differences occur when risk is analyzed.

Stochastic Electric Price Forecast

PSE uses Aurora, a production cost model that utilizes electric market fundamentals to generate the electric price draws. Aurora offers a Monte Carlo Risk capability that allows users to apply uncertainty to a selection of input variables. The variability of input assumptions can either be introduced into the model as an external data source or Aurora can generate samples based on user statistics on a key driver or input variable. This section describes the model input assumptions that were varied to generate the stochastic electric price forecast.

NATURAL GAS PRICES. PSE relied on the Aurora's internal capability to specify distributions on select drivers, in this case gas prices, to generate samples from a statistical distribution. The risk factor represents the level of adjustment to the base value for the specified variable for the relevant time period. To calculate the risk factor on gas prices, PSE calculated the correlation of gas prices from Sumas, Rockies (Opal), AECO, San Juan, Malin, Topock, Stanfield and PGE City Gate to Henry Hub using data from Wood Mackenzie's Spring 2020 Long Term View Price Update. The Low, Medium, and High gas prices were also evaluated for each hub to determine the average and standard deviation for each calendar month. The standard deviation as a percent of the mean for each calendar month and is used as an input to AURORA for risk sampling. Figure G-20 and G-21 below illustrate the annual draws and the levelized 20-year Sumas gas price $/mmbtu generated by the Aurora model.

Figure G-20: Annual Sumas Gas Price Draws ($/mmBtu)

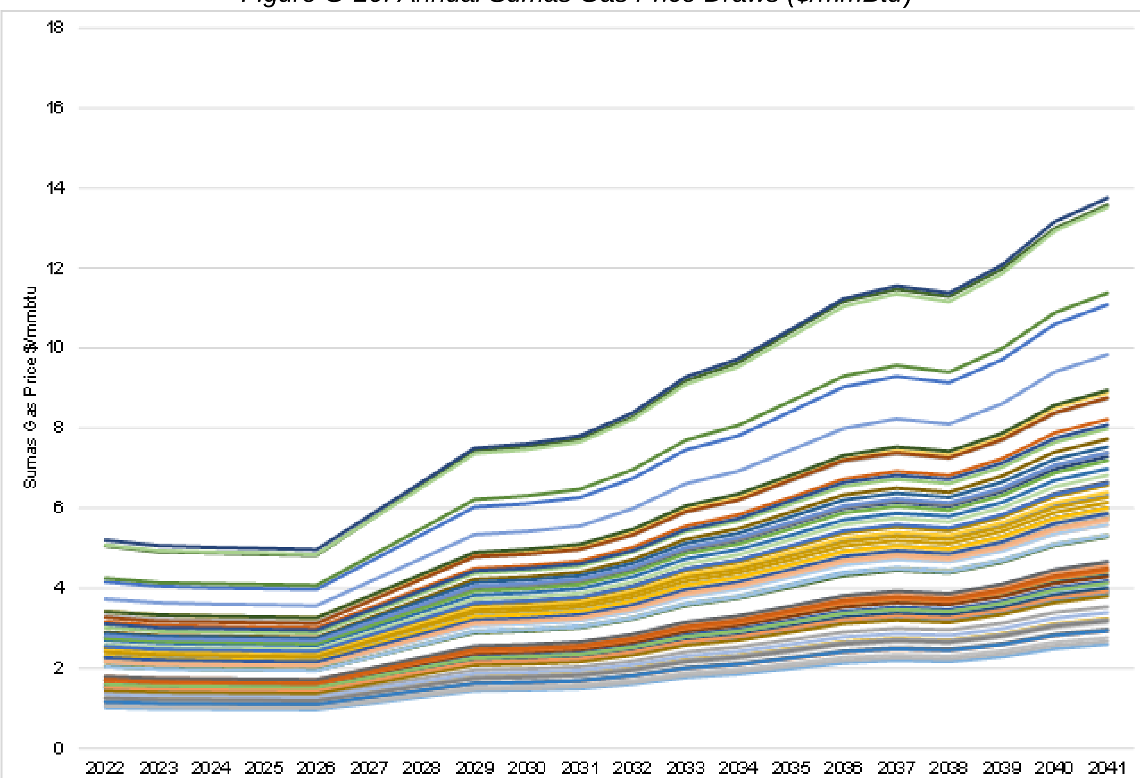
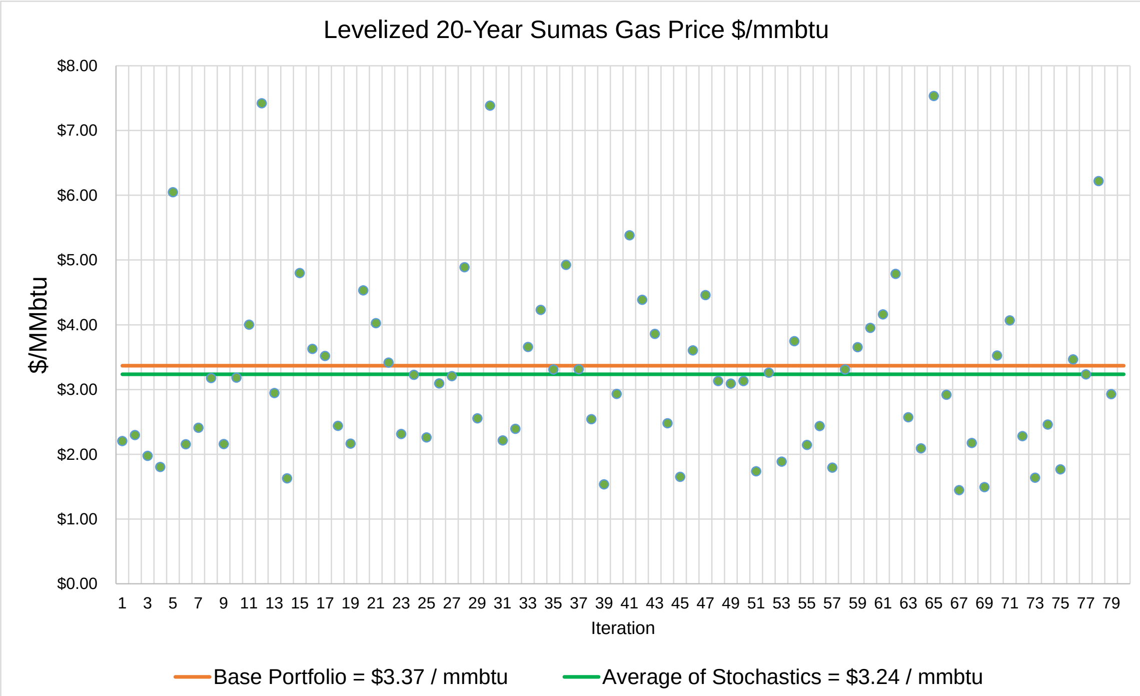


Figure G-21: Levelized 20-year Sumas Natural Gas Price $/mmbtu

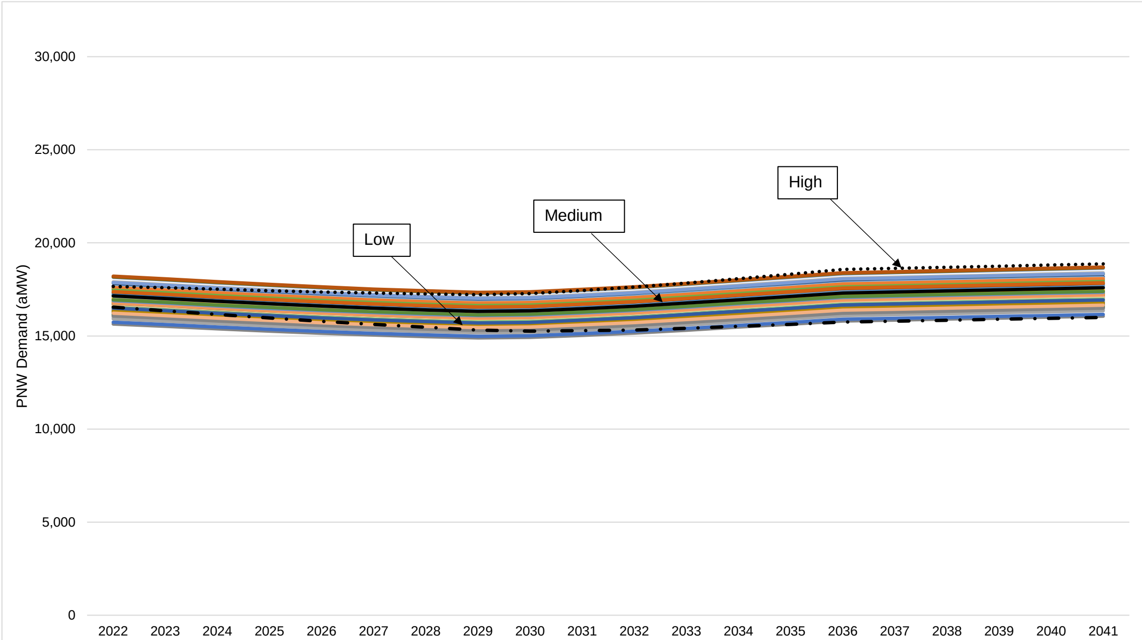


REGIONAL DEMAND. Similar to natural gas prices, PSE relied on the Aurora's internal capability to generate samples from a statistical distribution of demand. Low, Medium, and High regional demand forecasts used in the deterministic price forecasts were evaluated to determine the standard deviation as a percent of the mean for 24 years. Figure G-22: displays the 24-year Levelized Demand and the calculated standard deviation for the region. The standard deviation is used as an input to Aurora for the risk sampling of the entire WECC. Figure G-23 below illustrates the 80 draws of demand generated by Aurora for the Pacific Northwest.

Figure G-22: 24-year Levelized Demand for PNW

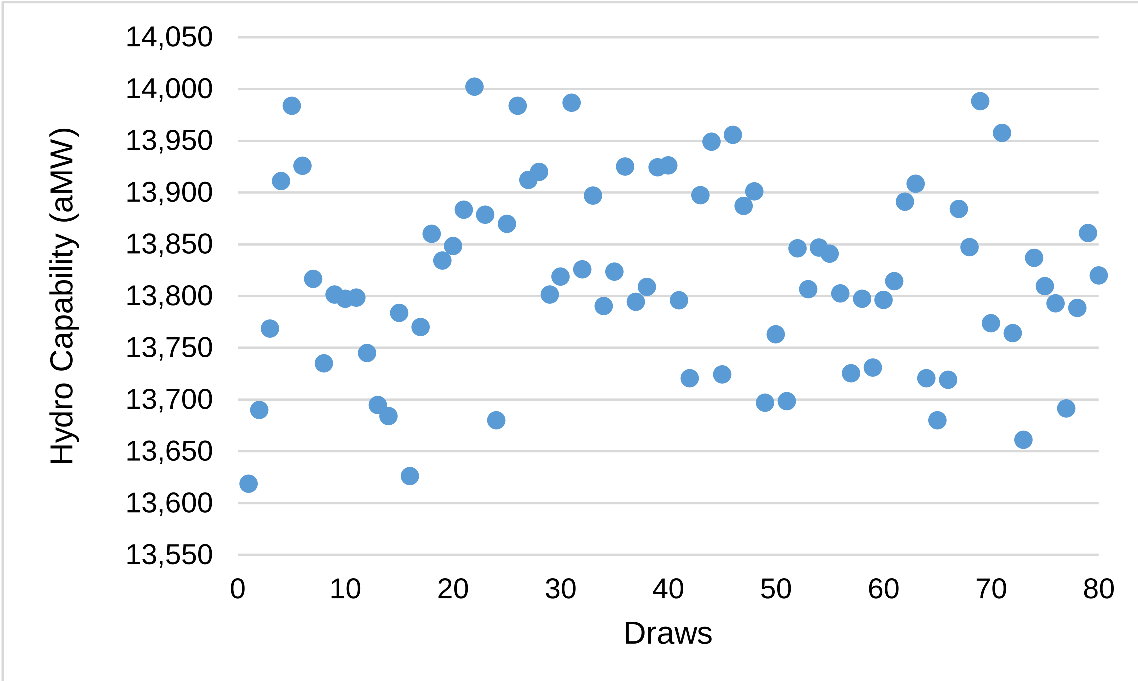
24 Yr Levelized Demand (PNW)	
Low (aMW)	15,820
Medium (aMW)	16,912
High (aMW)	17,833
Mean	16,855
St Dev	1,008
St Dev Pct	0.06

Figure G-23: Pacific Northwest Demand Draws (aMW)



HYDRO VARIABILITY. For the power price stochastics simulations, 80 iterations of possible hydro conditions were taken from the hydro data delivered in Energy Exemplar's default database for the Northwest states, British Columbia and California. The years included in this database are 1929 – 2008. The hydro database is provided by the Bonneville Power Administration (BPA) The BPA releases an updated dataset every 10 years, with the last release from 2012 containing the years 1929 – 2008. The Northwest Power Pool information relating to river operation according to the latest Biological Opinion is implemented. This data is summarized by AURORA Area and adjusted for non-reporting hydro generators. The 80-year hydro capability for the Pacific Northwest can be seen in in Figure G-24.

Figure G-24: Hydro Capability for the Pacific Northwest for 80 Hydro Years, 1929-2008.



WIND VARIABILITY. Energy Exemplar developed wind shapes in the default Aurora database relying primarily on generation estimates from the National Renewable Energy Laboratory's (NREL) Wind Integration National Database (WIND) 2014 Toolkit, using data from the years 2007 – 2012. The generation from clusters of NREL wind sites with similar geography and capacity factors were averaged together to form each of the delivered wind shapes. For each wind region, developed hourly shapes with capacity factors appropriate for each wind class ranging from a high of a 45 percent capacity to a low of a 25 percent capacity factor. For the Power Price Stochastics Run, all available hourly wind shapes for each state in the default database were identified and was the basis of randomly generating 80 iterations of wind data for each location.

STOCHASTIC ELECTRIC PRICE FORECAST RESULTS. AURORA forecasts market prices and operation based on the forecasts of key fundamental drivers such as demand, fuel prices, and hydro conditions. Using the risk sampling for Demand, Fuel and the pre-defined iteration set Hydro and Wind, Aurora is able to generate 80 iterations of power price forecast. PSE runs one price simulation for each of the 80 hydro years, which creates 80 price draws.

For the 2021 IRP, the annual and average power prices of the stochastic Power Price run are shown in Figure G-25 and G-26.

Figure G-25: Annual Power Price Stochastic Results

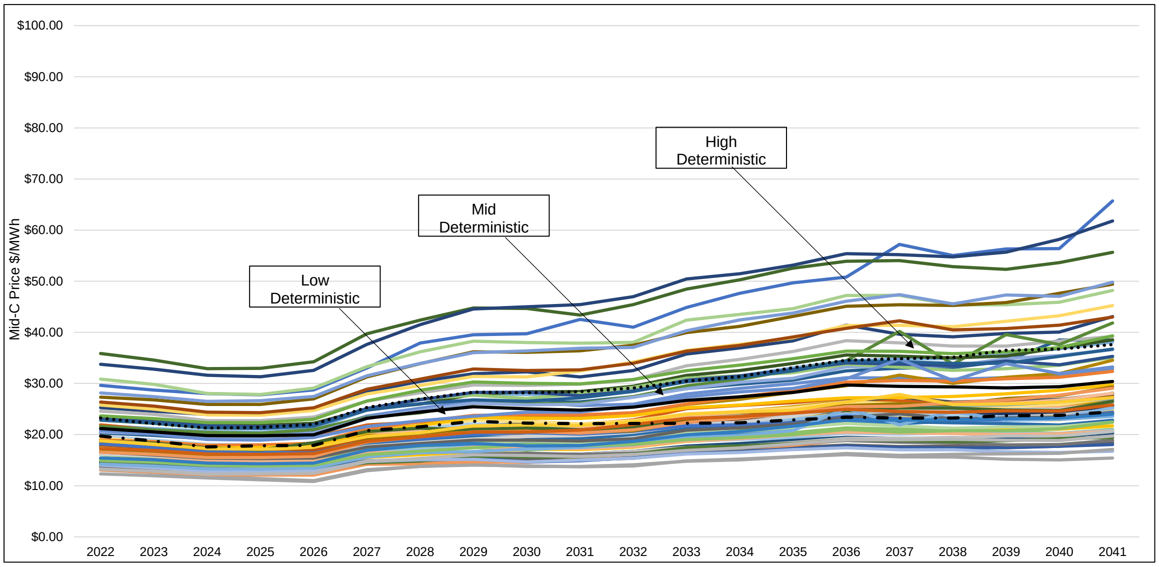
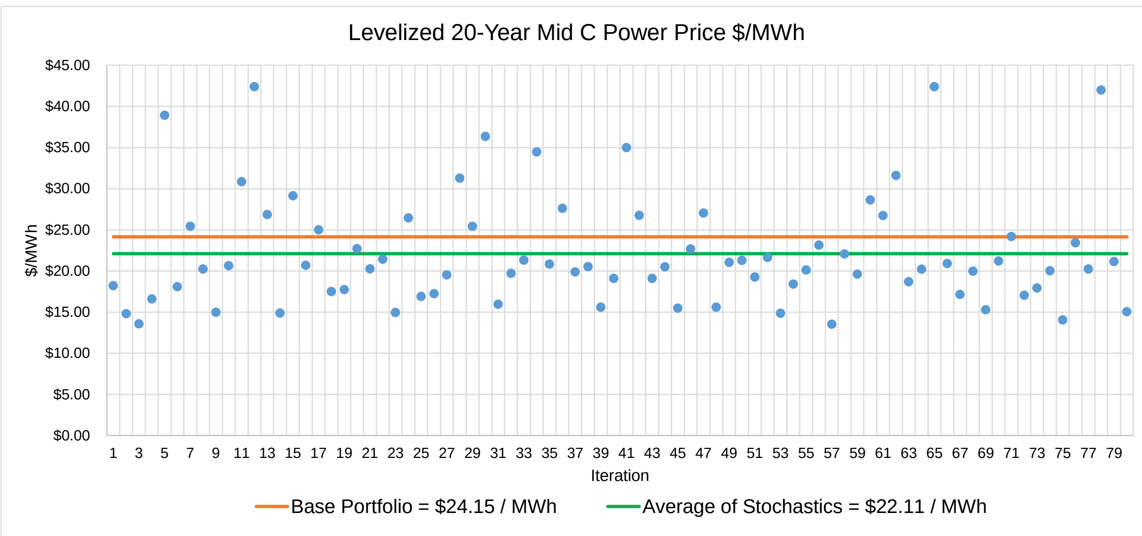


Figure G-26: The Stochastic Power Price Results



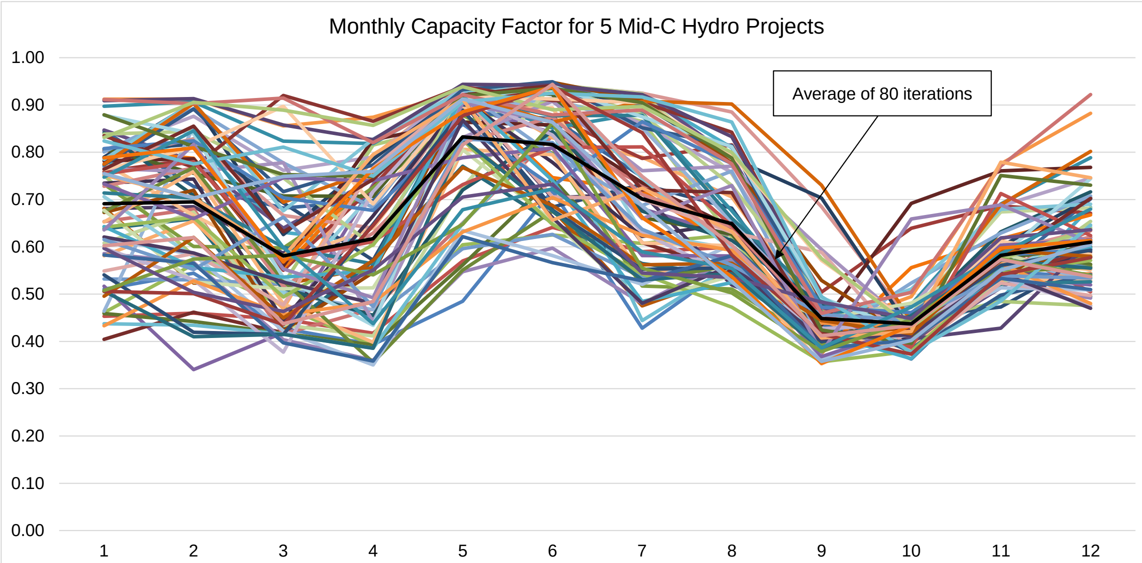
Stochastic Portfolio Model

PSE also uses Aurora for stochastic portfolio modeling and applies a pre-defined iteration set to modify the input data in the model. PSE take the portfolios (drawn from the deterministic scenario and sensitivity portfolios) and runs them through 310 draws that model varying power prices, gas prices, hydro generation, wind generation, solar generation, load forecasts (energy and peak), and plant forced outages. This section describes the model input assumptions that were varied to generate the portfolio dispatch and cost.

ELECTRIC AND NATURAL GAS PRICE. Electric price and natural gas inputs were discussed in the previous section. Each completed set of power prices is packaged with gas price and hydro inputs assumed when generating that particular power price forecast. This bundle of power prices, gas prices, hydro conditions are used as a set of inputs into the Stochastic Portfolio Model. By packaging the power price, gas price and hydro year together relationship between gas prices and Mid-C prices and the relationship between hydro and power prices are preserved. Since there are only 80 draws generated from Stochastic Electric Price Forecast, the electric price and natural gas were repeated 4 times to generate 310 draws.

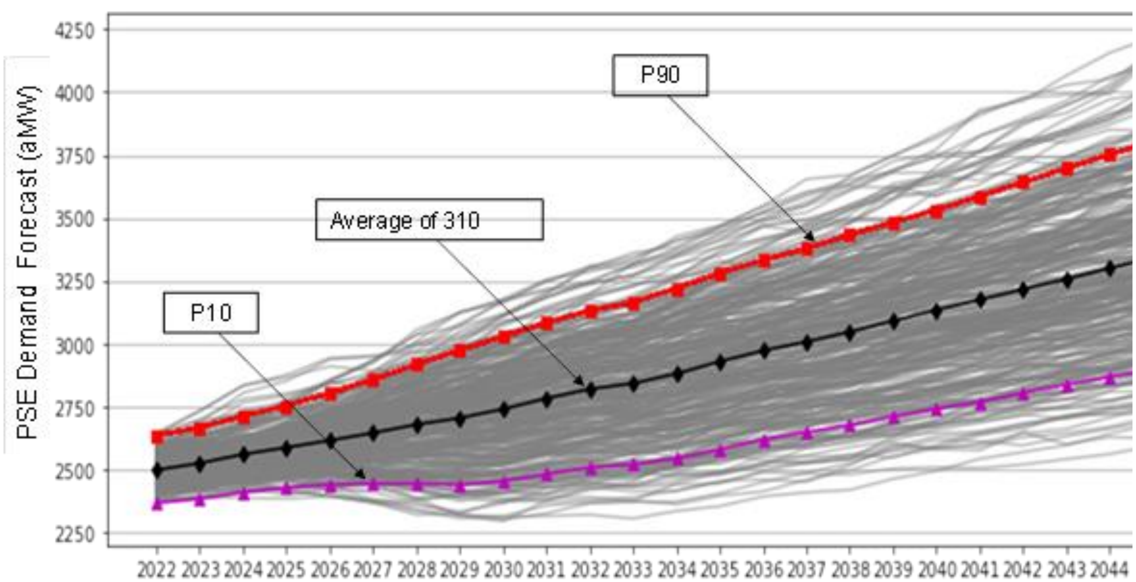
HYDRO VARIABILITY. PSE uses the same hydro data that was developed by the Bonneville Power Administration and used in BPA's rate cases. It is also the same hydro data that is used by the Northwest Power and Conservation council along with all the other utilities in the Pacific Northwest. BPA releases an updated dataset every 10 years of the natural streamflow data, with the last release from 2012 containing the years 1929 – 2008. While the natural streamflow data is only updated once every 10 years, a bi-annual study is performed to update for planned outages and any new or revised non-power restrictions and obligations (fish spill requirements, flood control elevations, etc.). The 80-year Mid-C Hydro data used in this study is also the same dataset used for PSE's 2020 Power Cost Only Rate Case. It is important to stay consistent with the other entities since we are all modeling the same hydro power projects. PSE in particular does not have a large dependence on owned or contracted hydro resources, so variations have a smaller effect on PSE's ability to meet demand. The hydro variations have a larger effect on the available market for short term purchases which is captured in the market risk assessment. Hydro output of all 80 hydro years can be seen in in Figure G-27. 80 hydro years is equivalent to 80 iterations and repeated 4 times to generate 310 draws.

Figure G-27: Hydro Output for All 80 Hydro Years, 1929-2008



PSE DEMAND. To generate the set of stochastic electric demand forecasts, the demand forecasts assume economic/demographic, temperature, electric vehicle and model uncertainties. The high and low demand forecasts are derived from the distribution of these stochastic forecasts at the monthly and annual levels. *A full explanation of the stochastic demand forecasts can be found in Appendix F, Demand Forecasting Models.* A comparison of all demand forecasts used in the stochastic modeling process can be found in Figure G-28*.*

Figure G-28: Demand Forecast Simulations – Annual Energy (aMW)



SAMPLING GENERIC WIND AND SOLAR SHAPES. For each generic solar and wind resource modeled in the 2021 IRP, 252 production curves were created from the years 2007-2012. The sets of production curves contain 42 curves from each year in order to allow correlated sampling across renewable outputs. For the deterministic modeling process, a representative curve was selected from each dataset to model the performance of a generic renewable resource. In the stochastic modeling process, each renewable resource will operate with a unique production curve drawn from the set 252. Across all renewable resources, the generation year is the same within an iteration. The consistency of the generation year allows the renewable generation to preserve large-scale weather trends that may affect multiple locations at once.

To create the 310 stochastic input sets, each of the 252 sets of renewable shapes was used. Once the first 252 stochastic input sets had been created, the first 58 sets of renewable shapes were reused to complete the rest of the stochastic inputs. Figure G-29 and G-30 show the seasonal capacity factors of the wind and solar curves. A full description of the wind and solar curves can be found in Appendix D.

Figure G-29: The Seasonal Capacity Factors of All Generic Wind Resources

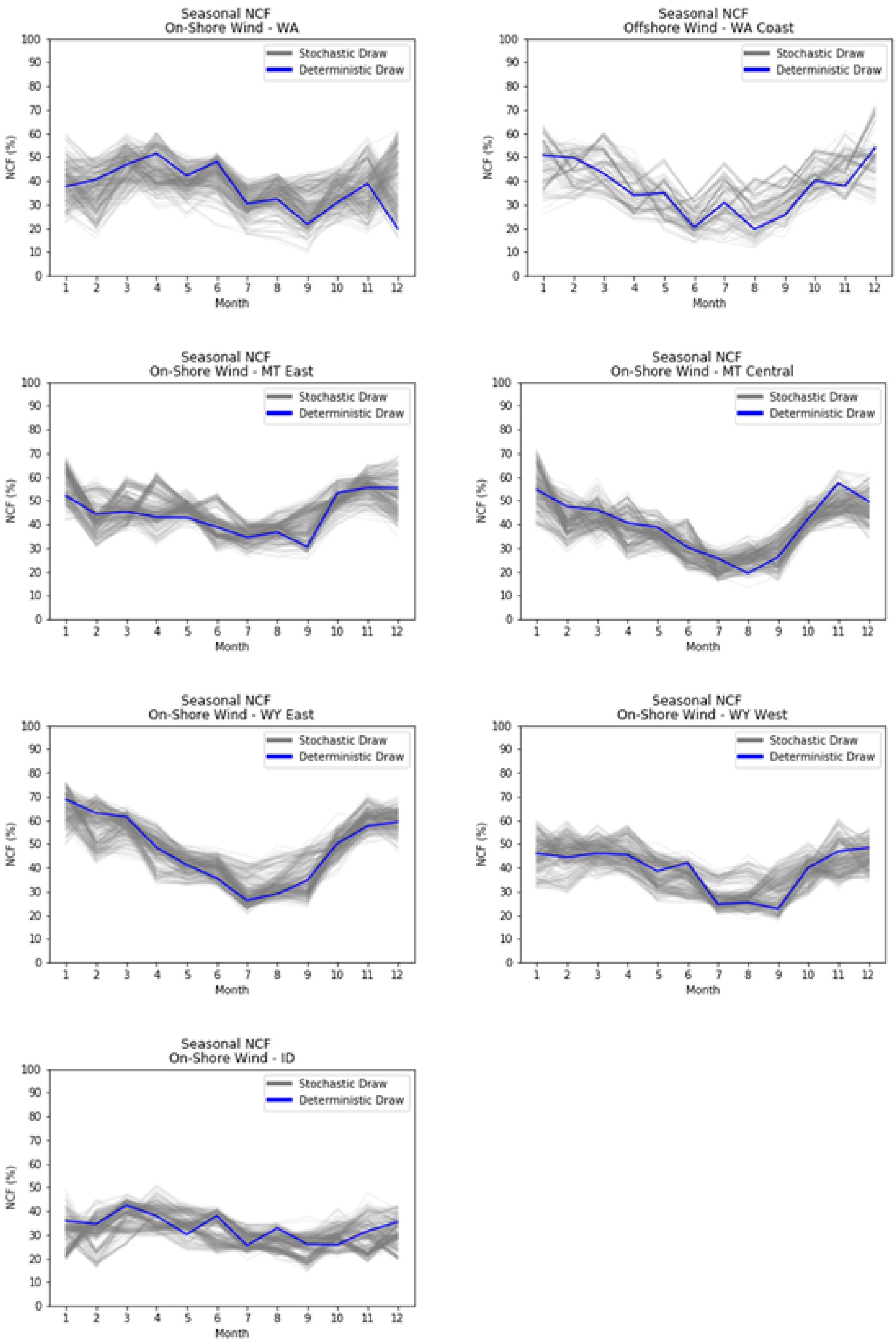
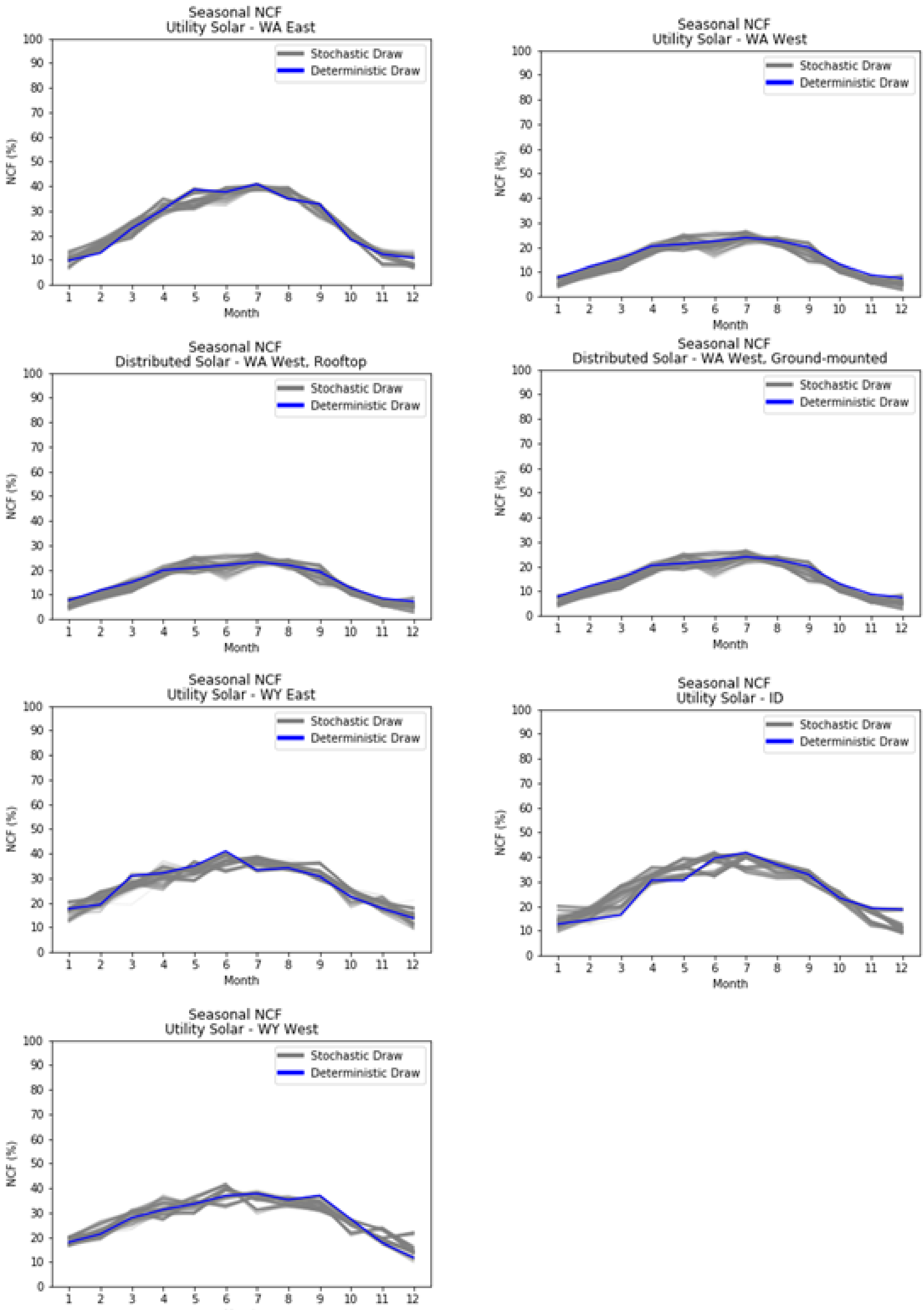


Figure G-30: The Seasonal Capacity Factors of All Generic Utility-scale Solar Resources



FORCED OUTAGE RATES. In AURORA, each thermal plant is assigned a forced outage rate. This value represents the percentage of hours in a year where the thermal plant is unable to produce power due to unforeseen outages and equipment failure. This value does not include scheduled maintenance. In the stochastic modeling process the forced outage rate is used to randomly disable thermal generating plants, subject to the minimum down time and other maintenance characteristics of the resource. Over the course of a stochastic iteration, the total time of the forced outage events will converge on the forced outage rate. The Frequency Duration outage method option allows units to fail or return to service at any time step within the simulation, not just at the beginning of a month or a day. The frequency and duration method assumes units are either fully available or completely out of service.

STOCHASTIC PORTFOLIO RESULTS. PSE tested the Mid Scenario portfolio, Sensitivity W Balanced Portfolio with Alternative Fuel for Peakers, Sensitivity WX Balanced Portfolio with Alternative Fuel for Peakers and Reduced Firm Market Access at Peak, and Sensitivity Z No DSR portfolio for the stochastic portfolio analysis. Stochastic results are discussed in Chapter 8, Electric Analysis and the data is available in Appendix H, Electric Analysis Inputs and Results.

Challenges and Next Steps

PSE is very conscious of model limitations and computer run times. We have discussed the idea of the varying hydro, wind and solar for each year in the planning horizon, but we need to ask ourselves, what is the benefit? What are we trying to model? PSE is trying to model the robustness of the portfolio. If we commit to a certain set of builds and the future is different than expected, will there be enough resources to meet needs? Total model run time for PSE's current stochastic electric price forecast model takes about 4 hours per draw to run the simulation, so that is 20,420 hours or 14 days to do the current simulations. By dividing the computer cores to run 4 parallel simulations, it takes about 4 days to complete 80 draws of price forecasts while not changing the hydro and wind draws for each year. PSE's current stochastic portfolio model takes about 1 hour per draw to run the simulation, so that is 310 hours or 12.9 days to do the current simulations. By dividing the computer cores and sharing out among 6 machines, it takes about 2 days to complete one portfolio simulation by keeping the portfolio static and not changing the hydro, wind and solar draws for each year. Once the machine is in use, PSE staff is unable to utilize the machine for other work processes.

Another question that came up was why the resource builds are fixed and do not vary by simulation. The Long Term Capacity Expansion Model which determines new resource builds and retirements takes from 18 to 24 hours to run one complete simulation for a portfolio. If PSE were to run the LTCE for each stochastic draw, then that would take 18 hours * 310 draws = 5,580 hours / 24 = 232 days to complete a portfolio optimization for all 310 possible futures. PSE is working with Energy Exemplar on model run times. At most, we might be able to decrease run times by half. This is why PSE does the sensitivity model, to isolate out several of the variables to see how that would affect portfolio builds and costs.

PSE acknowledges that inputs which vary year to year as well as simulation to simulation would provide a more nuanced analysis. PSE will explore opportunities to incorporate these changes into future IRP cycles. For the 2021 IRP, PSE suggests that static inputs as modeled still provide meaningful results and adequately bracket the upper and lower bounds of expected results as well as provide insight into various possible futures.

PLEXOS Flexibility Analysis Model

PLEXOS is used to estimate the impact of selected generic resources on system dispatch cost at a sub-hourly timeframe. PLEXOS is a sophisticated software platform that uses mathematical optimization combined with advanced handling and visualization to provide a high-performance, robust simulation system for electric power, water and gas. It is an hourly and sub-hourly chronological production simulation model which utilizes mixed-integer programming (MIP) to simulate electric power market, and to co-optimize energy and ancillary service provisions. The model first performs unit commitment and economic dispatch at a day-ahead level, and then redispatches these resources in real-time to match changes in supply and demand on a 15-minute basis.

For the sub-hourly cost analysis using PLEXOS, PSE created a current portfolio case based on PSE's existing resources, then tested each resource in the portfolio and calculated the cost difference in the real-time re-dispatch from the current portfolio case. The purpose of the flexibility analysis is to explore the sub-hourly flexibility needs of the portfolio and determine how new resources can contribute to those needs. Flexibility benefit = day-ahead (DA) dispatch costs – Intra-hour (IH or "real-time") dispatch costs. The flexibility benefit is then calculated as the total cost ($) / nameplate (MW) of resources as a fixed benefit per year ($/kw-year), and then added back to the resource in the capacity expansion model for making resource decisions.

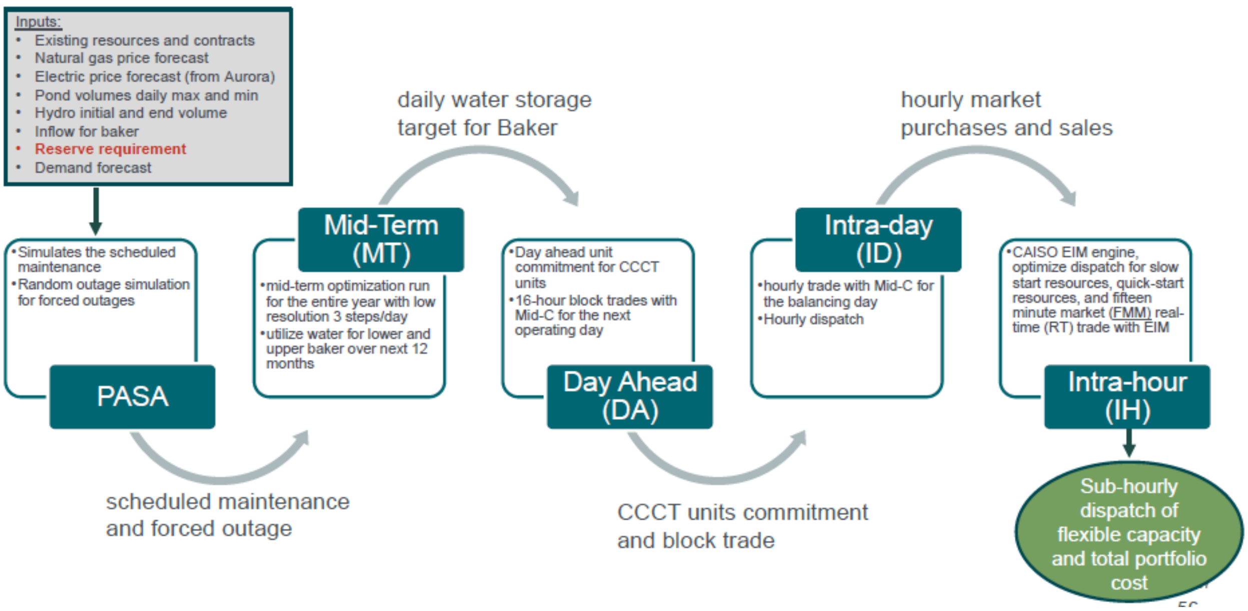
PLEXOS Simulation Phases

PSE utilized a five-stage simulation approach in PLEXOS. Each stage runs separately. The detailed inputs and outputs can be found in the Appendix H.

1. First, the Long-Term Projected Assessment of System Adequacy (PASA) stage incorporates scheduled maintenance and random outages. It simulates the availability of the generation units with the given forced outage rates and the scheduled maintenance information for the entire planning period, e.g., 25 years.
2. Then the Mid-Term stage runs a low-resolution version of the model that optimizes water usage at the Baker River Hydroelectric Project for the entire year with low resolution 3 steps/day, i.e., study year 2025.
3. The Day-Ahead stage then commits CCCT units on the hourly basis while also performing block trades with the Mid-C market on the basis of peak hour blocks and off peak hour blocks.
4. Next, the Intra-Day stage performs the hourly dispatch in the form of linear programming with the fixed commitments from the DA stage and trades on an hourly basis with the Mid-C market.

5. Finally, the Intra-Hour stage optimizes dispatch on the fifteen-minute. The PSE PLEXOS model also has the CAISO EIM engine. It can optimize dispatch for slow start resources, quick-start resources, and fifteen minute market (FMM) real-time (RT) trade with EIM. A full view of the PLEXOS modeling process can be viewed in Figure G-31.

Figure G-31: PLEXOS Simulation Phases



PLEXOS Model Inputs

CONTINGENCY RESERVES. Bal-002-WECC-1 requires balancing authorities to carry reserves for every hour: 3% of online generating resources and 3% of load to meet contingency obligations.

BALANCING RESERVES. Utilities must also have sufficient reserves available to maintain system reliability within the operating hour; this includes frequency support, managing load and variable resource forecast error, and actual load and generation deviations. Balancing reserves do not provide the same kind of short-term, forced-outage reliability benefit as contingency reserves, which are triggered only when certain criteria are met. Balancing reserves are resources that have the ability to ramp up and down instantaneously as loads and resources fluctuate each hour.

The balancing reserve requirements were assessed by E3 for two study years, using the CAISO flex ramp test. The results depend heavily on the Mean Average Percent Error (MAPE) of the hour-ahead forecasts vs real time values for load, wind and solar generation. Further discussion of reserves is in Chapter 7.

NATURAL GAS PRICES. For natural gas prices, PSE uses a combination of forward market prices and fundamental forecasts acquired in Spring 2020 from Wood Mackenzie. The natural gas price forecast is an input into the AURORA Electric Price Modeling and AURORA Portfolio Model. The natural gas price inputs as described in Chapter 5.

ELECTRIC PRICES. The electric price forecast was developed using AURORA (described above) and input into Plexos. This was used for the Mid-C day ahead and hourly trades. Using the Step Method, Plexos extrapolated the 15-minute electric prices for the EIM market.

DEMAND FORECAST. PSE's demand forecast described in chapter 6 is an input into Plexos using the monthly energy need (MWh) and peak need (MW). Using the Boundary Interpolate method, Plexos extrapolated the hourly and 15-minute loads using the 2019 historical load shapes.

Flexibility Benefit

To estimate the flexibility benefit of incremental resources, PLEXOS first runs the base case, which contains only PSE's current resource portfolio. Then, PLEXOS is run again with the addition of one new generic resource. The sub-hourly production cost result of the case with the base portfolio is then compared to the production cost of the case with the additional resource.

Any cost reduction to the portfolio is assumed to be attributed to the new resources. PSE tested each generic and thermal resource identified in the IRP and incorporated the flexibility benefit to the cost in the portfolio analysis. To avoid double counting, only cost reductions provided at the IH stage (incremental to DA stage cost savings) are added to the portfolio analysis.

The flexibility benefit calculation process is summarized below.

1. System cost savings between the two cases in the day-ahead stage
2. System cost savings between the two cases in the intra-hour stage
3. System cost savings between the day-ahead delta from (1) and intra-hour delta from (2)
4. Then the System cost savings from (3) divided by the nameplate of the resource to calculate them on a $/kW-year basis. This is called the flex benefit and a description with results is in Chapter 5.

The results for the flexibility benefit and flex violations are included in Appendix H.

2. AVOIDED COSTS

IRP Avoided Costs

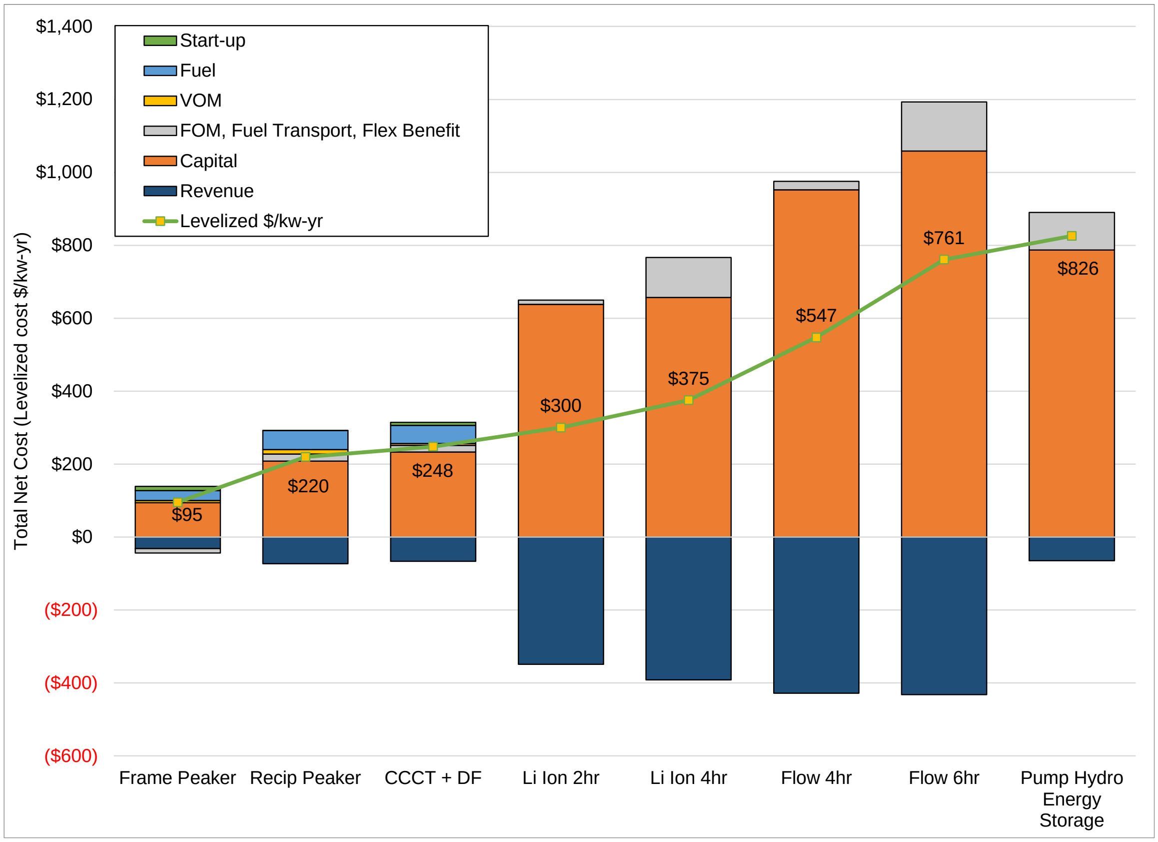
Consistent with WAC 480-100-620(13), the estimated avoided costs in this section provide only general information about the costs of new power supplies and is only used for planning purposes. This section includes estimated capacity costs consistent with the resource plan forecast, transmission and distribution deferred costs, GHG emission costs, and the cost of energy.

CAPACITY. Avoided capacity costs are directly related to avoiding acquisition of new capacity resources. The timing and cost of avoided capacity resources are tied directly to the resource plan. This represents the average cost of capacity additions (or average incremental costs) not marginal costs.

The indicative avoided capacity resource costs can be found in Appendix H. The costs are "net" capacity costs, meaning that the energy or other resource values have been deducted, using the Mid Scenario results. For example, frame peakers can dispatch into market when the cost of running the plant is less than market, which creates a margin that flows back to reduce customers' rates.

In addition to the avoided capacity cost expressed in $/kW-yr, the capacity credit of different kinds of resources needs to be specified. After specifying the annual avoided capacity resource costs by year, the avoided capacity costs include indicative adjustments to peak capacity value from the effective load carrying capability (ELCC) analysis in this IRP. The ELCC for a firm, dispatchable resource would be 100 percent, but different kinds of intermittent resources would have different peak capacity contributions. The capacity contributions used here are consistent with those described in Chapter 7. Figure G-32 below is the levelized cost of capacity (LCOC) compared across different resources. The LOC is discussed in Chapter 8.

Figure G-32: Net Cost of Capacity in the Mid Scenario Portfolio Model



PSE's preferred portfolio for the 2021 IRP is documented in Chapter 3 with explanations of why different resources are added to the portfolio. The first resource added to the portfolio for capacity needs is the frame peaker in 2026 at a cost of $95/kw-yr. Even though other resources are added to the portfolio in earlier years, they are added for other reasons, for example distributed energy resources (DERs) such as batteries. DERs make lower peak capacity contributions and have higher costs, but they play an important role in balancing utility-scale renewable investments and transmission constraints while also meeting local distribution system needs and improving customer benefits. Which is why the frame peaker is used as the avoided cost of capacity.

TRANSMISSION AND DISTRIBUTION (T&D). A transmission and distribution deferral value of $15.15/kW-year was included as a negative cost item in the resource value for distributed battery energy storage, demand response and Demand-Side resources. This is an internal PSE calculated number based on current project costs.

GHG EMISSIONS. PSE relies on market purchases to help balance the portfolio, so the avoided emissions from added new non-emitting resources is from unspecified market purchases.

Section 7 of E2SB5116, paragraph 2 states to use 0.437 metric tons CO_2/MWh for unspecified market purchases. The emission cost is calculated as follows:

SCGHG ($/ton) * 0.437 (tons/MWh) = emission cost ($/MWh)

Figure G-33 below is the emission cost adder in dollars per MWh.

Figure G-33: SCGHG Cost Adder

(Nominal $/MWh)	
2022	36.10
2023	37.58
2024	39.11
2025	41.30
2026	42.96
2027	44.67
2028	46.44
2029	48.27
2030	50.17
2031	52.12
2032	54.15
2033	56.24
2034	58.41
2035	60.65
2036	62.96
2037	66.17
2038	68.66
2039	71.23
2040	73.89
2041	76.64
2042	79.48
2043	82.42
2044	85.45
2045	88.58

ENERGY. PSE relies on market purchases to help balance the portfolio, so the avoided energy is market purchases. Therefore, PSE's avoided energy costs are clearly avoiding Mid-C market purchases. Peakers are capable of generating energy, so they temper PSE's exposure to market prices, at least when market heat rates (the spread between natural gas prices and power prices) increase. This means using a forecast of market prices could tend to overstate avoided energy costs during some hours – but only for short periods.

Figure G-34 shows the forecast of average monthly power prices and forecast of average annual market power prices at Mid-C for the Mid Scenario. This is the set of avoided energy costs PSE suggests would be the most informative for potential suppliers. The electric price also included in Appendix H.

Schedule of Estimated Avoided Costs for PURPA

This schedule of estimated avoided cost, as prescribed in WAC 480-106-040 identifies the estimated avoided costs for qualifying facilities and does not provide a guaranteed contract price for electricity. The schedule only identifies general information to potential respondents about the avoided costs. The schedule of estimated avoided costs includes the following two tables:

Figure G-34: 2022-2041 Avoided Energy Costs based on the Company's forecast of market prices for the Mid-C Market in PSE's 2021 Integrated Resource filed April 1st, 2021, pursuant to WAC 480-106-040(a).

Figure G-35: 2021-2041 incorporates the avoided capacity costs as estimated in the Company's 2021 Integrated Resource Plan. The 2021 IRP was filed on April 1, 2021. Pursuant to WAC 480-106-040(b)(ii), the 2021 IRP first capacity addition is 2026, so results for 2022-2025 are replaced with the "projected fixed costs of a simple-cycle combustion turbine."

Figure 34: 2021 IRP Forecast of Mid-C Market Prices

(Nominal $/MWh)													
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg.
2022	26.56	27.65	20.55	15.10	9.49	11.31	21.01	22.88	24.31	23.59	24.69	27.53	21.19
2023	25.24	26.50	19.77	14.79	9.70	10.29	20.13	21.93	23.68	23.11	24.42	27.09	20.53
2024	24.49	25.82	18.79	13.88	7.17	9.23	18.46	22.35	24.00	22.97	24.39	26.06	19.79
2025	24.49	25.82	18.97	12.83	7.53	9.73	18.21	22.47	24.22	22.79	23.80	26.50	19.75
2026	24.38	26.73	18.20	13.87	7.99	9.55	18.67	22.57	24.01	23.09	23.99	26.99	19.97
2027	28.08	28.91	19.71	15.44	9.14	10.75	22.01	26.84	28.62	28.87	29.00	31.20	23.19
2028	28.71	29.47	19.64	16.52	9.08	11.20	23.79	28.14	32.15	31.02	30.01	33.37	24.42
2029	29.33	31.29	19.63	20.07	8.87	11.50	23.61	30.20	35.24	32.07	28.96	34.85	25.44
2030	29.05	30.29	18.28	18.75	8.06	10.96	22.71	29.93	34.66	32.94	30.73	34.61	25.05
2031	28.42	30.42	18.22	18.19	8.55	11.12	22.13	29.98	34.53	32.65	29.03	34.49	24.78
2032	28.24	29.21	18.31	19.43	10.21	10.67	23.05	29.05	33.67	34.86	32.28	35.65	25.38
2033	29.08	31.54	19.17	19.67	9.61	11.64	24.84	29.95	34.57	37.49	36.03	37.07	26.69
2034	29.79	32.26	19.17	19.69	10.51	12.34	27.12	30.25	36.25	37.68	35.17	38.81	27.40
2035	31.00	35.33	19.95	22.93	11.60	12.60	27.03	32.04	37.97	36.64	32.09	40.27	28.25
2036	31.90	35.40	20.49	21.57	11.51	13.52	29.25	34.32	39.07	38.76	38.04	42.85	29.71
2037	32.89	35.55	19.90	20.06	11.58	12.92	30.46	34.47	38.51	38.58	35.59	42.87	29.43
2038	33.05	34.31	19.61	20.59	12.34	12.73	30.02	34.49	38.54	38.11	34.60	43.72	29.33
2039	31.29	33.46	18.20	19.01	10.72	12.48	30.87	34.28	40.25	38.63	36.81	43.64	29.12
2040	31.22	33.69	17.21	18.62	10.00	12.67	30.73	33.44	41.90	38.88	37.62	46.67	29.38
2041	32.16	35.50	18.23	21.07	10.60	12.79	29.37	38.67	45.79	37.02	35.39	48.41	30.39

Figure 35: 2021 IRP Forecast of Mid-C Market Prices

(Nominal $/kw-yr)			
	Baseload Resource	Wind Resource	Solar Resource
2022	$ 95.27	$ 16.96	$ 3.81
2023	$ 95.27	$ 16.96	$ 3.81
2024	$ 95.27	$ 16.96	$ 3.81
2025	$ 95.27	$ 16.96	$ 3.81
2026	$ 95.27	$ 16.96	$ 3.81
2027	$ 95.27	$ 16.96	$ 3.81
2028	$ 95.27	$ 16.96	$ 3.81
2029	$ 95.27	$ 16.96	$ 3.81
2030	$ 95.27	$ 16.96	$ 3.81
2031	$ 95.27	$ 14.67	$ 3.43
2032	$ 95.27	$ 14.67	$ 3.43
2033	$ 95.27	$ 14.67	$ 3.43
2034	$ 95.27	$ 14.67	$ 3.43
2035	$ 95.27	$ 14.67	$ 3.43
2036	$ 95.27	$ 14.67	$ 3.43
2037	$ 95.27	$ 14.67	$ 3.43
2038	$ 95.27	$ 14.67	$ 3.43
2039	$ 95.27	$ 14.67	$ 3.43
2040	$ 95.27	$ 14.67	$ 3.43
2041	$ 95.27	$ 14.67	$ 3.43
2042	$ 95.27	$ 14.67	$ 3.43
2043	$ 95.27	$ 14.67	$ 3.43
2044	$ 95.27	$ 14.67	$ 3.43
2045	$ 95.27	$ 14.67	$ 3.43

2021 PSE Integrated Resource Plan

H

Electric Analysis Inputs and Results

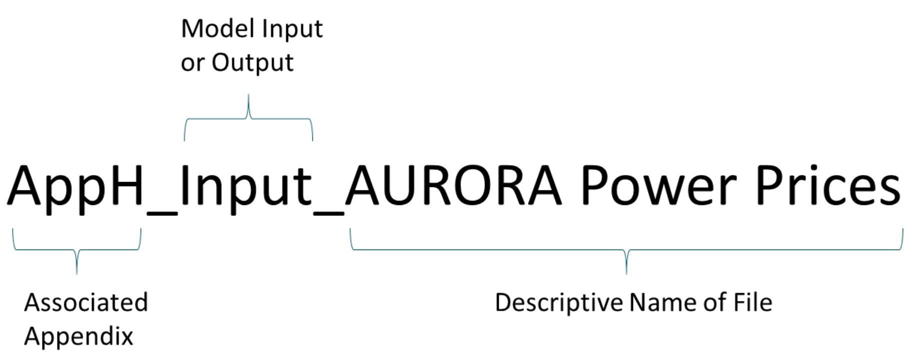
This appendix provides modeling inputs and outputs, as well as guidance for navigating the provided files.

Contents

1. 2021 IRP ELECTRIC ANALYSIS FILES

For the 2021 IRP, PSE is providing Microsoft Excel files containing input and output data in separate files instead of data tables directly in the IRP report. The direct access to the data provides usable files for stakeholders as opposed to static tables in a PDF format. Technical limitations on how PSE is able to submit files to the WUTC and host files online for stakeholder access has prevented PSE from keeping the files organized in a series of folders. To overcome this, a descriptive naming system has been developed in order to identify different files. Figure H-1 provides an example of how the provided files will be named. The same format is used for files from Appendix I, Natural Gas Analysis Results. Each Excel file also contains a "Read_Me" sheet with specific details related to the data contained in that file.

Figure H-1: Naming Conventions for Appendix H and Appendix I Files



2. MODELING INPUTS

Aurora Portfolio Model Inputs

The AURORA Long Term Capacity Expansion (LTCE) Portfolio Model files contain the data used in AURORA that PSE is able to share publicly. This includes generic resource assumptions, financial assumptions and specific settings used in AURORA. Figure H-2 provides a list of AURORA input files provided in this IRP.

Figure H-2: AURORA Portfolio Model Input File Names

File Names	Description
AppH_Input_AURORA LTCE Inputs	Contains inputs for the AURORA LTCE model, including generic resource assumptions and modeling parameters. Existing resource information is not included.
AppH_Input_AURORA LTCE Hourly Data	Contains the hourly data inputs of the AURORA LTCE model for generic resources and DSR programs.
AppH_Input_AURORA Power Prices	Contains the results of the hourly power price model, which is used as the power price inputs for other models.
AppH_Input_Demand Forecast	Contains the annual summary of PSE's demand forecasts used in the 2021 IRP.

LTCE INPUTS. This file contains the non-hourly inputs into the AURORA LTCE model, including generic resource assumptions and other modeling parameters. Confidential information regarding PSE's existing resources and other assets has been removed. All dollar values that are entered into AURORA are in 2012 dollars. More documentation of the AURORA modeling process can be found in Chapter 8 and Appendix G.

LTCE HOURLY DATA. This file contains the hourly data inputs for generic renewable resources and DSR in the AURORA LTCE model. Each hourly dataset has 8,784 entries, one for every hour of a leap year. Non-leap years exclude February 29th. More information about generic resources can be found in Chapter 5 and Appendix D. More information about DSR bundles can be found in Chapter 5 and Appendix E.

POWER PRICES. This workbook contains all of the hourly power price data developed for this IRP. For sensitivities that change the hourly dispatch, a new hourly price forecast is required. The AURORA power price forecast is run using the conditions of the scenario or sensitivity. Yearly and monthly prices are averages of those periods, and all prices are in $/MWh. More information about power prices can be found in Chapters 5 and Appendix G.

DEMAND FORECAST. This workbook contains the annual demand forecast data for the Electric and Gas systems. The forecasts include base and peak demand for the 2021 IRP timeline, 2022-2045.

CO_2 Prices

The CO_2 Prices file contains the calculations of the Social Cost of Greenhouse Gases (SCGHG) used during the 2021 IRP. Figure H-3 provides the name of this file.

Figure H-3: CO_2 Prices File Name

File Name	Description
AppH_Input_Carbon Price	Contains the calculations for the SCGHG values used in the 2021 IRP.

CARBON PRICE. This workbook contains PSE's calculations for converting the SCGHG into a format compatible with AURORA. This includes the base SCGHG calculation and the H.R. 763 SCGHG calculation used in Electric Sensitivity L.

Demand-side Resource (DSR) Data

These files contain the energy savings, costs and peak contributions of the DSR data in the Mid portfolio and Sensitivities F, G and H. Values that are broken down by sector (Industrial, Commercial, Residential) are recombined before being used in any model. The addition of these breakdowns was provided by Cadmus and are included in the files, but were not used separately in the 2021 IRP. Peak contributions are selected from the December values of the peak datasets to align with the PSE design system peak. The results of the electric DSR sensitivities can be found in Chapter 8. Figure H-4 provides the file names of these datasets. More information about the DSR data can be found in Appendix E.

Figure H-4: Electric System DSR Dataset File Names

File Names	Description
AppH_Input_Electric DSR Base	Contains the conservation bundles, codes and standards (C&S), combined heat and power (CHP), and Solar DSR outputs for the electric system.
AppH_Input_Electric DSR 6Yr	Applies a 6-Year ramp rate to conservation measures implemented in the DSR dataset instead of 10 years.
AppH_Input_Electric DSR NEI	Includes additional non-energy impacts in the energy savings of the bundles.
AppH_Input_Electric DSR SDR	Applies a 2.5% discount rate to the conservation measures.

BASE ELECTRIC DSR DATA. Contains the conservation bundles, codes and standards (C&S), combined heat and power (CHP) and Solar DSR outputs for the electric system.

ELECTRIC SENSITIVITY F, 6-YEAR RAMP RATE. Applies a 6-year ramp rate to conservation measures implemented in the DSR dataset instead of 10 years.

ELECTRIC SENSITIVITY G, NON-ENERGY IMPACTS. Includes additional non-energy impacts in the energy savings of the bundles.

ELECTRIC SENSITIVITY H, 2.5% SOCIAL DISCOUNT RATE. Applies a 2.5% discount rate to the conservation measures.

AURORA Generic Wind and Solar Shapes

The generic wind and solar capacity factor shapes used to model utility-scale renewable resources all have the same format, which is described below. Figure H-5 provides the file names of these datasets.

Figure H-5: Generic wind and Solar Shape File Names

File Names	Description
AppH_Input_WY Anticline Solar	Hourly input data for the WY Anticline solar resource.
AppH_Input_ID Solar	Hourly input data for the ID solar resource.
AppH_Input_ID Wind	Hourly input data for the ID wind resource.
AppH_Input_MT Central Wind	Hourly input data for the MT Central wind resource.
AppH_Input_MT East Wind	Hourly input data for the MT East wind resource.
AppH_Input_Offshore Wind	Hourly input data for the Offshore wind resource.
AppH_Input_WA East Solar	Hourly input data for the WA East solar resource.
AppH_Input_WA East Wind	Hourly input data for the WA East wind resource.
AppH_Input_WY East Wind	Hourly input data for the WY East wind resource.
AppH_Input_WY West Solar	Hourly input data for the WY West solar resource.
AppH_Input_WY West Wind	Hourly input data for the WY West wind resource.

Each solar and wind shape file contains four different tabs. Each tab is titled with a combination of "Stochastic" or "Representative" with "8760" or "8784". Figure H-6 explains the meaning of each part of the title.

Figure H-6: Naming Conventions for the Tabs in Each Renewable Generation File

Name	Meaning
Stochastic	This dataset contains 252 capacity factor profiles of the resource location for use in the stochastic modeling process.
Representative	This dataset contains the representative capacity factor profile of the resource location that was used in the deterministic portfolio model.
8760	Each capacity factor curve in this dataset contains 8760 hours, which corresponds to a non-leap year.
8784	Each capacity factor curve in this dataset contains 8760 hours, which corresponds to a leap year. The generation curves are the same as the non-leap year curves, with the exception that the February 28th values are copied to February 29th.

Each tab has the following values:

Index: Column A, the 0-index of all data entries.

Month, Day, Hour: Date and time values for the hours beginning at each time step. (1,1,0 is the January 1st hour beginning at Midnight)

NREL Site ID and Year*:* The header for the capacity factor column represents the NREL site ID and year the data was collected ("75703_2009" is from site ID 75703 in the year 2009).

A detailed explanation of the generic renewable resource generation profiles can be found in Appendix D.

3. MODELING OUTPUTS

AURORA

The AURORA output files contain the AURORA output data that PSE is able to share publicly. Figure H-7 provides the file names of these datasets.

Figure H-7: AURORA Output Files

File Names	Description
AppH_Output_Portfolio Output Summary	Contains an overview of the output data from the AURORA LTCE and hourly dispatch models.
AppH_Output_Levelized Resource Costs	Contains the calculations of the levelized costs of new resources in the 2021 IRP.
AppH_Output_Stochastics Results	Contains an overview of the results from the AURORA stochastic model.

PORTFOLIO OUTPUT SUMMARY. This workbook contains an overview of the output data from each electric portfolio modeled. The portfolio build data, emissions, annual revenue requirements, customer benefit indicators and overall portfolio costs are included. Plotting functionality is included for easy comparison between datasets. The analyses of the electric portfolios can be found in Chapter 8.

LEVELIZED RESOURCE COSTS. This workbook contains the calculations for the levelized costs of new resources in the 2021 IRP. The information from the raw data is processed in the resource-specific tabs. The processed data is then added to the charts and data summaries. More information on the levelized costs of resources can be found in Chapter 8.

STOCHASTIC MODELING RESULTS. This workbook contains the tables, charts and data from the AURORA stochastic modeling process used in the 2021 IRP. The portfolios examined in the stochastic modeling process are the Mid Scenario and Sensitivities W, WX, and Z. A full description of the stochastic portfolio analysis can be found in Chapter 8 and Appendix G.

PLEXOS

The PLEXOS output files contain the PLEXOS output data that PSE is able to share publicly. Figure H-8 provides the file names of these datasets.

Figure H-8: PLEXOS Output Files

File Names	Description
AppH_Output_Flex Benefits	Contains the calculation of the generic resource flexibility benefits using output data from the PLEXOS Flexibility Analysis model.
AppH_Output_Flex Violations	Contains data from the flexibility violations that occurred in the PLEXOS Flexibility Analysis model.

2025 FLEXIBILITY BENEFITS. This workbook contains the calculations for the resource Flexibility Benefits. The difference in costs between the test cases and the base case provides the flexibility benefit of the test case resource. The full Flexibility Analysis (FA) methodology and results can be found in Chapter 5 and a description of the model can be found in Appendix G.

2025 FLEX VIOLATIONS. This workbook contains PLEXOS output data detailing the flexibility violations from the Flexibility Analysis model. All data was sourced from the 2025 Flexibility Analysis model. The full Flexibility Analysis (FA) methodology and results can be found in Chapter 5 and a description of the model can be found in Appendix G.

I

Natural Gas Analysis Results

This appendix presents details of the methods and model employed in PSE's natural gas resource analysis and the data produced by that analysis.

Contents

1. NATURAL GAS PORTFOLIO MODEL

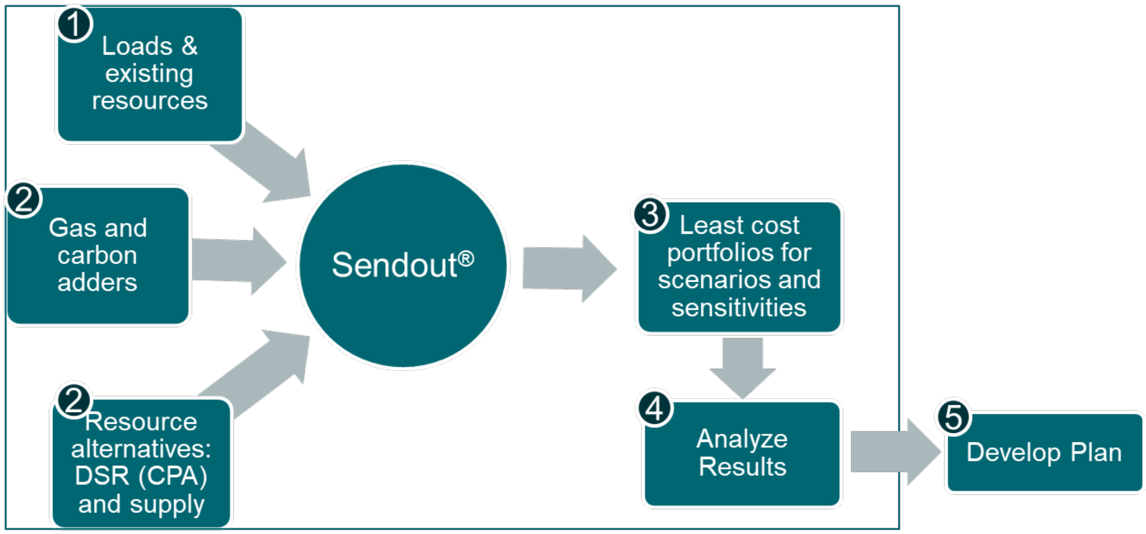
To model gas resources and alternatives for both long-term planning and natural gas resource acquisition activities, PSE uses a gas portfolio model (GPM). The GPM used in this IRP is SENDOUT® from ABB, a widely used software tool that helps identify the long-term least-cost combination of resources to meet stated loads. Other regional utilities that provide natural gas services, such as Avista, Cascade Natural Gas and FortisBC use the SENDOUT model. SENDOUT Version 14.3.0 was used for this analysis.

SENDOUT

SENDOUT is an integrated tool set for natural gas resource analysis that models the natural gas supply network and the portfolio of supply, storage, transportation and demand-side resources (DSR) needed to meet demand requirements. Figure I-1 shows how SENDOUT is used for natural gas resource analysis. Loads, existing resources, emission adders and resource alternatives are included as inputs into the SENDOUT model, which produces a least-cost portfolio based on those inputs.

SENDOUT can operate in two modes: For a defined planning period, it can determine the optimal set of resources to minimize costs; or, for a defined portfolio, it can determine the least-cost dispatch to meet demand requirements for that portfolio. SENDOUT solves both problems using a linear program (LP) to determine how a portfolio of resources (energy efficiency, supply, storage and transport), including associated costs and contractual or physical constraints, should be added and dispatched to meet demand in a least-cost fashion. The linear program considers thousands of variables and evaluates tens of thousands of possible solutions in order to generate a solution. A standard planning-period dispatch considers the capacity level of all resources as given, and therefore performs a variable-cost dispatch. A resource-mix dispatch can look at a range of potential capacity and size resources, including their fixed and variable costs.

Figure I-1: SENDOUT Inputs and Outputs in the 2021 PSE IRP



PSE's gas portfolio model analysis follows a six-step process.

1. Set up database with existing resources and demand forecast.
2. Update inputs for natural gas prices, carbon adders and new resource alternatives.
3. Perform long-run capacity expansion analysis to get least cost portfolio for each scenario and sensitivity.
4. Analyze results.
5. Develop resource plan.

SENDOUT Model Inputs

NATURAL GAS PRICES. For natural gas prices, PSE uses a combination of forward market prices and fundamental forecasts acquired in Spring 2020 from Wood Mackenzie. The natural gas price forecast is an input into the SENDOUT; the natural gas price inputs as described in Chapter 5.

CO_2 PRICE INPUTS. RCW 80.28.380 requires that the natural gas analysis include the cost of greenhouse gases when evaluating the cost-effectiveness of natural gas conservation targets. To implement this requirement, the SCGHG is added to the natural gas commodity price. Detailed inputs are provided in Chapter 5.

DEMAND-SIDE RESOURCES. SENDOUT provides a comprehensive set of inputs to model a variety of energy efficiency programs. Costs can be modeled at an overall program level or broken down into a variety of detailed accounts. The impact of demand-side resources on load can be modeled at the same level of detail as demand. SENDOUT has the ability to integrate demand- and supply-side resources in the long-run resource mix analysis to determine the most cost-effective size of demand-side resources.

NATURAL GAS SUPPLY. SENDOUT allows a system to be supplied by either long-term natural gas contracts or short-term spot market purchases. Specific physical and contractual constraints can be modeled on a daily, monthly, seasonal or annual basis, such as maximum flow levels and minimum flow percentages. SENDOUT uses standard gas contract costs; the rates may be changed on a monthly or daily basis.

STORAGE. SENDOUT allows storage sources (either leased or company-owned) to serve the system. Storage input data include the minimum or maximum inventory levels, minimum or maximum injection and withdrawal rates, injection and withdrawal fuel loss to and from interconnects, and the period of activity (i.e., when the gas is available for injection or withdrawal). There is also the option to define and name volume-dependent injection and withdrawal percentage tables (ratchets), which can be applied to one or more storage sources.

TRANSPORTATION. SENDOUT provides the means to model transportation segments to define flows, costs and fuel loss. Flow values include minimum and maximum daily quantities available for sale to gas markets or for release. Costs include standard fixed and variable transportation rates, as well as a per-unit cost generated for released capacity. Seasonal transportation contracts can also be modeled.

DEMAND. SENDOUT allows the user to define multiple demand areas, and it can compute a demand forecast by class based on weather. The demand input is segregated into two components: 1) base load, which is not weather dependent, and 2) heat load, which is weather dependent. Both factors are further computed as a function of customer counts. The heat load factor is estimated by dividing the remaining non-base portion of the load by historical monthly average heating degree days (HDD) and monthly forecasted customer counts to derive energy per HDD per customer. The demand is input into SENDOUT on a monthly basis and includes the customer forecast, the baseload factors and the heat load factors computed over the entire 20-year demand forecast period. More information on the natural gas demand forecast can be found in Chapter 6.

The gas analysis uses a design day peak standard of 52 HDD.[1] This design peak day demand value is manually inserted into the historical peak month, which is December for this 2021 IRP. More information on the design peak day can be found in Chapter 9, Natural Gas Analysis.

Resource Alternatives Assumptions

Figure I-2 summarizes resource costs and modeling assumptions for the pipeline alternatives considered in the 2021 IRP, and Figure I-3 summarizes resource costs and modeling assumptions for storage alternatives.

1 / The design day peak standard of 52 Heating Degree Days was established in PSE's 2005 IRP, Appendix I, Gas Planning Standard.

Figure I-2: Prospective Pipeline Alternatives Available

Alternative	From/To	Capacity Demand ($/Dth/Day)	Variable Commodity ($/Dth)	Fuel Use (%)	Earliest Available	Comments
Westcoast + NWP Expansions	Station 2 to PSE	0.52 + 0.56	0.05 + 0.09	1.6 + 1.5	Nov. 2025	Westcoast expansion coupled with NWP expansion
Short Term NWP TF-1	Sumas to PSE	0.38	0.09	1.5	Nov. 2021	Potentially available from PSE Power Book, possibly from 3rd parties
Fortis BC / Westcoast (KORP) + NWP Expansions	Kingsgate to PSE via Sumas	0.42 + 0.56	0.05 + 0.09	1.6 + 1.5	Nov. 2025	Prospective projects & estimated project cost - requires NGTL and Foothills
NGTL (Nova) Pipeline	AECO to Alberta / BC border	0.16	0	0	Nov. 2025	Prospective projects & estimated project cost - requires Foothills and GTN
Foothills Pipeline	Alberta / BC Border	0.12	0	1	Nov. 2025	Prospective projects & estimated project cost - requires NGTL and GTN
GTN Pipeline	Kingsgate to Stanfield	0.2	0.044	1.4	Nov. 2025	Prospective projects & estimated project cost - requires NGTL and Foothills.
NWP Columbia Gorge	Stanfield to PSE	0.8	0.005	2	Nov. 2025	Prospective project & estimated project cost - requires NGTL/Foothills/GTN.
Incremental NWP - Backhaul	I-5 to PSE	0.28	0.09	1.5	Nov. 2025	capacity resulting from NWP Sumas South Expansion; Demand Charge Winter Only rate requires Mist Storage
Long Term NWP TF-1	Plymouth to PSE	0.38	0.09	1.5	Apr. 2023	Maximum 15 MDth/d, available from 3rd parties effective Apr. 2023
Tacoma LNG Distribution Upgrade	Tacoma LNG to PSE	0.23	0	0	Nov. 2025	Upgrade of the distribution system to connect the LNG plant to additional area of the PSE system

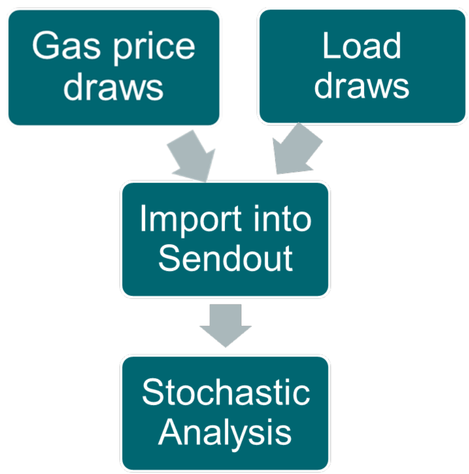
Figure I-3: Prospective Storage Alternatives Available

Alternative	Storage Capacity (MDth)	Maximum Withdrawal Capacity (MDth/day)	Days of Full Withdrawal (days)	Max. Injection Capacity (MDth/day)	Earliest Available	Comments
Mist Expansion	1,000	50	20	20	Nov. 2025	Prospective project, estimated size and costs, confidential - requires NWP backhaul capacity
Plymouth LNG	241.7	15	16	-	Apr. 2023	Existing plant - requires LT firm NWP capacity
Swarr	90	30	3	-	Nov. 2024	Existing plant requiring upgrades; on-system, no pipeline required

2. STOCHASTIC MODEL

For the stochastic analyses, the natural gas prices and load draws are varied in order to provide varied inputs for the SENDOUT model. Figure I-4 shows how SENDOUT is used for stochastic gas resource analysis.

Figure I-4: The Stochastic Natural Gas Analysis Process



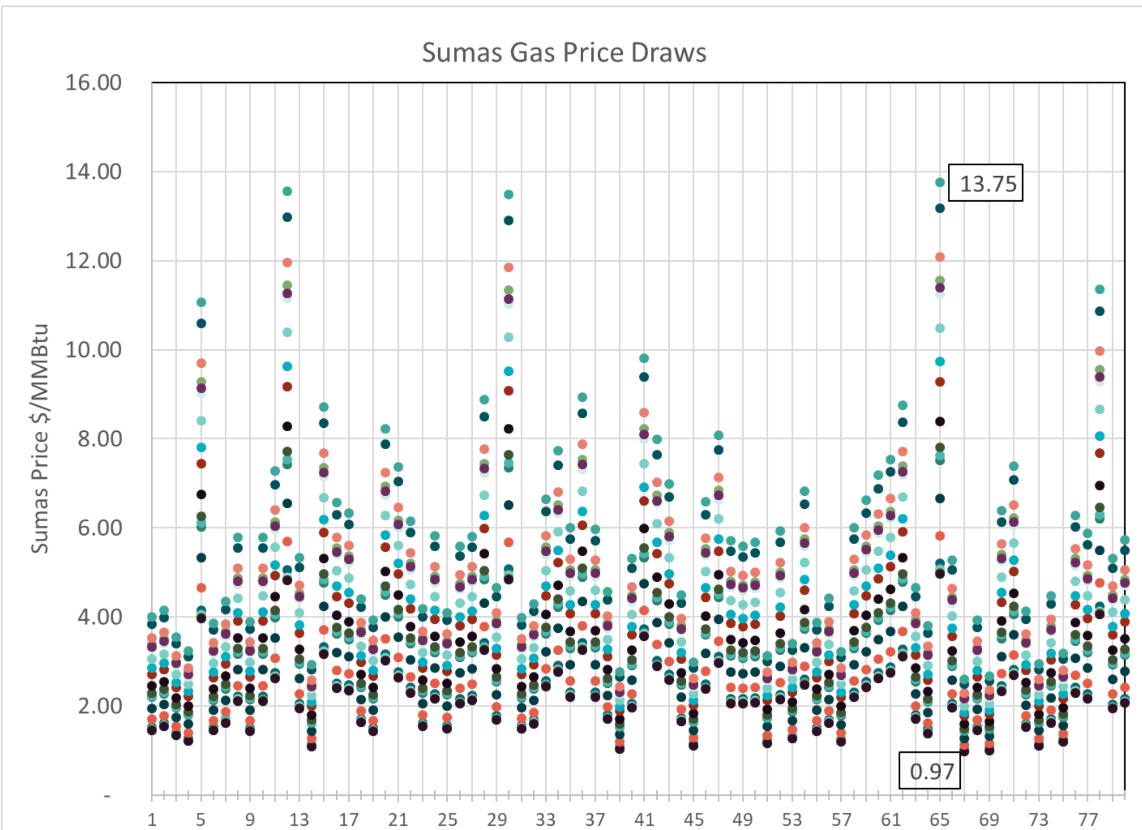
Stochastic Model Inputs

The development of natural gas price draws and demand draws is the starting point for the stochastic analysis. Eighty natural gas price draws were developed using the risk functionality tool in the electric AURORA model, mirroring the natural gas price and demand draws used in the electric analysis. For the demand draws, the 250 draws that the load forecasting group used to develop the Low and High Scenarios were used.

NATURAL GAS PRICE DRAWS. For the Sumas, AECO, Rockies and Stanfield natural gas hubs, the natural gas stochastic analysis used the same 80 natural gas price draws developed for the electric stochastic analysis.[2] Natural gas prices for Station 2 and Malin were generated in SENDOUT using the basis differential pricing off one of the four hubs. The 80 draws were also repeated to create 250 draws. For each hub, a total of 19,200 prices (80 draws x 12 months/year x 20 years), were repeated to obtain 60,000 natural gas prices for each hub.

Each natural gas price draw was then adjusted to include the SCGHG and upstream emission adders in SENDOUT. With the addition of SCGHG and upstream emissions, the expected natural gas price shifted from \$2.25/MMBtu to \$7.57/MMBtu in 2022.

Figure I-5: Natural Gas Price Draws for Sumas Hub

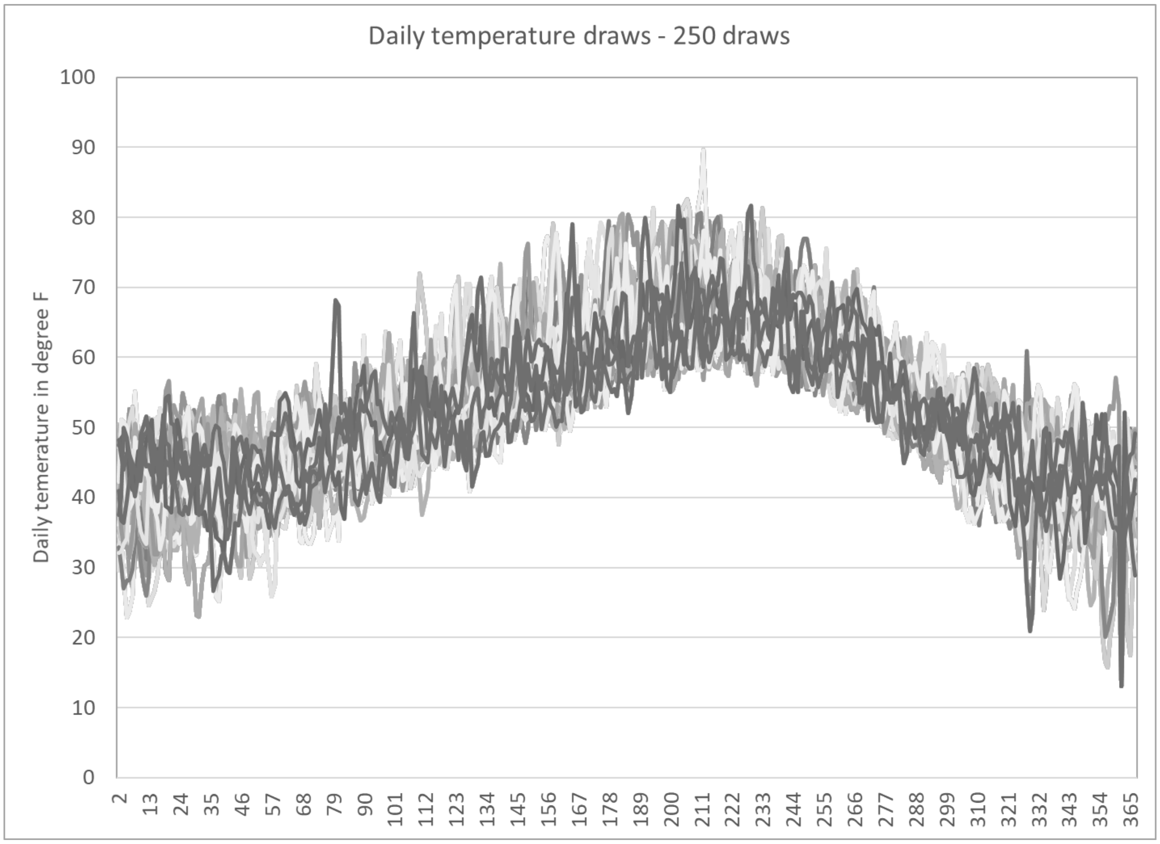


SCGHG AND UPSTREAM EMISSIONS. The deterministic SCGHG and upstream emissions costs were added to each natural gas price draw.

2 / The natural gas price draws were developed from the monthly forecasts that were used in the deterministic models, taking hub and lag correlations into account. See Appendix G, Electric Analysis Models, for a more detailed description of the methodology.

LOAD DRAWS. SENDOUT uses temperature draws to calculate demand. The 250 demand draws were developed from the "normal" weather data used in the Base Demand Forecast, defined as the average monthly weather recorded at NOAA's Sea-Tac Airport station over the past 30 years ending in 2019. Before the draws were imported into SENDOUT, they were adjusted to include the natural gas planning peak day temperature. Figure I-6 below shows the temperature draws.

Figure I-6: Daily Temperature Draws



Stochastic Analysis

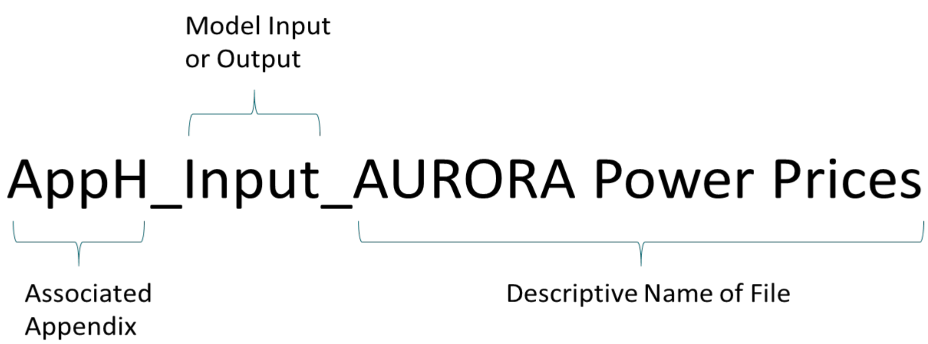
In order to test the portfolios developed in the deterministic scenario analysis under a wider range of demand and natural gas prices, PSE ran the portfolio two different ways

1. **Resource/Cost Optimization**: This analysis tests the portfolio against 250 variations (draws) of different demand and natural gas price combinations. The model was allowed to change the resource additions to optimize portfolio cost for the different demand and price conditions. This results in a different portfolio for each draw.
2. **Mid Fixed Portfolio:** This analysis tests the robustness of a deterministic portfolio. The resource portfolio is fixed and then run through the 250 demand and natural gas price combinations to evaluate the portfolio's cost and reliability risks. This analysis tests the robustness and risks around a single portfolio.

3. APPENDIX I DATA FILES

For the 2021 IRP, PSE is providing Microsoft Excel files containing input and output data in separate files instead of presenting static data tables. The direct access to the data provides usable files for stakeholders as opposed to static tables in a PDF format. Technical limitations on how PSE is able to submit files to the WUTC and host files online for stakeholder access has prevented PSE from keeping the files organized in a series of folders. To overcome this, a descriptive naming system has been developed in order to identify different files. Figure I-7 provides an example of how the files will be named in Appendix H, Electric Analysis Inputs and Results. The same format is used for files from Appendix I. Each Excel file also contains a "Read Me" sheet with specific details related to the data contained in that file.

Figure I-7: Naming Conventions for Appendix H and Appendix I Data Files



The Appendix I files contain the energy savings, costs and peak contributions of the DSR data in the Mid Scenario and the natural gas DSR sensitivities. The values include DSR values for both firm and interruptible programs. Values that are broken down by sector (Industrial, Commercial, and Residential) are recombined before being used in any model. The addition of these breakdowns were provided by Cadmus and are included in the files, but were not used separately in the 2021 IRP. Figure I-8 provides the file names of these datasets, and more information about DSR data can be found in Appendix E, Conservation Potential Assessment and Demand Response Assessment.

Figure I-8: Appendix I File Names

File Names	Description
Appl_Input_Gas DSR Base	Contains the normal bundles, as well as codes and standards (C&S), combined heat and power (CHP), and Solar DSR outputs.
Appl_Input_Gas DSR 6Yr	Applies a 6-year ramp rate to conservation measures implemented in the DSR dataset instead of 10 years.
Appl_Input_Gas DSR NEI	Includes additional non-energy impacts in the energy savings of the bundles.
Appl_Input_Gas DSR SDR	Applies a 2.5% discount rate to the conservation measures.
Appl_Output_SENDOUT	This file contains a high-level overview of SENDOUT results. The Mid, Low, and High Scenarios, as well as the 6-Year Ramp, Social Discount Rate, and Non-energy Impact sensitivities on conservation values.

J Regional Transmission Resources

This appendix describes the Pacific Northwest transmission system and the constraints that currently impact PSE; the opportunities for expanding transmission capabilities; how transmission is modeled in this IRP; and regional efforts to coordinate transmission planning and investment.

Contents

1. OVERVIEW

PSE buys and sells wholesale power and transmission with counterparties in the Pacific Northwest, California and Canada. To deliver remote, off-system power to our customers, PSE relies on the Pacific Northwest regional transmission system; however, that system is already constrained, especially the regional systems that serve the Puget Sound area.

These constraints present a growing challenge for PSE, because PSE moves significant amounts of energy and capacity into the Puget Sound area from resources in eastern Washington (east of the Cascades), the Mid-C trading hub, eastern Montana, and from resources along the I-5 corridor. The IRP portfolio modeling results confirm that PSE's capacity and resource needs due to CETA will dramatically increase PSE's need to cost effectively deliver off-system renewable resources to our service territory, and this rapid growth in renewable resources in locations outside the PSE service territory will put increased demand on transmission providers in the region.

PSE will work to optimize use of its existing transmission portfolio to meet our growing need for renewable resources in the near term, but in the long term, meeting CETA requirements will mean that the Pacific Northwest transmission system will need significant expansion and upgrades to keep pace. The main areas of high-potential renewable development are east of the Cascades (Washington and Oregon), in the Rocky Mountains (Montana, Wyoming), in the desert southwest (Nevada, Arizona) and in California.

This appendix describes the Pacific Northwest transmission system and the constraints that currently impact PSE; the opportunities for expanding transmission capabilities; how transmission is modeled in this IRP; and regional efforts to coordinate transmission planning and investment.

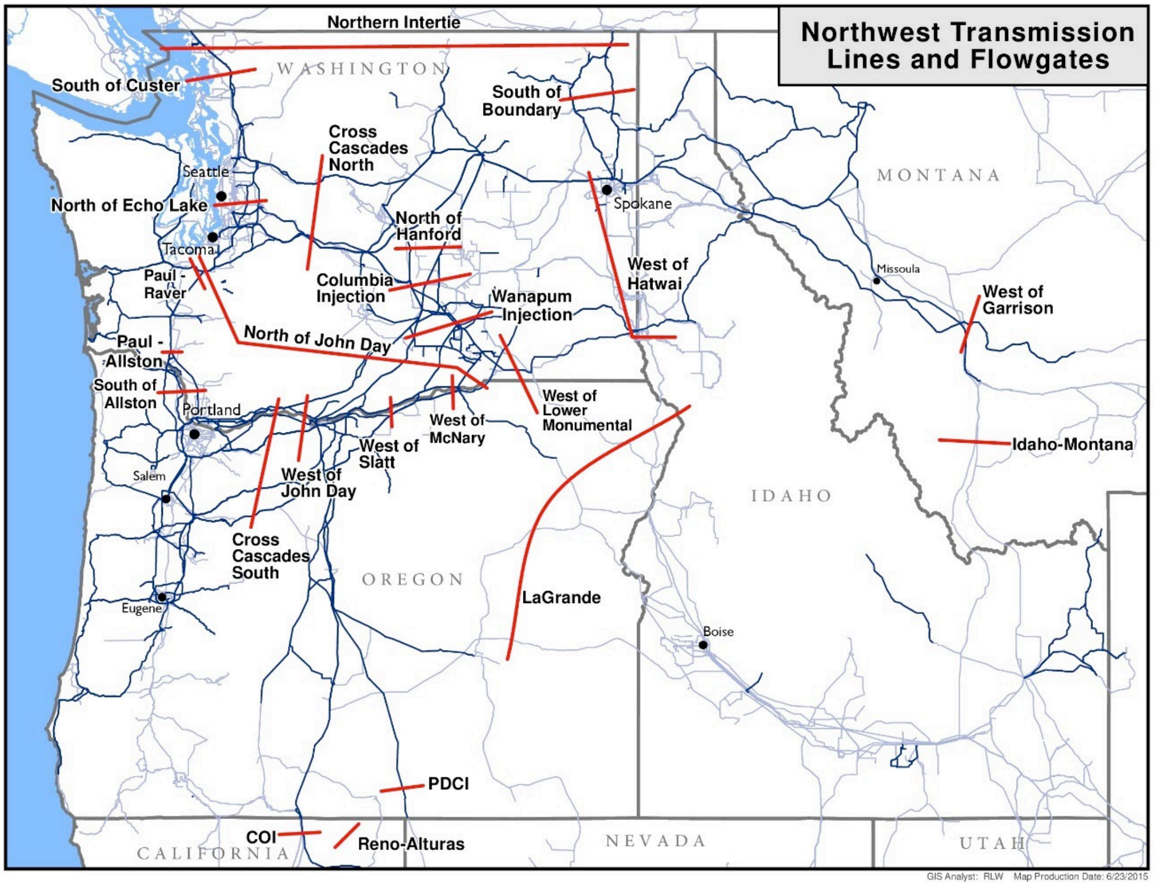
2. THE PACIFIC NORTHWEST TRANSMISSION SYSTEM

The power that PSE delivers to customers from remote, off-system resources travels through the Pacific Northwest transmission system in order to reach the Puget Sound area. The Bonneville Power Administration (BPA) owns and operates approximately 75 percent of the high-voltage transmission grid across eight states in the region. PSE is heavily reliant on BPA; currently, PSE has over 5,000 MW of long-term firm transmission under contract with BPA. This reliance is an ongoing risk to PSE's power costs due to escalating BPA rate pressure. For example, BPA's current BP-22 rate case proposes a 30 percent increase in transmission rates from 2021-2025: for 2022, the proposed rate increase is 11 percent.

Power travels to PSE's service area through different paths and flowgates[1] on the BPA system from off-system resources. These flowgates are shown in Figure J-1. Due to load growth and/or additional renewable generation, many paths in the Pacific Northwest are already constrained, with little or no Available Transmission Capacity (ATC) available for purchase by regional transmission customers. As a result, the region experiences transmission constraints during various times of the year, sometimes resulting in curtailments of firm contractual transmission rights.

1 / A flowgate is defined as a transmission line or other equipment that is monitored for overloads incurred by normal operation conditions, such as congestion, and for the loss of another transmission line or equipment.

Figure J -1: Graphical Representation of BPA Transmission System Flowgates



The PSE Transmission Portfolio

PSE Merchant (PSEM) is responsible for obtaining the transmission service needed to serve PSE load and for scheduling the use of that transmission in an optimal manner to cost effectively meet customer demand. The transmission portfolio is managed to ensure firm delivery of off-system resources, participate in regional energy markets, optimize the energy portfolio, and ensure adequate delivery of energy during winter peak loads.

Figure J-2 summarizes PSE's BPA-contracted transmission. The transmission rights are divided into five resource group regions based on their geographic relationship to generic resources modeled in this IRP. See Chapter 5, Key Analytical Assumptions, for a description of the transmission constraints analysis.

Figure J-2: Summary of BPA-contracted Transmission by Resource and Location

Resource/Location	Resource Group Region (See Chapter 5)	Current Contracted BPA Transmission (MW)	Notes
Mid-C	Central WA	2,050 MW	1,500 MW available for market purchases, remainder for hydro contracts
Lower Snake River	Eastern WA	500 MW	350 MW in use, 150 MW available in 2024
Hopkins Ridge	Eastern WA	150 MW	Not included in transmission constraint model in Chapter 5
Goldendale	Southern WA/ Gorge	330 MW	
Mint Farm	Western WA	335 MW	
TransAlta/Centralia	Western WA	100 MW	Used for Centralia PPA ending in 2026
Colstrip	Montana	750 MW	
PG&E Exchange	Western WA	600 MW	300 MW bi-directional, not included in transmission constraint model in Chapter 5

PSEM's transmission portfolio consists of transmission rights on PSE's system and BPA transmission for off-system resources. PSEM holds BPA transmission rights from the Mid-C trading hub for meeting winter peak demands and for trading to economically optimize the power portfolio. In addition, PSEM has transmission rights on the Southern Intertie, California/Oregon Intertie (COI), Montana Intertie, and the Colstrip Transmission System. The Southern Intertie and COI transmission rights are used for a seasonal exchange with PG&E. PSEM also uses contracted BPA transmission rights to access the Western Energy Imbalance Market (EIM) through transmission paths with PacifiCorp, Portland General and Idaho Power.

Figure J-3: BPA-managed Flowgates and PSE Off-system Resources

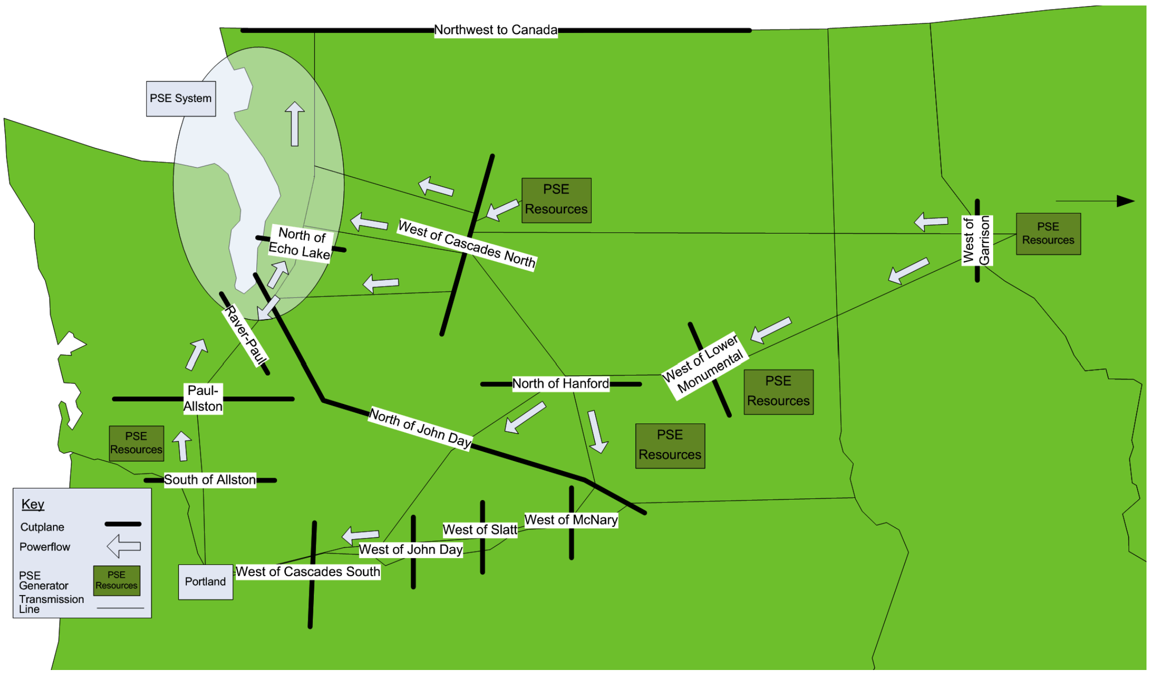


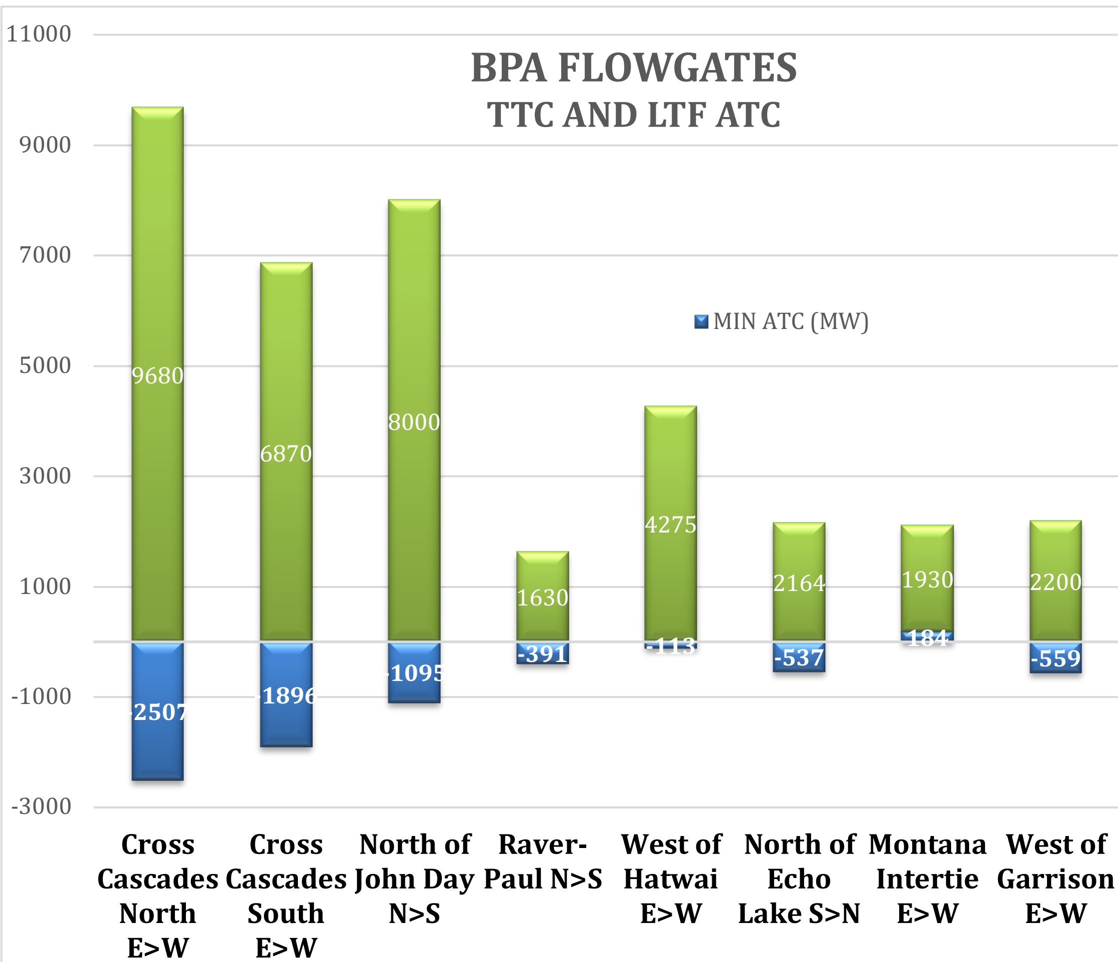
Figure J-3 is an overview of PSEM's off-system resources overlaid with the BPA-managed flowgates. Below is a summary of the most significant flowgates and paths affecting delivery of energy from remote resources to PSE's service area.

a. The majority of energy from PSE's eastern Washington resources flows across the constrained West of Cascades North flowgate and into the Puget Sound area. This flowgate is most constrained during heavy winter loading periods.
b. A portion of the energy flowing from eastern Washington resources also flows over the West of Cascades South flowgate, and as it travels to loads in the Puget Sound area, it flows over the North of John Day and Raver – Paul flowgates. The West of Cascades South flowgate is most constrained during heavy winter loading periods, while the North of John Day and Raver – Paul flowgates are typically most constrained during heavy summer loading periods.
c. Energy from PSE resources in Montana flow over the West of Garrison flowgate.
d. Congestion issues in the Puget Sound area are monitored by the North of Echo Lake flowgate and the Northern Intertie. Generation from PSE resources located in Skagit and Whatcom Counties is particularly important in reducing curtailment risk on the North of Echo Lake flowgate.
e. Energy from PSE's Lower Snake River Wind Project flows across the West of Lower Monumental flowgate.

Some paths, like West of Garrison, are designed to operate close to their limits, others are not; the latter group presents areas of the system where PSE sees a particular importance in continuing to study, develop and possibly construct new transmission.

Figure J-4 lists the amount of total transmission capability and Available Transmission Capability on BPA flowgates that affect delivery of off-system resources to PSE. This table highlights a constrained regional transmission, especially on transmission lines that would deliver energy from outside the Puget Sound area.

Figure J-4: BPA Flowgates Affecting Delivery of Off-system Resources to PSE's System Total Transmission Capability and Long-term Firm Available Transmission Capability



3. OPPORTUNITIES FOR EXPANDING REGIONAL TRANSMISSION CAPABILITY

BPA TSR Study and Expansion Process (TSEP)

BPA performs annual TSEP (formerly known as Network Open Season [NOS]) studies that combine various Transmission Service Requests (TSRs) from transmission customers into a single study. The TSEP process was designed to obtain financial commitments from transmission customers in advance of any new facility construction. For long-term transmission requests, the process analyzes impacts and new transmission facility requirements on an aggregated basis. Customers that submit a TSR in OASIS (Open Access Same-time Information System) by the study deadline can elect to be included in the annual TSEP cluster study.

A TSR submitted to BPA by PSE could result in TSEP study results with costly upgrades and completion dates of 10 years or longer. For example, the cost of Montana-to-Washington upgrade projects identified in the 2020 TSEP study (in response to requests from other customers) is currently estimated at $1.4 billion, and the earliest completion date is 2030. PSE is likely to see more high-cost and long lead-time proposals in the constrained areas of BPA's system, especially in cross Cascades transmission areas. There is no commitment risk for PSE to submit TSRs in constrained areas of BPA's system since contracts are not awarded until construction is under way, but we would want such a strategy to align with areas that have high potential for renewables development.

2019 TSEP Study

PSE participated in the 2019 TSEP study. The table below lists the outcomes of the study for PSE TSRs. PSE was awarded transmission for the Goldendale Generation Plant but the Hopkins Ridge TSR resulted in a need to either resolve local transmission constraints or an upgrade called the Walla Walla Project.

Figure J-5: Summary of 2019 TSEP Study Results for PSE TSRs[2]

Project	Start Date	End Date	MW	Status
Hopkins Ridge (Central Ferry Substation)	3/1/2024	1/1/2027	75	Walla Walla Project or resolution of local transmission constraints
Goldendale (2 TSRs)	11/1/2021	3/1/2024	27	Awarded

2020 TSEP Study

In May 2020, BPA published the results of the 2020 TSEP Cluster Study. The cluster study was comprised of 62 TSRs totaling 3,871 MW of incremental transmission service. PSE did not submit any TSRs that took part in the study. A total of 17 TSRs submitted by four BPA transmission customers listed PSE as a Point of Delivery (POD). The results of those 17 TSRs are listed in Figure J-6 along with the required upgrade projects. These results are indicative of the cost and timing of future upgrades for future TSRs of BPA transmission to PSE.

Figure J-6: Summary of 2020 TSEP Study Results for Third Parties with PSE PODs

PSE POD	First Start Date	Last End Date	Total MW Requested	Upgrade Required (Cost $M)	Energization Date
COVNGTN230PSEI	12/1/21	1/1/31	970	Schultz-Raver Project ($42.6)	Fall 2025
PSEI_CENTCNTGS	12/1/21	11/1/24	7	Schultz-Raver Project ($42.6) PSAST Projects	Fall 2025
PSEI_STHCNTGS	12/1/23	12/1/28	200	Schultz-Raver Project ($42.6) Schultz-Wautoma ($0) Covington-Chehalis ($12.6)	Fall 2025 Spring 2022 Fall 2024

2 / Refer to BPA's TSEP Page: https://www.bpa.gov/transmission/CustomerInvolvement/TSRStudyExpansionProcess/Pages/default.aspx

Future TSEP Studies

BPA announced that it will perform another TSEP in 2021 to identify transmission projects required to grant new Transmission Service Requests as part of its ongoing efforts to address constraints. The 2021 study will take into account the 2016, 2019 and 2020 TSEP cluster study results and prior NOS study results.

Montana Transmission

Wind resources in Montana are attractive because of their higher capacity factors and diverse seasonal output compared to the Washington wind currently in PSE's energy portfolio. The retirement of Colstrip Units 1 and 2 provided for an opportunity to evaluate Montana wind resources in PSE's 2018 RFP, allowing for the potential repurposing of Colstrip transmission to PSE's service territory. The impact of such repurposing on the available transfer capacity for PSE's portion of the Colstrip Transmission System is being studied by NorthWestern Energy, as well as by affected systems such as BPA.

Idaho and Wyoming Transmission

PSE is evaluating potential investment in transmission service on the Boardman to Hemingway (B2H) and Gateway West projects. These investments would provide access to Idaho and Wyoming renewable resources. Wyoming wind is particularly attractive because of its capacity factors and diverse wind profiles and is being evaluated as a potential resource in this IRP. In order to deliver resources from B2H to PSE load, PSE will also need to acquire BPA transmission from the Boardman location (newly proposed Longhorn Substation) to PSE's system. BPA will perform a study in 2021 to determine availability of that transmission service by 2026. We expect the results of that study later in 2021.

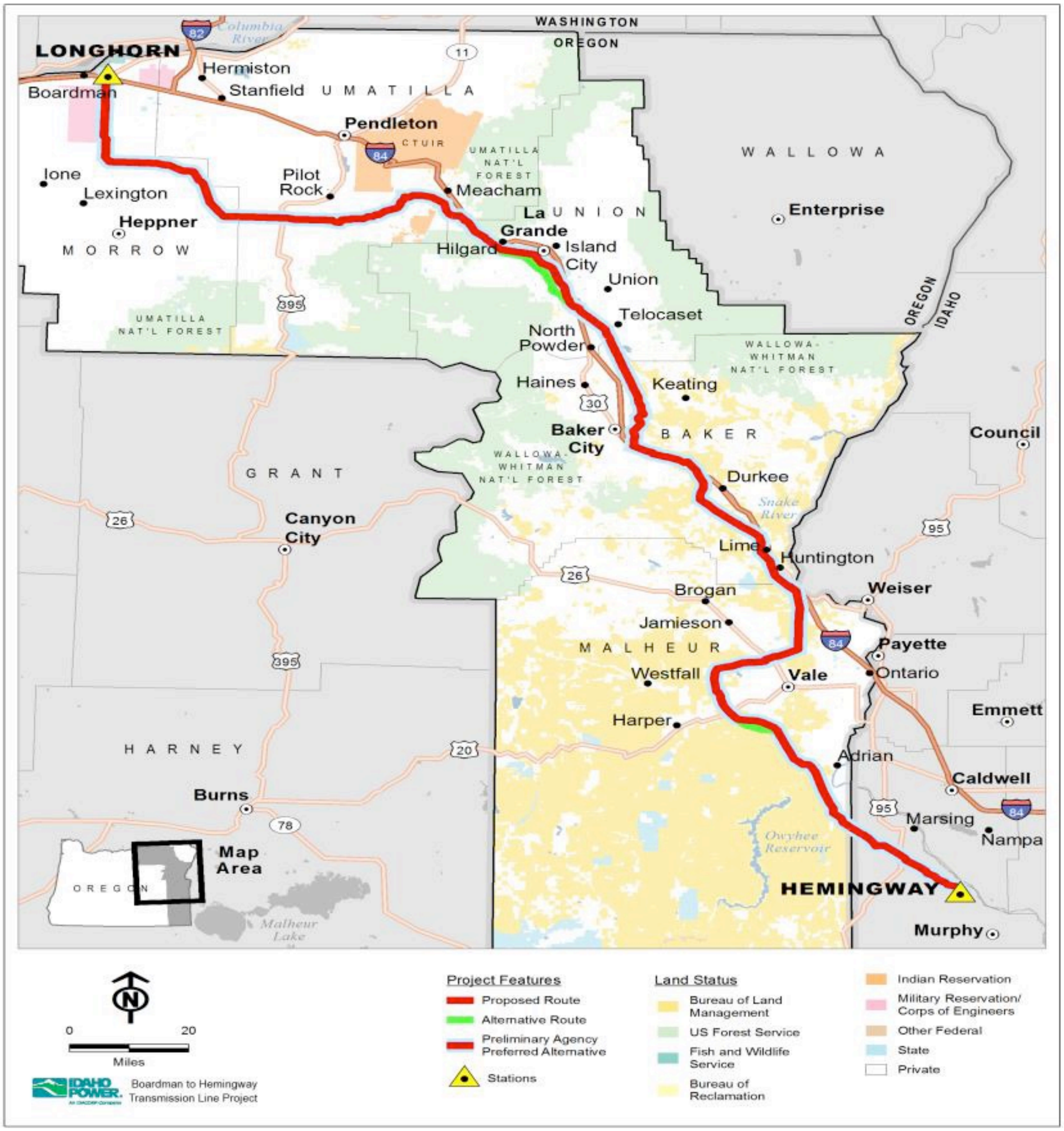
PSE is conducting a due diligence assessment of B2H and each Gateway West segment that includes an evaluation of project permitting, construction schedules, construction cost estimates and project risks. This assessment is planned to be completed during 2021 and will inform PSE's future decision. The following is a high-level summary of the B2H and Gateway West transmission projects.

Boardman to Hemingway (B2H)

PSE is evaluating an investment in 400 MW of currently available east to west capacity on the B2H project, with a potential for another 200 MW for a total of 600 MW of transmission. An investment in B2H, along with potential investments in one or more segments of Gateway West, would provide PSE access to high-value wind and solar resources in southern Idaho, western Wyoming and eastern Wyoming (see Figure J-7).

The B2H project is a proposed 500 kilovolt transmission line that will run approximately 290 miles across eastern Oregon and southwestern Idaho. It will connect the proposed Longhorn Substation four miles east of Boardman, Oregon, to Idaho Power's existing Hemingway Substation in Idaho. Idaho Power is partnering with PacifiCorp to fund and construct B2H and to obtain necessary permits for a planned 2026 or later in-service date. Construction is expected to take three to four years to complete.

Figure J-7: B2H Route Map



Gateway West

In addition to B2H, PSE is evaluating transmission investments in one or more segments of Gateway West, starting at the eastern Wyoming substation Aeolus (see Figure J-8) and terminating at the Hemingway Substation in southern Idaho. The completion date for two of the three segments is not yet determined. PacifiCorp is the primary transmission provider for Gateway West and is partnering with Idaho Power on portions of the southern Idaho segment. The three segments of Gateway West that PSE is evaluating are discussed below.

HEMINGWAY TO POPULUS. This western segment is located in southern Idaho. Along with B2H, it would provide PSE access to southern Idaho renewable resources including wind and solar projects. There is not yet a firm construction date for this segment.

POPULUS TO BRIDGER/ANTICLINE. This segment is located in southern Idaho and western Wyoming. Along with Hemingway to Populus, it would provide PSE access to western Wyoming wind and solar resources. Similar to the Hemingway to Populus segment, there is not yet a firm construction date for this segment.

BRIDGER/ANTICLINE TO AEOLUS. PacifiCorp completed construction of this line in 2020. The line runs from western Wyoming to eastern Wyoming, and it would provide PSE access to high-capacity wind resources in eastern Wyoming.

Figure J-8: Gateway West Route Map

4. FUTURE REGIONAL TRANSMISSION STRATEGIES

Transmission Strategies

Four strategies could be implemented to ensure sufficient transmission for the delivery of off-system renewable projects to PSE's system.

- **Strategy 1:** Repurpose the existing BPA transmission portfolio. Use Mid-C and Montana transmission for renewables, and co-locate new renewable resources at existing PSE generating facilities.
- **Strategy 2:** Connect resources directly to PSE system or acquire off-system renewables through a PSE transmission intertie.
- **Strategy 3:** Contract with BPA for additional transmission either directly or through third parties (developers, resellers).
- **Strategy 4:** Build new transmission.

Strategy 1

PSEM has approximately 1,500 MW of transmission at Mid-C which is currently used for market purchases. Some portion of Mid-C transmission could be used to take delivery of new renewable projects that interconnect at Mid-C or that deliver to Mid-C. The capacity credit for the transmission could be retained by having access to purchasing energy at the Mid-C market hub during winter peak events.

PSE has future transmission opportunities at several existing off-system generating facilities. A portion of PSE's Colstrip transmission could be repurposed for delivery of Montana wind and/or pumped hydro as the coal units retire. At the Lower Snake River wind plant, PSE has additional BPA interconnection and transmission rights to build new wind capacity. Renewable resources could also be co-located at the Goldendale and Mint Farm generating stations to share the BPA transmission rights from those locations.

Strategy 2

PSE has some available transmission on the main network and interties for delivery of energy from utility-scale projects or for contract with a third party for renewable PPAs.

Strategy 3

PSE could contract with BPA for additional transmission rights at candidate project locations for future resources by submitting TSRs and participating in BPA's annual cluster study. Additional BPA contracted transmission could also be secured through third parties such as renewable project developers and resellers of transmission. Due to current and anticipated regional transmission constraints, newly contracted BPA transmission service will likely require costly major upgrades and longer time lines to complete construction projects before new transmission service could commence.

Strategy 4

New regional transmission capacity will likely need to be constructed to meet the CETA requirements by 2045. As noted above, PSE is considering the Boardman to Hemingway and Gateway West transmission projects to access renewable resources in Idaho and/or Wyoming. In addition to those projects, PSE will assess existing rights of way for opportunities to access renewable energy zones in Washington state. PSE will also need to evaluate future greenfield transmission development with possible partners in the region. This will be an ongoing effort over the next several years since greenfield transmission projects can take 15 to 20 years to permit and put into service.

Future Transmission Considerations

Historically, PSE has required that any new resources secure long-term firm (LTF) transmission up to the nameplate rating of the generation. This policy was implemented to reduce the risk of being unable to deliver energy or produce RECs due to insufficient transmission. PSE is now considering acquisition of less than nameplate capacity of LTF transmission for renewable resources because the intermittent output of renewable resources usually leaves transmission idle, and there is often short-term transmission available (firm and non-firm) to purchase or redirect. This new policy could lower the future transmission need for renewable resources required to meet CETA and better optimize PSE's transmission portfolio.

This IRP includes a sensitivity analysis, Sensitivity E: Firm Transmission as a Percentage of Resource Nameplate, that tests the impact on portfolio cost when firm transmission is under-built for renewable resources. Sensitivity E analyzed the tradeoff between savings from avoided firm transmission contracts and costs from transmission-limited energy curtailment. Sensitivity E found that there is generally little benefit in under-building transmission for standalone wind and solar resources due to the amount of time these resources spend producing power near nameplate capacity. However, Sensitivity E did not include analysis of the impact of short-term firm and non-firm transmission, which may result in more favorable economics for variable energy resources and justify under-built transmission scenarios. Furthermore, Sensitivity E did show that co-located resources, such as wind and solar facilities which share the same interconnection, may benefit from under-built transmission due to complimentary generation shapes. The results of Sensitivity E are highly site-specific and further analysis must be completed on a case-by-case basis, but there is evidence that LTF transmission may not need to equal resource nameplate capacity into the future. For further detail on Sensitivity E, please see Chapter 5, Key Analytical Assumptions, and Chapter 8, Electric Analysis.

In May 2020, BPA began offering a new transmission product called long-term Conditional Firm Service (CFS). This is a form of Long-term Firm Point-to-point (LTF PTP) transmission service with either a limit on the number of hours per year that it can be curtailed or based upon system conditions. The CFS inventory is posted, and it presents another limitation with respect to some of the previously identified flowgates. The NOEL and West of Hatwai flowgates are showing zero Conditional Firm Inventory (CFI), but there is CFI along the Cross Cascades North flowgate. This flowgate is fully subscribed for the winter months of the year but typically has ATC during the remaining months. There is still some uncertainty about how effective this product will be with new renewable projects; PSE will evaluate CFS on a case-by-case basis when it is available from BPA. The cost for CFS is the same as LTF PTP.

In 2019, CAISO began to study the benefits of an Extended Day Ahead Market (EDAM) that would be available to its Energy Imbalance Market (EIM) participants and could be implemented as soon as 2022. This new market would allow EIM entities to participate in the current CAISO day ahead market. Initial studies have shown additional benefits of integrating a day ahead market construct on top of the EIM. Like the EIM, EDAM is being considered as a voluntary construct. In order to participate in EDAM, a utility would need to be a member of EIM. PSE is a member of the EIM and will continue to participate in the development of EDAM with other EIM entities and CAISO. One transmission-related aspect of the EDAM is to optimize transmission rights from participants and to make available unused/unsold transmission from transmission providers. As a result, the EDAM could help to optimize regional transmission and inform PSEM's future strategies on transmission acquisition.

5. REGIONAL TRANSMISSION PLANNING EFFORTS

PSE became a member of the newly formed NorthernGrid in 2020. As a Regional Planning Organization (RPO), NorthernGrid was formed as an association for the purpose of coordinating regional transmission planning for NorthernGrid members and facilitating compliance with certain FERC requirements relating to transmission planning (including Order Nos. 890 and 1000) for those members who are required (or may elect) to comply with such requirements. It is a successor organization to ColumbiaGrid, which formerly provided the same RPO services as NorthernGrid for PSE and other regional entities. NorthernGrid combines entities from ColumbiaGrid and the Northern Tier Transmission Group (NTTG).

FERC Orders 890 and 1000

PSE has long recognized the need for open, transparent and coordinated transmission planning and has consistently been ahead of regulation in its regional planning practices. The Federal Energy Regulatory Commission (FERC) has issued a series of orders, although two are regarded as seminal. These are Orders 890 and 1000, which have important and universal application to regulated transmission providers.

In the late 2000s, FERC recognized that "undue discrimination existed under the pro forma Open Access Transmission Tariff (OATT)."[3] The OATT had been in place since 1996, when it was mandated by FERC in Order 888.[4]

FERC Order 890, issued in February 2007, has three main goals: 1) strengthen the OATT to ensure that it achieves its original purposes of remedying undue discrimination; 2) provide greater specificity to reduce opportunities for undue discrimination and facilitate the Commission's enforcement; and 3) increase transparency in the rules applicable to planning and use of the transmission system.[5] FERC highlighted the six most critical types of reforms made in Order 890:

1. Increase nondiscriminatory access to the grid by eliminating the wide discretion that transmission providers currently have in calculating Available Transfer Capability (ATC).[6]

3 / FERC Order 890 ¶1
4 / Ibid
5 / Ibid
6 / Ibid at ¶2

2. Increase the ability of customers to access new generating resources and promote efficient utilization of transmission by requiring an open, transparent and coordinated transmission planning process.[7]
3. Increase the efficient utilization of transmission by eliminating artificial barriers to use of the grid.[8]
4. Facilitate the use of clean energy resources such as wind power.[9]
5. Strengthen compliance and enforcement efforts.[10]
6. Modify and improve several provisions of the OATT and clarify others that have proven ambiguous.[11]

The requirements of Order 890 are far-reaching and mandate changes and more open reporting in PSE's local and regional transmission planning, including the development of Attachment K with stakeholder participation.[12]

Issued in July 2011, FERC Order 1000 built upon the openness and transparency requirements of FERC Order 890 by requiring greater regional participation. Order 1000 includes provisions requiring transmission providers to:

- participate in a regional transmission planning process that evaluates transmission alternatives at the regional level that may resolve the transmission region's needs more efficiently and cost-effectively than alternatives identified by individual public utility transmission providers in their local transmission planning processes;[13]
- have in place a method, or set of methods, for allocating the costs of new transmission facilities selected in a regional transmission plan for purposes of cost allocation;[14] and
- amend their OATTs to describe procedures that provide for the consideration of transmission needs driven by Public Policy Requirements in the local and regional transmission planning processes.[15,16]

The requirements of FERC Order 1000 are designed to improve coordination across the regional planning processes by developing and implementing procedures for joint evaluation and the sharing of information between transmission providers and balancing authority areas. All regulated utilities are required to participate in a regional planning organization.

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7 / Ibid at ¶3.
8 / Ibid at ¶4
9 / Ibid.at ¶5
10 / Ibid.at ¶6
11 / Ibid at ¶7.
12 / Ibid at ¶437.
13 / FERC Order 1000 ¶6
14 / Ibid at ¶9
15 / Ibid at ¶203
16 / Public Policy Requirements are defined as transmission needs driven by public policy requirements established by state or federal laws or regulations. (FERC Order 1000 ¶2)

ColumbiaGrid and NorthernGrid

In 2006, before FERC had issued its mandates in Orders 890 and 1000, PSE became a founding member of ColumbiaGrid, a non-profit membership corporation and regional planning organization. ColumbiaGrid's goals were to improve the operational efficiency, reliability and planned expansion of the Pacific Northwest transmission grid. ColumbiaGrid provided a number of services, including annual transmission system assessments, producing a regional biennial transmission plan and identifying transmission needs. ColumbiaGrid also facilitated a coordinated planning process for the development of multi-party transmission system projects. Members included PSE, Avista, BPA, Chelan County Public Utilities District (PUD), Grant County PUD, Seattle City Light, Snohomish PUD and Tacoma Power.

Efforts started several years ago to form a single, larger regional planning organization in the Pacific Northwest that combined ColumbiaGrid members with members of NTTG. NTTG was a group of transmission providers and customers who were actively involved in the sale and purchase of transmission capacity that delivered electricity to customers in the Northwest and Mountain states. The new entity was named NorthernGrid, combining the names of the two groups. NTTG members joining NorthernGrid included Idaho Power, MATL, NorthWestern Energy, Portland General Electric and PacifiCorp.

On August 20, 2019, PSE and six other FERC-regulated utilities[17] filed the Funding Agreement and individual concurrences forming NorthernGrid in FERC docket ER19-2650-000. The NorthernGrid Funding Agreement also includes non-jurisdictional utilities, including BPA.[18] As explained in the opening of this section, NorthernGrid is an unincorporated association formed for the purpose of coordinating regional transmission planning for NorthernGrid members and facilitating compliance with certain FERC requirements relating to transmission planning (including Order Nos. 890 and 1000) for those members who are required (or may elect) to comply with such requirements.[19] In the Funding Agreement, member utilities requested an effective date of October 31, 2019, continuing until December 31, 2021, when the agreement will need to be renewed. FERC approved the Funding Agreement in a Delegated Order on October 28, 2019.

PSE, along with other regulated NorthernGrid entities, submitted its revised Attachment K under NorthernGrid to FERC on September 6, 2019, with a requested effective date of January 1, 2020 in FERC docket ER19-2760-000. On December 27, 2019 FERC issued an Order rejecting the proposed Attachment K tariff changes relating to Regional Planning, Cost Allocation and

17 / NorthWestern Energy, Avista, Idaho Power, MATL (Montana-Alberta Tie-Line), PacifiCorp, Portland General Electric
18 / Non-Jurisdictional entities, such as BPA, participate by choice in these regional planning organizations.
19 / NorthernGrid Funding Letter, Recital Number One.

Transmission needs driven by Public Policy Requirements. FERC did not find issue with PSE's revised Local Plan in Attachment K. PSE, and the other regulated NorthernGrid entities, submitted an updated Attachment K filing on January 29, 2020 in FERC docket ER20-882-000 requesting an effective date of April 1, 2020. FERC approved the revised Attachment K tariff filing on March 31, 2020, approving the April 1, 2020 effective date.

For the 2020 calendar year, PSE retained its Attachment K through ColumbiaGrid until April 1, 2020 and switched its planning tariff to the NorthernGrid Attachment K on April 1, 2020. ColumbiaGrid unwound its corporate status and dissolved prior to the end of 2020.

Participation in a regional planning organization like ColumbiaGrid or NorthernGrid, while mandated by FERC, also gives utilities an opportunity to develop a coordinated regional plan and allocate costs for transmission improvement projects that cross over more than one utility. The coordinated efforts can provide solutions on a larger scale than local planning efforts if more than one member is experiencing the same constraint issue. It also provides outside stakeholders another opportunity to share project suggestions and designs for consideration in regional planning. Given PSE's location in western Washington and the number of non-jurisdictional utilities in the Pacific Northwest, participation in a regional planning organization has been valuable, especially as these non-jurisdictional entities otherwise would not participate in a regional market.

K

Economic, Health and Environmental Benefits Assessment of Current Conditions

This appendix describes the methodology, initial assumptions and results for the Economic Health and Environmental Benefits Assessment per WAC 480-100-620 (9).

Contents

1. OVERVIEW

The Clean Energy Transformation Act (CETA) requires utility resource plans to ensure that all customers benefit from the transition to clean energy. To achieve this goal, an Economic, Health and Environmental Benefits Assessment must be performed to provide guidance to the development of the utility's Clean Energy Action Plan (CEAP)[1] and Clean Energy Implementation Plan (CEIP).[2] The purpose of the assessment is to identify and quantify the existing conditions for all customers and to identify disparate impacts to communities within and around PSE's service territory that are related to resource planning. The goal is for the utility to propose actions and programs that are not simply lowest reasonable cost, but also distribute its benefits equitably among customers.

This appendix explains the methodology used to create PSE's assessment, the data sources used to define certain customer groups, the metrics used to measure current conditions and PSE's first attempt to define and apply customer benefit indicators. The current methodology is informed by PSE's understanding of the Washington Utility and Transportation Commission (WUTC) rules issued in December 2020; however, this first attempt to incorporate the new rules is preliminary and lacks significant stakeholder feedback and iteration. PSE expects the analysis to evolve during development of the CEIP and future IRPs based on stakeholder feedback from both public participation and the Equity Advisory Group, as well as insights gained through experience and observation of industry best practice.

Strategy

To evaluate the equitable distribution of benefits, the assessment considers the following as defined in WAC 480-100-620 (9):

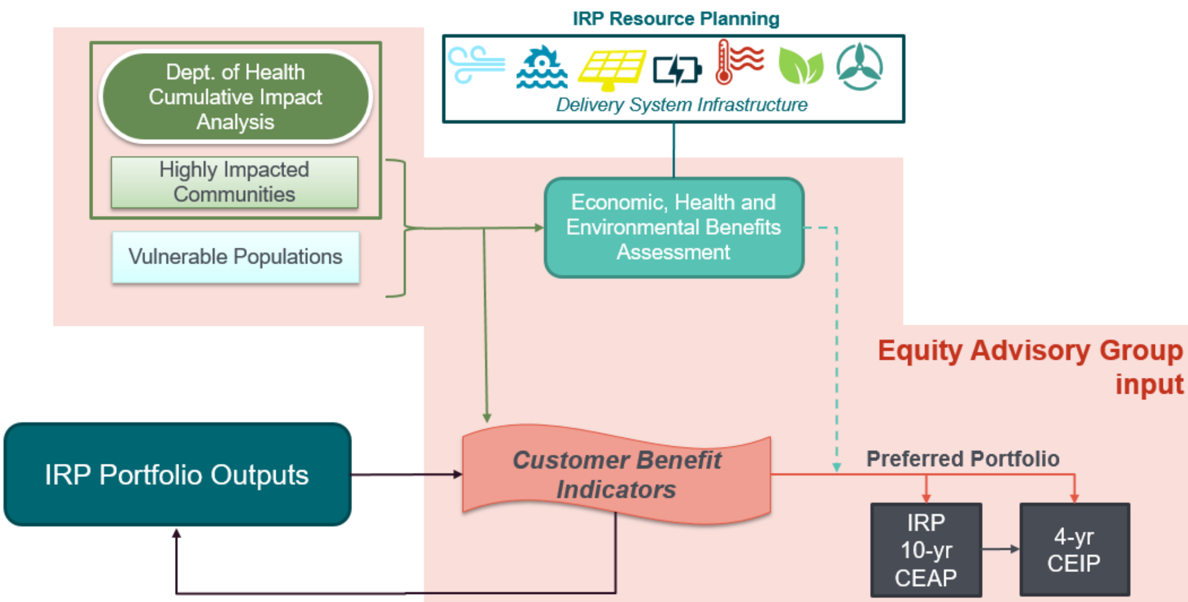
- energy and non-energy benefits and reductions of burdens to vulnerable populations and highly impacted communities
- long-term and short-term public health and environmental benefits, costs and risks, and
- energy security risk.

1 / The Clean Energy Action Plan is a 10-year outlook that achieves the clean energy transformation standards.
2 / The Clean Energy Implementation Plan identifies specific targets and actions PSE will take toward meeting the energy transformation standards.

Process Flows

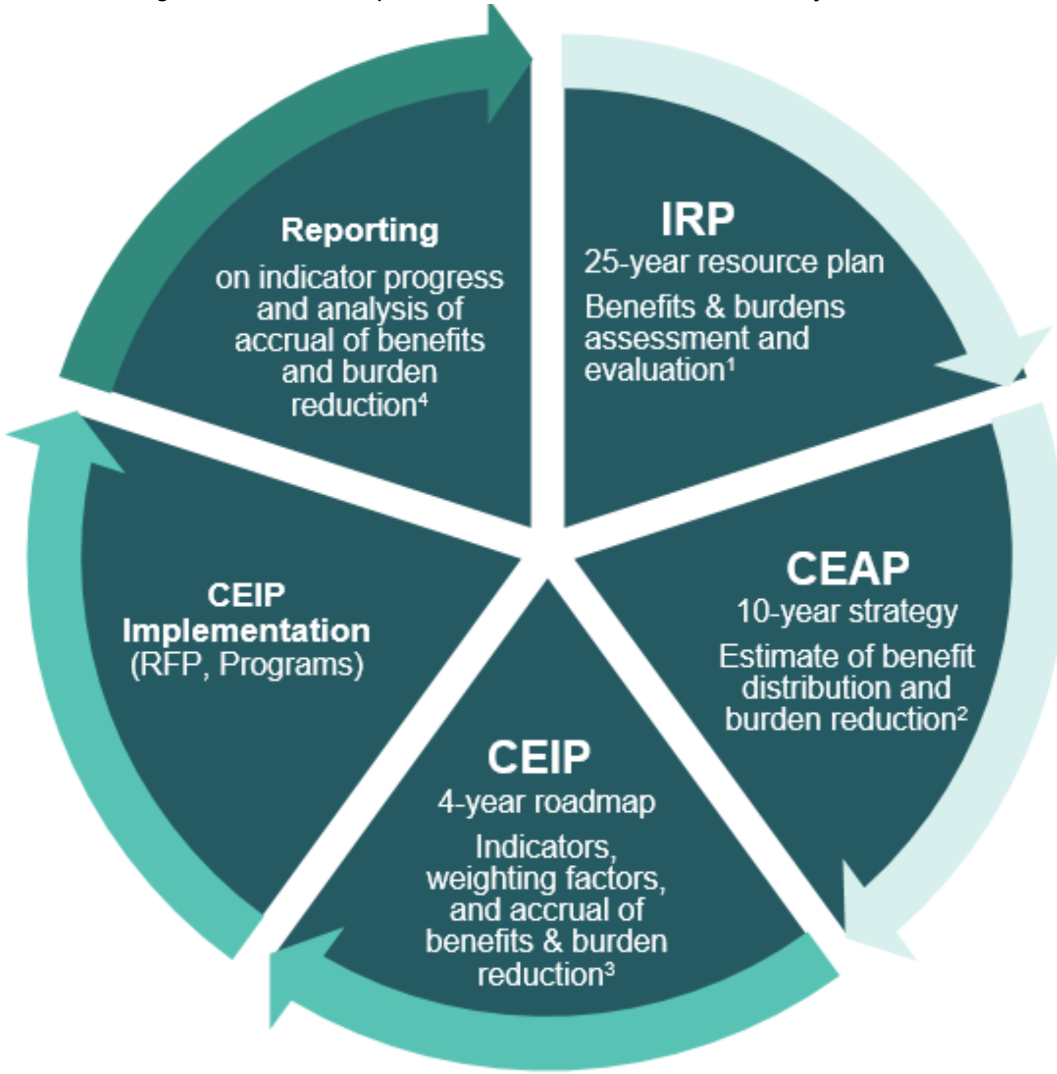
The Economic, Health and Environmental Benefits (EHEB) Assessment (or "the Assessment") fits into a much broader framework of planning for the equitable distribution of burdens and benefits in the transition to a clean energy future. Figure K-1 shows the where the EHEB Assessment fits in the context of the IRP, Clean Energy Action Plan and Clean Energy Implementation Plan. Information generally flows from broader, longer term analysis (the IRP) toward more specific, actionable analysis (the CEIP) and public input is solicited throughout.

Figure K-1: Equitable Distribution of Burdens and Benefits in the Planning Process



Learning and evolving from cycle to cycle is important to this process. The simplified process flow shown in Figure K-2 highlights the iterative nature of the process. Results from the CEIP will in turn help define inputs and improvements for future EHEB Assessments.

Figure K-2: CETA Equitable Distribution of Benefits Life Cycle



NOTES
1. IRP Assessment and Evaluation: Draft WAC 480-100-620(9) and (11)(g)
2. CEAP Estimates: Draft WAC 480-100-620(12)(c)(ii)
3. CEIP Indicators and Weighting Factors: Draft WAC 480-100-640(4) and (5)(a)
4. Reporting on indicator progress: Draft WAC 480-100-650(1)(d)

Definitions

Definitions are key to this assessment, and PSE anticipates the following definitions may change over time as a result of stakeholder feedback and the Department of Health's cumulative impact analysis.

ENERGY BURDEN. The share of annual household income used to pay annual home energy bills.

EQUITABLE DISTRIBUTION. A fair and just, but not necessarily equal, allocation of benefits and burdens from the utility's transition to clean energy. Equitable distribution is based on disparities in current conditions. Current conditions are informed by, among other things, the assessment described in RCW 19.280.030(1)(k) from the most recent integrated resource plan.

HIGHLY IMPACTED COMMUNITIES. A community designated by the Department of Health based on the cumulative impact analysis required by RCW 19.405.140 or a community located in census tracts that are fully or partially on "Indian country," as defined in 18 U.S.C. Sec. 1151.

VULNERABLE POPULATIONS. Communities that experience a disproportionate cumulative risk from environmental burdens due to: Adverse socioeconomic factors including unemployment, high housing and transportation costs relative to income, access to food and health care, linguistic isolation, and sensitivity factors such as low birth weight and higher rates of hospitalization.

PORTFOLIO OUTPUT. A unique measured value that is the result of a particular portfolio or sensitivity analyzed in AURORA based on the portfolio characteristics. These outputs are used to capture the customer benefit indicators.

CUSTOMER BENEFIT INDICATOR. An attribute, either quantitative or qualitative, of resources or related distribution investments associated with customer benefits described in RCW 19.405.040(8).

OCCUPIED HOUSING UNIT. A U.S. Census Bureau term which refers to a house, apartment, mobile home, group of rooms or single room intended for occupancy, which is occupied. Occupied housing units provide a reasonable estimate for the number of PSE customers in a given census tract.

RESILIENCY. The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event.[3]

3 / https://grouper.ieee.org/groups/transformers/subcommittees/distr/C57.167/F18-Definition&QuantificationOfResilience.pdf

2. METHODOLOGY

The EHEB Assessment results in two primary work products: 1) identification of named populations and 2) assessment of disparities between named populations and a "typical PSE customer." Each of these work products is related to the other, but each is a distinct deliverable.

For this IRP, PSE elected to perform a geographic analysis for both components of the Assessment. All data used in the Assessment were aggregated to the census tract level and reported as averages by census tract. Census tracts are a geographic unit delineated by the United States Census Bureau. Census tracts are small, relatively permanent subdivisions of a county which generally contain populations between 1,200 and 8,000 people, with an ideal size of around 4,000 people. The land area of a census tract can vary drastically because population is the primary driver behind the delineation of the unit.

Census tracts are useful for this type of assessment for a number of reasons. Demographic, public health, economic, environmental and other types of data are often readily available by census tract, which allows for meaningful comparisons between data types and streamlined data processing into Assessment frameworks. Census tracts are generally small enough to provide better insight into individual communities than lower resolution subdivisions such as zip code or county. Census tracts are also relatively stable over time, which allows for trend analysis over multiple Assessment cycles.

PSE acknowledges that a geographic assessment includes limitations. Aggregating data into fixed geographies often ignores the distribution of characteristics across a population within a given geography. Additionally, some data sources that transcend geographic boundaries pose problems in a geographic assessment, such as job creation or community-wide electric vehicle charging stations. PSE expects this Assessment to evolve over time to overcome some or all of these limitations. PSE will explore determining customer groups by characteristics, rather than geographically designated information, in future IRPs. Please see the Future Work section at the end of this appendix for more information specific actions PSE plans to implement in future EHEB Assessments.

Identification of Named Populations

Named populations include highly impacted communities and vulnerable populations (see above definitions). In this IRP, named populations are represented as census tracts which meet specific criteria. The following sections detail the criteria used for each named population.

Also included below is a description of the "typical PSE customer." While not a named population under CETA rule, the typical PSE customer is an important component of the EHEB Assessment for defining a baseline comparison.

Typical PSE Customer

The typical PSE customer is used to represent the status quo for most PSE customers. Any time a metric or measure refers to the typical PSE customer, it is referring to the average of all census tracts across PSE's electric service territory.

The typical PSE customer will serve as a baseline from which to measure current disparities.

Vulnerable Populations

Vulnerable populations attributes are intended to describe disproportionate cumulative risk from burdens due to:

- Adverse socioeconomic factors including unemployment, high housing and transportation costs relative to income, access to food and health care, and linguistic isolation; and
- sensitivity factors, such as low birth weight and higher rates of hospitalization.

The Washington State Department of Health developed a health disparities map and composite score as defined in the Washington Environmental Health Disparities report.[4] In the report, vulnerability is represented by indicators of socioeconomic factors and sensitive populations. The attributes listed under the sensitive populations and socioeconomic factors closely align with the definition of vulnerable populations in the rulemaking and are illustrated in Figure K-3. PSE selected the attributes from this list, as shown in Figure K-4.

4 / *https://www.doh.wa.gov/DataandStatisticalReports/WashingtonTrackingNetworkWTN/InformationbyLocation/WashingtonEnvironmentalHealthDisparitiesMap*

Figure K-3: Indicators, Washington Environmental Health Disparities Map

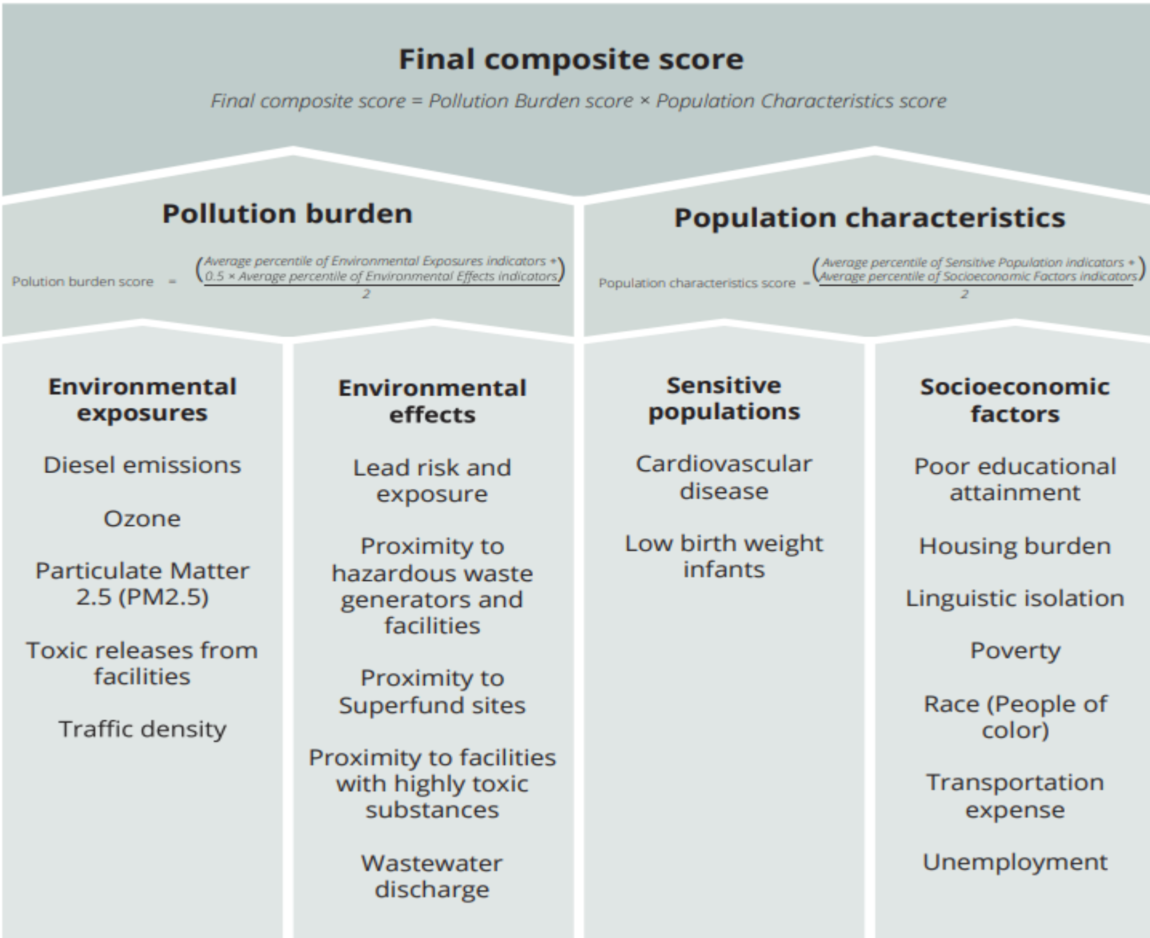


Figure credit: University of Washington Department of Environmental & Occupational Health Sciences. Washington Environmental Health Disparities Map: technical report. Seattle; 2019.

Figure K-4: PSE EHEB Attributes for Vulnerable Populations

Indicators	Specific Attribute
Sensitive Populations	Cardiovascular disease
	Low birth weight
Socioeconomic Factors	Housing burden
	Linguistic isolation
	Poverty
	Transportation expense
	Unemployment

Data Source for all attributes: Washington Department of Health Washington Tracking Network Query Portal (https://fortress.wa.gov/doh/wtn/WTNPortal/)

PSE has averaged the score for each of the attributes above and sorted these average scores by ranked percentile. The ranked percentile score for each census tract is then converted to a 1-10 score where a score of 1 is assigned to the ranked percentile between 0 percent and 10 percent, 2 is assigned to the ranked percentile 10 percent to 20 percent, and so on.

PSE has chosen an average score of 9 or 10 to define a vulnerable population, which was influenced by the scoring criteria established for highly impacted communities in the Cumulative Impact Analysis discussed below. PSE may further refine the scoring criteria for vulnerable populations based on future stakeholder feedback.

Highly Impacted Communities

Highly Impacted Communities (HICs) are defined by the Washington Department of Health Cumulative Impact Analysis (CIA) and identified as census tracts with an overall score on the Environmental Health Disparities (EHD)[5] Map of 9 or 10.[6] The CIA was recently published, and PSE expects additional WUTC rulemaking in 2021 to provide more guidance on the application of the CIA in the IRP and CEIP processes. For this IRP, PSE did its best to utilize the CIA in the absence of this specific rulemaking.

Tribes have been defined by the CIA as census tracts that are fully or partially on “Indian Country” as defined in 18 U.S.C. Sec. 1151. PSE obtained Tribal Census Tract data from the U.S. Census Bureau TIGERweb map server for Tribal Census Tracts and Block Groups. Any census tracts that intersect areas identified in this dataset are designated as tribal lands and have been included as Highly Impacted Communities per CIA guidance.

5 / https://fortress.wa.gov/doh/wtn/WTNIBL
4 / https://www.doh.wa.gov/DataandStatisticalReports/WashingtonTrackingNetworkWTN/ClimateProjections/CleanEnergyTransformationAct

The CIA incorporated a "Climate Projections 2050" layer into the EHD Map that includes temperature and precipitation change projections as a result of climate change. However, the CIA notes there is limited literature to support inclusion of these projections into present day public health measures used in the EHD Map. Therefore, the Climate Projections 2050 data has not been incorporated into the criteria to define HICs in PSE's Assessment.

Measurement of Disparities

The second work product of the Assessment is to measure disparities of customer benefit indicators across PSE's service area. Disparities were measured at the census tract level, as well as aggregated to the average score of each group: typical PSE customers, highly impacted communities and vulnerable populations.

As required by the CETA legislation and IRP/CEIP rulemaking, customer benefit indicators will span the areas of public health, environment, economic factors, energy security and resiliency, and energy and non-energy benefits. The purpose of these indicators is to quantify existing conditions observed across PSE's customers in order to evaluate disparities between populations within each customer base. PSE developed an initial set of indicators presented in Figure K-5.

Figure K-5: Summary of Customer Benefit Indicators

Category	Customer Benefit Indicator	Definition	Data Source
Public Health	Particulate Matter Emissions	Total emissions from all sources. Data representative of the sum of primary species of Particulate Matter 2.5 µm and Particulate Matter 10 µm.	U.S. Environmental Protection Agency 2017 National Emissions Inventory https://www.epa.gov/air-emissions-inventories/2017-national-emissions-inventory-nei-data
	SO_2 Emissions	Total emissions from all sources.	U.S. Environmental Protection Agency 2017 National Emissions Inventory https://www.epa.gov/air-emissions-inventories/2017-national-emissions-inventory-nei-data
	NO_x Emissions	Total emissions from all sources.	U.S. Environmental Protection Agency 2017 National Emissions Inventory https://www.epa.gov/air-emissions-inventories/2017-national-emissions-inventory-nei-data

Category	Customer Benefit Indicator	Definition	Data Source
	Environmental Health Disparities Map Overall Score	Representative of overall environmental health disparities across Washington state due to Environmental Exposures, Environmental Effects, Socioeconomic Risk Factors and Sensitive Population Risk Factors.	Wash. Department of Health (Washington Tracking Network) https://fortress.wa.gov/doh/wtn/WTNIBL
Environment	Solar Choice participation	Number of PSE customers enrolled in Solar Choice programs	PSE
	Green Power participation	Number of PSE customers enrolled in the Green Power program	PSE
Economic Factors	Energy Burden	Percentage of household income spent on energy	Department of Energy LEAD Tool https://www.energy.gov/eere/slsc/maps/lead-tool
	Poverty	Percent of population living below 185% the federal poverty level	Wash. Department of Health (Washington Tracking Network) https://fortress.wa.gov/doh/wtn/WTNIBL
	Unemployment	Percentage of the population in the labor force and registered as unemployed	Wash. Department of Health (Washington Tracking Network) https://fortress.wa.gov/doh/wtn/WTNIBL
	Net Metering	Number of PSE customers participating in Net Metering program	PSE
Energy Security & Resiliency	Distribution Redundancy	*Percent of PSE-owned circuits equipped with redundancy features*	PSE
	Distribution Automation	*Percent of PSE-owned circuits equipped with automation*	
Non-energy Benefits	Residential EV hookups	*Number of known PSE customers with EV charging stations by resident*	PSE

Disparities in the Assessment are represented as relative "disparity scores." A disparity score is a measure of the burden of one community as it relates to the general population. Disparity scores are presented on a scale from 1 to 10, where a score of 1 represents the least burdened (or most benefited) communities and a score of 10 represents the most burdened (or least benefited) communities.

The disparity score of a community is calculated based on the ranked percentile of the community against the rest of the communities in the population. Generally, data for specific customer benefit indicators are aggregated to the census tract geospatial resolution. The values for all the census tracts in either Washington state or PSE's service territory (depending on the scope of the data) are ranked from least burdened to most burdened. The census tracts in the 0-10 percent of the rankings are assigned a score of 1, the census tracts in the 10-20 percent of the rankings are assigned a score of 2 and so on.

Disparity scores are useful because they allow for simple comparisons between different data types. For example, you can easily compare disparities between particulate matter emissions and unemployment, even though these two data types would typically have different units of measure and magnitudes. Disparity scores also allow for combination of disparate data types – for example, if you were interested in the disparity of all air quality measures instead of particulate matter, SO_2 and NO_x separately.

The primary drawback of disparity scores is that they are only relative measures; they show differences between communities, but do not show the magnitude of those differences. Since the magnitude of disparities is obscured by the ranking system, analysts must return to the source data to understand how much more burdened a score of 10 is than a score of 1.

3. RESULTS

Identification of Named Populations Results

Figure K-6 shows the census tracts across PSE's service area which have been identified as named populations. The figure shows three maps. The first map shows all of the census tracts which compose PSE's electric service territory highlighted in teal. PSE's electric service territory encompasses 489 census tracts in western Washington.

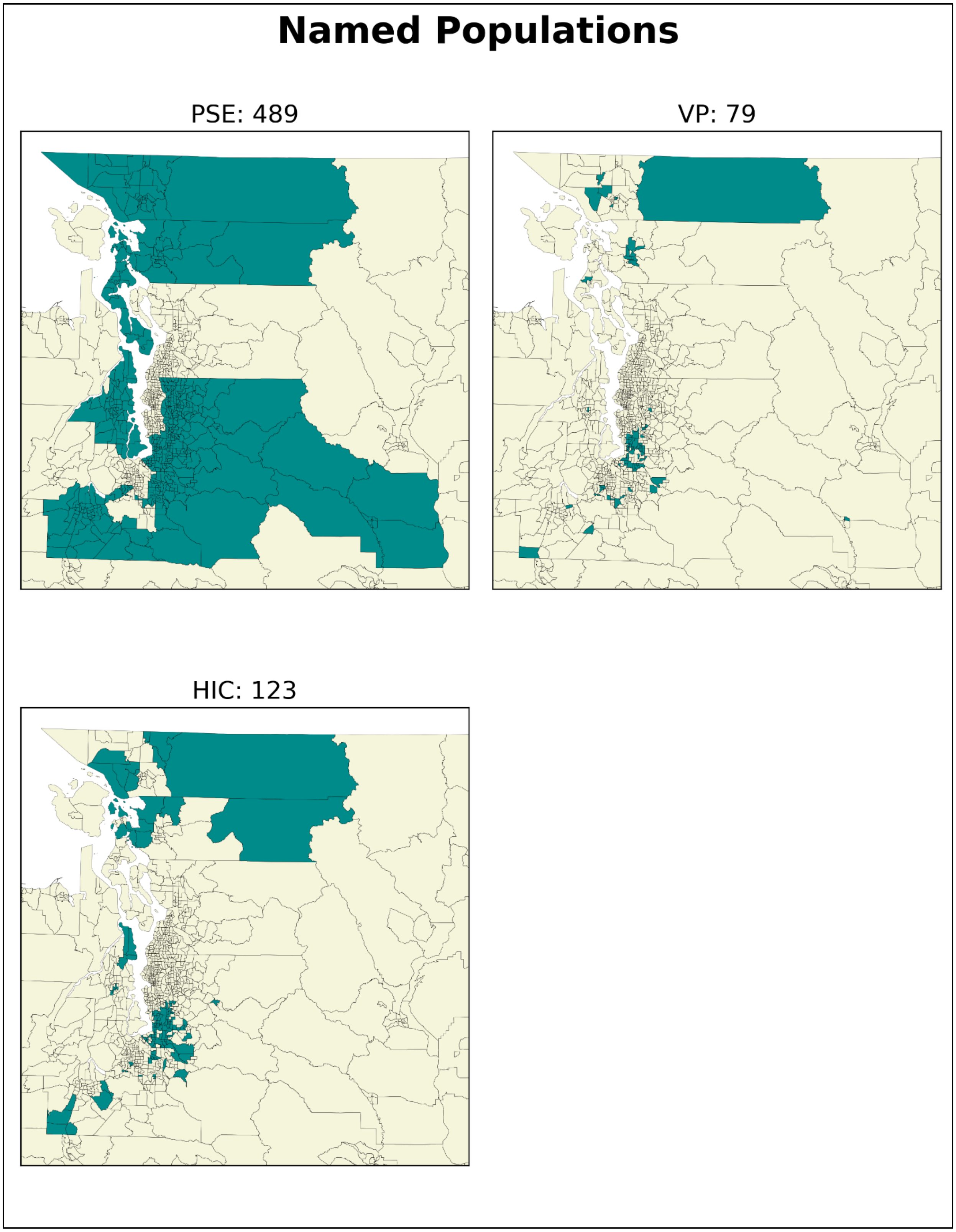
The second map, in the upper right, shows the census tracts identified as vulnerable populations, highlighted in teal. The Assessment identified 79 census tracts which met the criteria to be designated a vulnerable population. On the basis of occupied housing units within these census tracts, vulnerable populations account for approximately 17 percent of PSE's customers.

The third map, in the lower left, shows the census tracts identified as highly impacted communities, highlighted in teal. The Assessment identified 123 census tracts which met the criteria to be designated a highly impacted community. On the basis of occupied housing units within these census tracts, highly impacted communities account for approximately 25 percent of PSE's customers.

There is considerable overlap between census tracts identified as vulnerable populations and highly impacted communities. Of the 79 census tracts identified as vulnerable populations, 55 census tracts were also identified as highly impacted communities. This result is not surprising, as many of the criteria used to identify highly impacted communities are also used to identify vulnerable populations.

Generally, vulnerable populations tend to be more urban than highly impacted communities. This is largely due to the inclusion of tribal lands in the highly impacted community criteria, which tend to be on rural lands. Of the 123 census tracts identified as highly impacted communities, 47 census tracts intersect with tribal lands.

Figure K-6: Named Populations



Measurement of Disparities Results

The disparity measurement results are presented in a similar manner to the named population results above, where each map corresponds to a specific named population. Each census tract is color-coded to a specific disparity score between 1 and 10, where low disparity scores are deeper blue and high disparity scores are deeper red. Next to each map title is a number which represents the average disparity score for that named population. This number is the average of all the individual census tract disparity scores shown on the map for that named population.

The following discussion of the disparity measurement results includes important notes about the data used to assess that customer benefit indicator, interpretation of any disparities identified and initial observations on how this information may be used to develop a more equitable electric portfolio in the future.

Particulate Matter Emissions

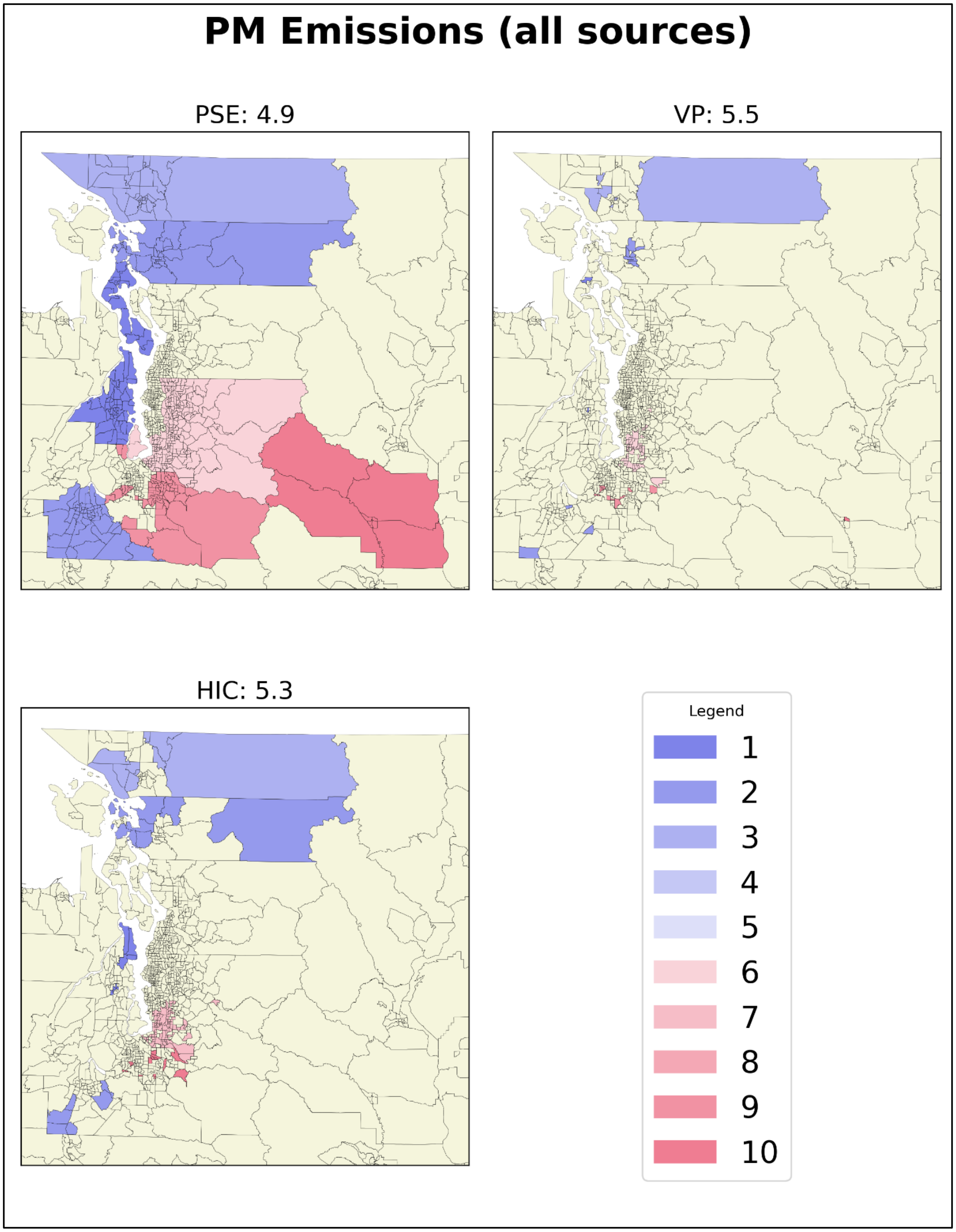
Figure K-7 shows the disparity score results for particulate matter (PM) emissions. Data for PM were obtained from the U.S. Environmental Protection Agency 2017 National Emissions Inventory (NEI). Data are representative of the average annual emissions for the year 2017. The NEI is updated on a three-year cycle. The NEI aggregates data from numerous sources for many different air quality pollutants. The data used for this Assessment represents total emissions, in tons, from all sectors. Sectors span a number of emitting sources such as agricultural practices, electricity generation, industrial processes and others. Please refer to the NEI Technical Support Document for further detail.[7] PM may be reported in different ways. The data used in this study includes the sum of filterable and condensable PM for particle sizes of both 2.5 μm and 10μm. PM may be inhaled and is linked to health problems including aggravated asthma, decreased lung function and nonfatal heart attacks.

PM data is reported by the NEI at the county level, therefore, all census tracts within each county have been assigned the same disparity score. PM data was collected for the entirety of Washington state. The average Washingtonian would have a disparity score of between 5 and 6. Figure K-7 shows that the typical PSE customer has a disparity score of 4.9, which means the typical PSE customer experiences slightly less PM pollution than a typical Washingtonian.

PM disparities are highest in inland census tracts which are susceptible to wildfire and agricultural burning smoke, which both generate large quantities of PM. Urban areas also have higher PM disparities resulting from higher densities of sources like traffic, construction sites and industrial processes. These urban impacts result in higher disparities for PSE's vulnerable populations and highly impacted communities, with scores of 5.5 and 5.3, respectively. This shows that the named populations are slightly more impacted than the typical PSE customer.

7 / https://www.epa.gov/sites/production/files/2021-02/documents/nei2017_tsd_full_jan2021.pdf

Figure K-7: Particulate Matter Emissions



SO_2 Emissions

Figure K-8 shows the disparity score results for sulfur dioxide (SO_2). Data for SO_2 were obtained from the U.S. Environmental Protection Agency 2017 National Emissions Inventory (NEI) and are representative of the average annual emissions for the year 2017. The NEI is updated on a three-year cycle. The NEI aggregates data from numerous sources for many different air quality pollutants. The data used for this assessment represents total emissions, in tons, from all sectors. Sectors span a number of emitting sources such as agricultural practices, electricity generation, industrial processes and others. Please refer to the NEI Technical Support Document for further detail.[8] SO_2 has the potential to react with other compounds in the air giving rise to particles which result in increased PM. If inhaled, SO_2 may cause respiratory discomfort. SO_2 also contributes the creation of acid rain.

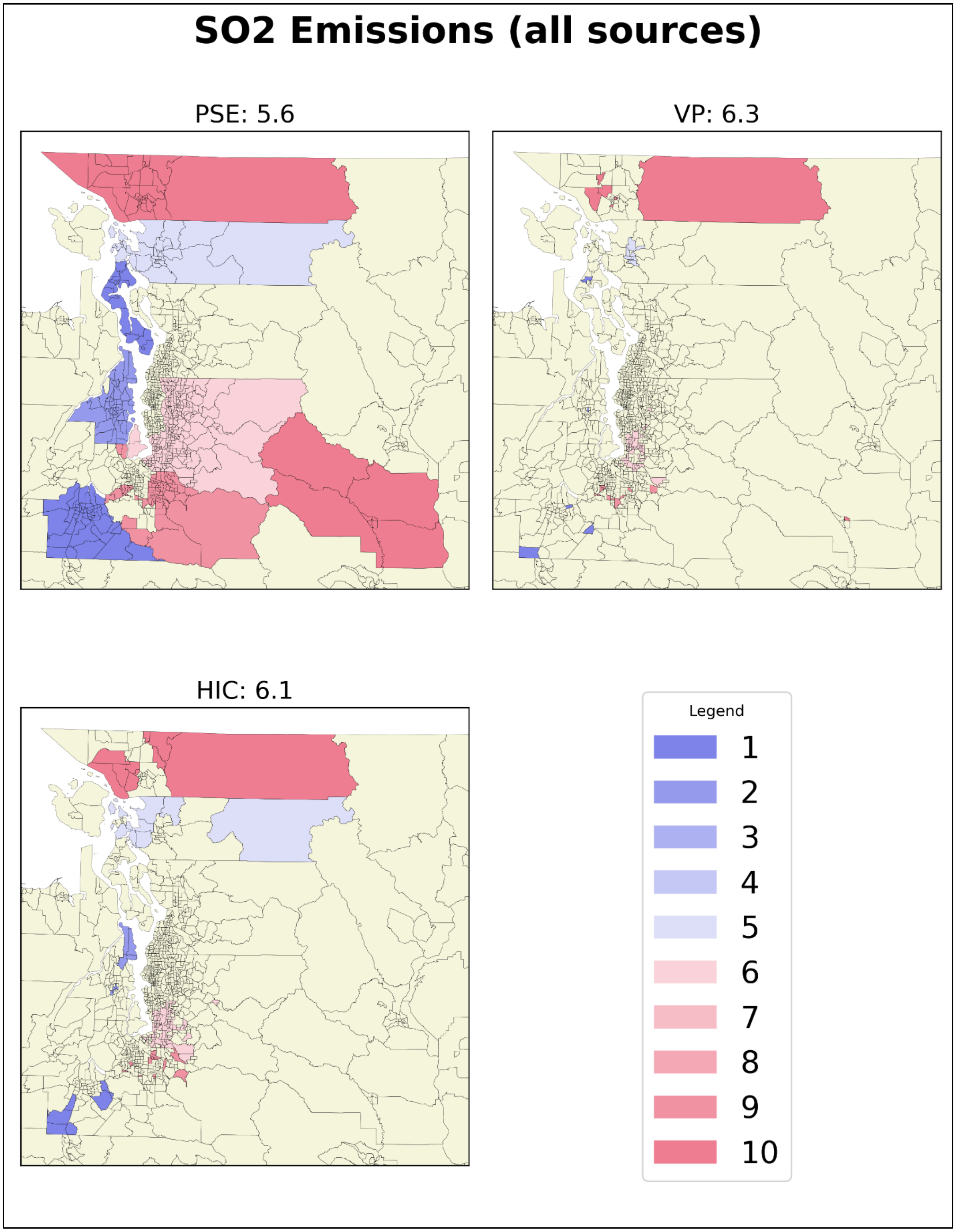
SO_2 data is reported by the NEI at the county level, therefore, all census tracts within each county have been assigned the same disparity score. SO_2 data was collected for the entirety of Washington state. The average Washingtonian would have a disparity score of between 5 and 6. Figure K-8 shows that the typical PSE customer has a disparity score of 5.6, which means the typical PSE customer experiences about the same SO_2 burden as a typical Washingtonian.

SO_2 disparities are highest in urban census tracts, and Kittitas County also has a high SO_2 disparity.

The urban SO_2 impacts result in higher disparities for PSE's vulnerable populations and highly impacted communities, with scores of 6.3 and 6.1, respectively. This shows that the named populations are slightly more impacted than the typical PSE customer.

8 / https://www.epa.gov/sites/production/files/2021-02/documents/nei2017_tsd_full_jan2021.pdf

Figure K-8: SO_2 Emissions



NO_X Emissions

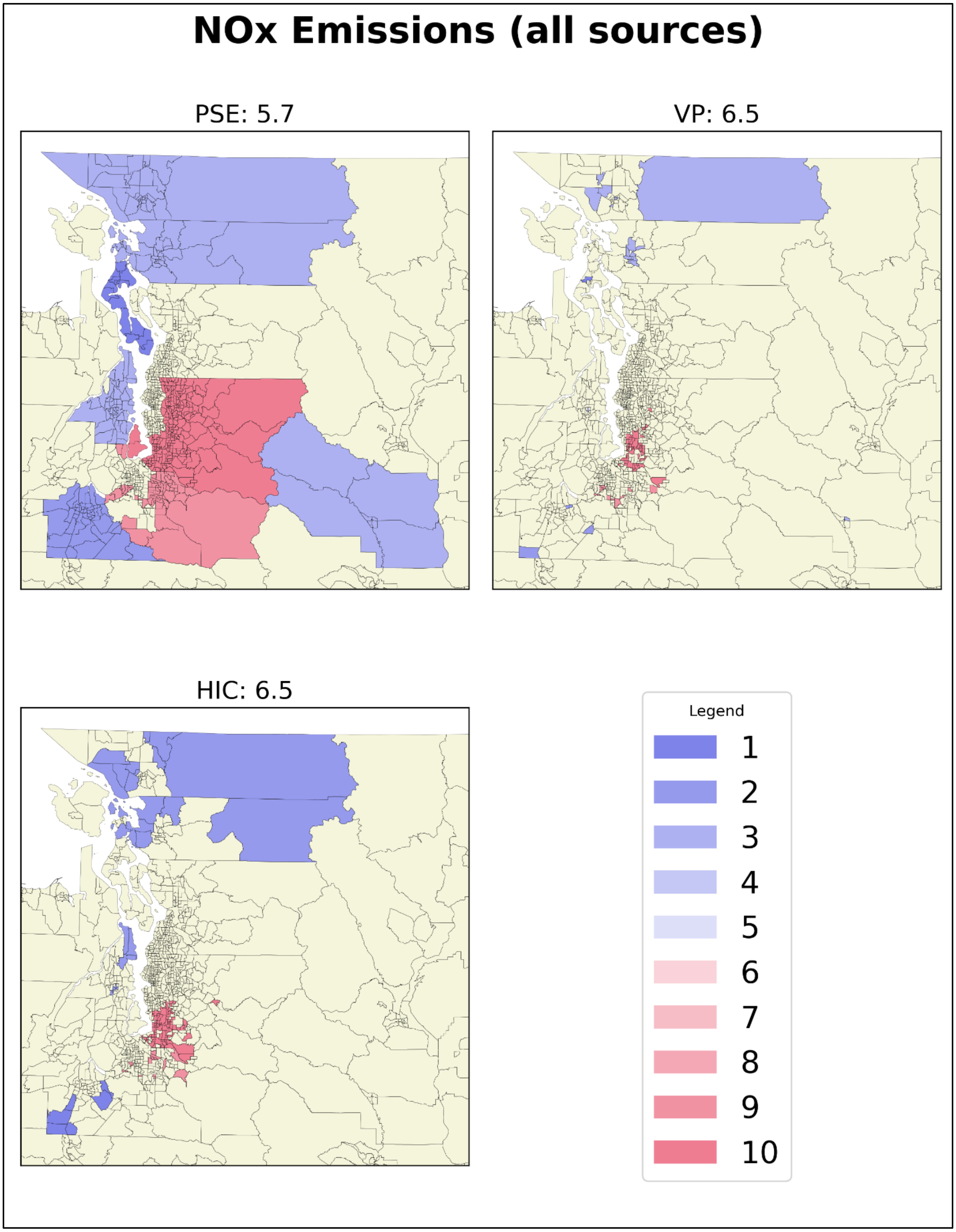
Figure K-9 shows the disparity score results for nitrous oxides (NO_x). Data for NO_x were obtained from the U.S. Environmental Protection Agency 2017 National Emissions Inventory (NEI) and are representative of the average annual emissions for the year 2017. The NEI is updated on a three-year cycle. The NEI aggregates data from numerous sources for many different air quality pollutants. The data used for this assessment represents total emissions, in tons, from all sectors. Sectors span a number of emitting sources such as agricultural practices, electricity generation, industrial processes and others. Please refer to the NEI Technical Support Document for further detail.[9] NO_x has the potential to react with other compounds in the air giving rise to particles which result in increased PM. If inhaled, NO_x may cause respiratory discomfort. NO_x also contributes the creation of acid rain.

NO_x data is reported by the NEI at the county level, therefore, all census tracts within each county have been assigned the same disparity score. NO_x data was collected for the entirety of Washington state. The average Washingtonian would have a disparity score of between 5 and 6. Figure K-9 shows that the typical PSE customer has a disparity score of 5.7, which means the typical PSE customer experiences about the same NO_x burden as a typical Washingtonian.

NO_x disparities are highest in urban census tracts. The urban NO_x impacts result in higher disparities for PSE's vulnerable populations and highly impacted communities, with scores of 6.5 for both named populations. This shows that the named populations are more impacted than the typical PSE customer.

9 / *https://www.epa.gov/sites/production/files/2021-02/documents/nei2017_tsd_full_jan2021.pdf*

Figure K-9: NO_x Emissions



Environmental Health Disparities Map Overall Score

Figure K-10 shows the disparity score results for the Environmental Health Disparities (EHD) Map overall score. Data for the EHD Map overall score were obtained from the Washington Department of Health Washington Tracking Network. The overall score is a composite index of public health burden from environmental effects and exposures to sensitive populations. The EHD Map overall score touches on a number of public health indicators, provided in Figure K-10. Please refer to the EHD Map Report for further detail on each of these indictors.[10]

Figure K-10: Environmental Health Disparities Map Overall Score Indicators

Category	Indicator
Environmental Exposures	NOx-Diesel Emissions
	Ozone Concentration
	PM2.5 Concentration
	Populations near Heavy Traffic Roadways
	Toxic Releases from Facilities
Environmental Effects	Lead Risk from Housing
	Proximity to Hazardous Waste Treatment Storage and Disposal Facilities
	Proximity to National Priorities List Facilities
	Proximity to Risk Management Plan Facilities
	Wastewater Discharge
Socioeconomic Factors	ACS: Limited English
	No High School Diploma
	Population Living in Poverty <= 185% of Federal Poverty Level
	Transportation Expense
	Unaffordable Housing (>30% of income)
	Unemployed
Sensitive Populations	Death from Cardiovascular Disease
	Low Birth Weight

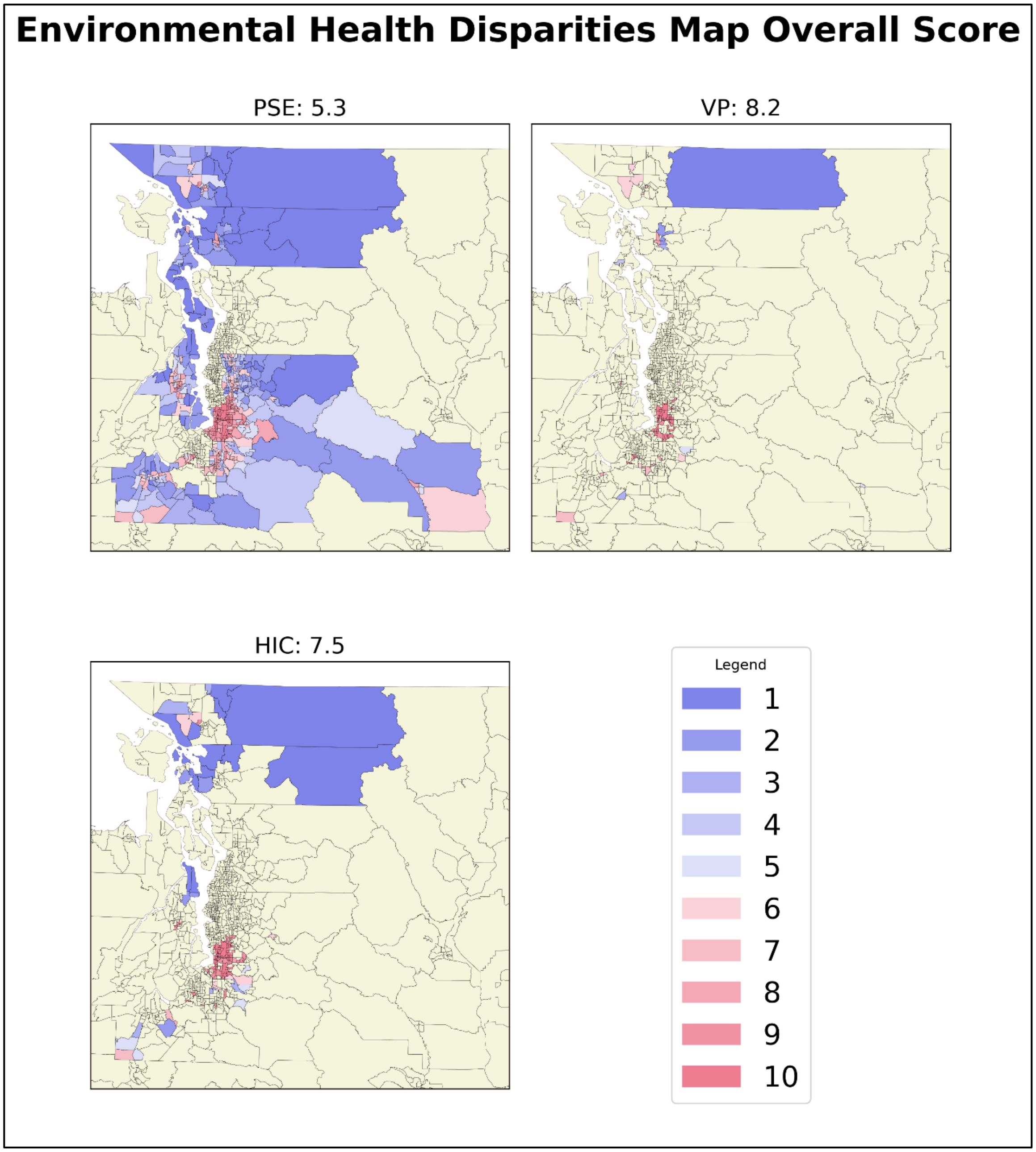
10 / *https://deohs.washington.edu/sites/default/files/images/Washington_Environmental_Health_Disparities_Map.pdf*

EHD map data is reported at the census tract level for the entirety of Washington state. The average Washingtonian would have a disparity score of between 5 and 6. Figure K-11 shows that the typical PSE customer has a disparity score of 5.3, which means the typical PSE customer experiences about the same environmental public health burden as a typical Washingtonian.

Urban areas have the highest environmental public health burden according to the EHD map overall score. The urban impacts result in higher disparities for PSE’s vulnerable populations and highly impacted communities, with scores of 8.2 and 7.5 for vulnerable populations and highly impacted communities, respectively. This shows that the named populations are more impacted than the typical PSE customer.

Many of the same indicators used to develop the EHD Map overall score are also used to identify highly impacted communities and vulnerable populations. This explains why vulnerable populations and highly impacted communities show such a significantly higher burden than the typical PSE customer.

Figure K-11: Environmental Health Disparities Map Overall Score



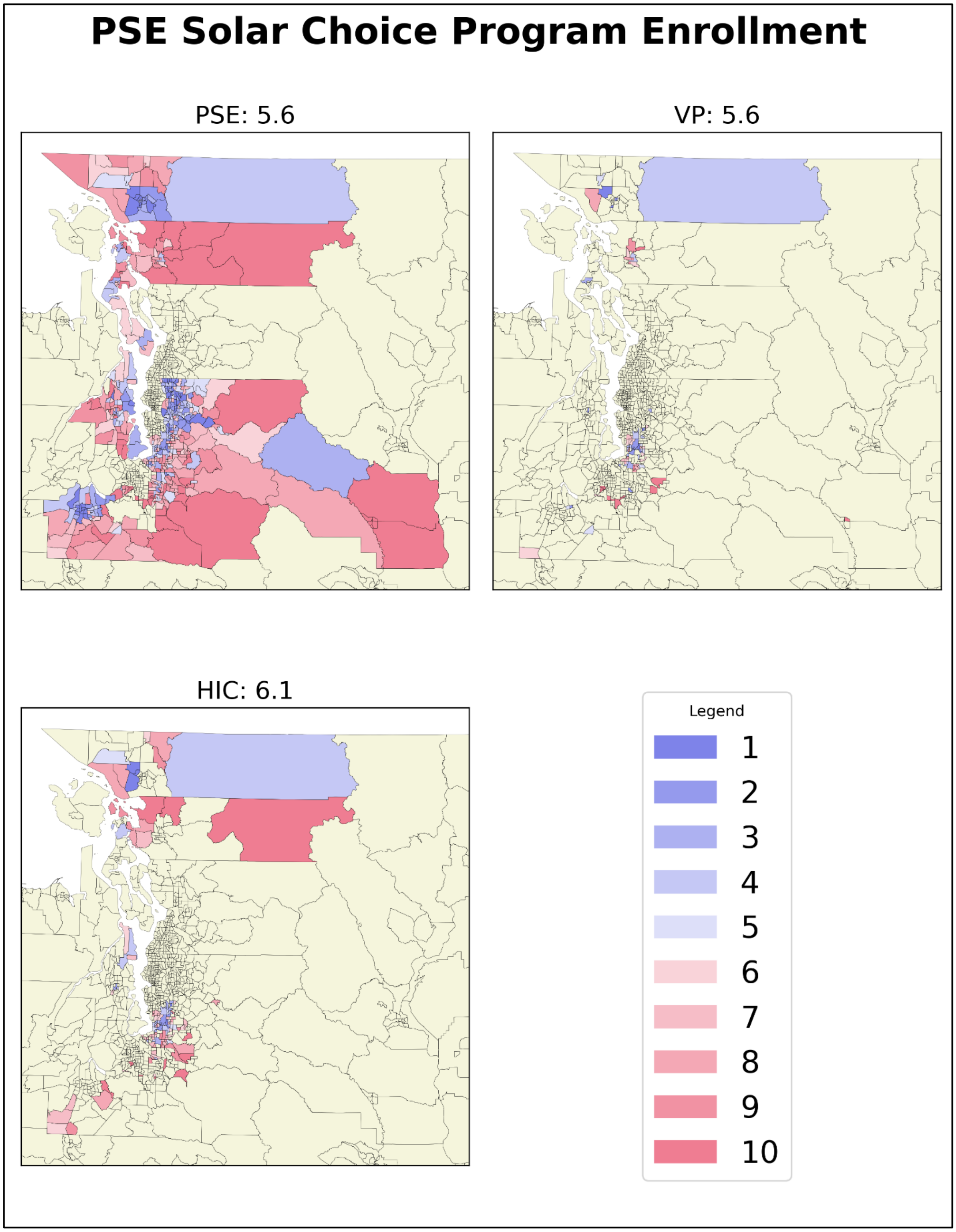
Solar Choice Enrollment

Figure K-12 shows the disparity score results for PSE's Solar Choice program. The Solar Choice program allows PSE customers to pay a premium on their bill to source a portion of their energy from solar facilities. Enrollment is voluntary. Data for Solar Choice enrollment were obtained from PSE records. Solar Choice enrollment is modeled as a customer benefit, therefore lower scores correspond to higher program enrollment and higher scores with lower program enrollment.

Individual customer enrollment was aggregated at the census tract level. Solar Choice enrollment data was only available for PSE customers, therefore it is not possible to compare scores to the average Washingtonian. The typical PSE customer has a disparity score of 5.7, which falls into the expected range of 5 to 6.

Solar Choice enrollment disparities are greatest in rural areas of PSE service territory. Vulnerable populations have an average disparity score of 5.6, equal to that of the typical PSE customer, which indicates no disparity between the typical PSE customer and vulnerable populations. However, highly impacted communities have an average disparity score of 6.1, which is higher than the typical PSE customer, suggesting that highly impacted communities experience this benefit less than the typical PSE customer.

Figure K-12: Solar Choice Program Enrollment



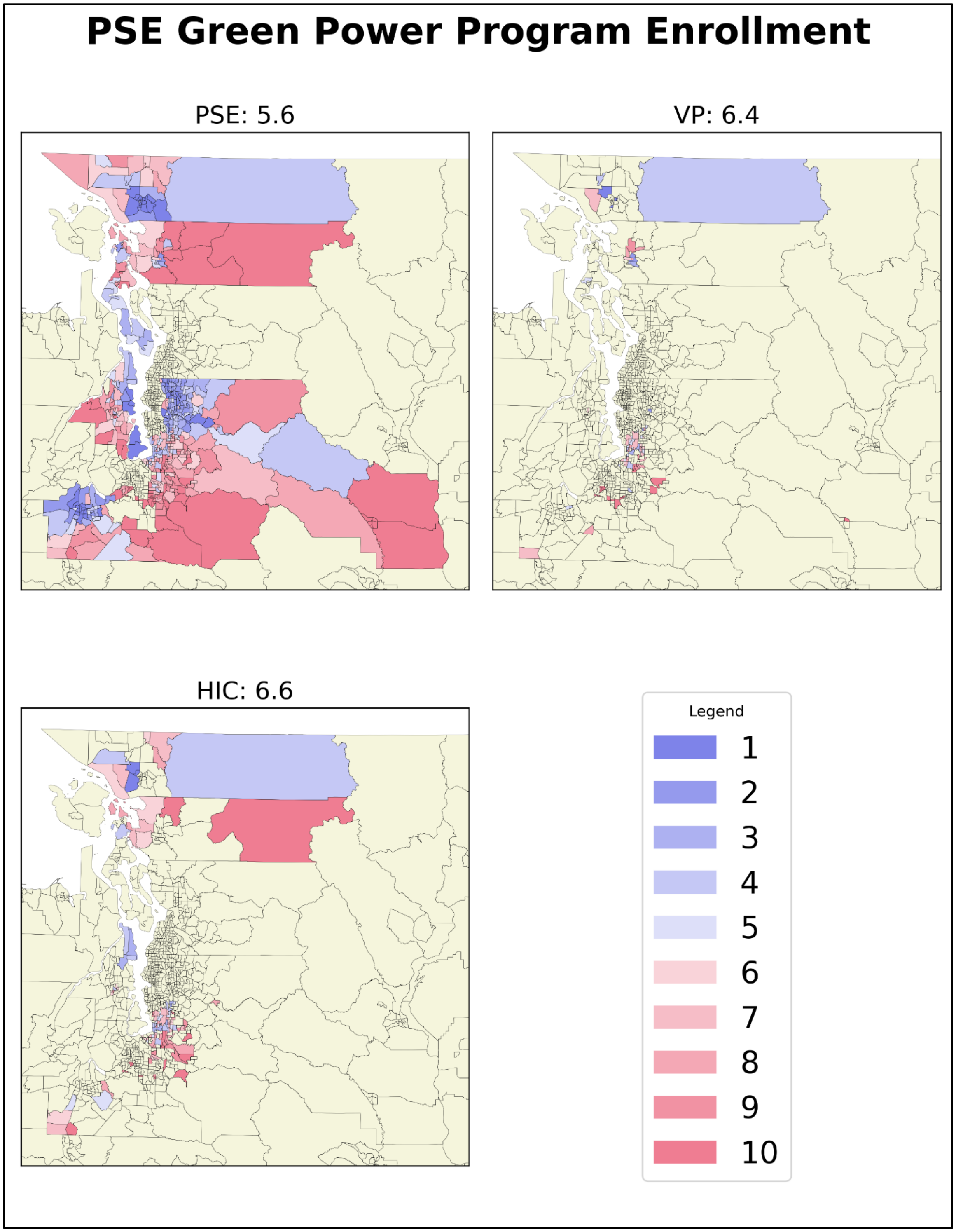
Green Power Enrollment

Figure K-13 shows the disparity score results for PSE's Green Power program. The Green Power program allows PSE customers to pay a premium on their bill to source a portion of their energy from renewable generation facilities. Enrollment is voluntary. Data for Green Power enrollment were obtained from PSE records. Green Power enrollment is modeled as a customer benefit, therefore lower scores correspond to higher program enrollment and higher scores with lower program enrollment.

Individual customer enrollment was aggregated at the census tract level. Green Power enrollment data was only available for PSE customers, therefore it is not possible to compare scores to the average Washingtonian. The typical PSE customer has a disparity score of 5.6, which falls into the expected range of 5 to 6.

Green Power enrollment disparities are greatest in rural areas of PSE service territory. Vulnerable populations and highly impacted communities have higher disparity scores than the typical PSE costumer at 6.4 and 6.6, respectively. This suggests that named populations experience this benefit less than the typical PSE customer.

Figure K-13: Green Power Program Enrollment



Energy Burden

Figure K-14 shows the disparity score results for energy burden. Data for energy burden were obtained from the U.S. Department of Energy Low-Income Energy Affordability Data (LEAD) Tool.[11] The LEAD Tool leverages data from the 2016 5-year American Community Survey to estimate energy burden in communities across the United States. Energy burden is a measure of the percent of income spent on residential housing energy. Residential housing energy includes electricity, gas and other fuels. Transportation energy is not included in energy burden. The LEAD tool allows users to filter data to identify relationships over a number of factors including income level, building age, heating fuel type, building type and tenure. Energy burden data for this Assessment did not filter criteria and therefore includes all income levels, all building ages, all heating fuel types, all building types, and both renter- and owner-occupied housing.

Energy burden data is reported by the LEAD Tool at the census tract level for the entirety of Washington state. Therefore, the average Washingtonian would have a disparity score of between 5 and 6. Figure K-14 shows that the typical PSE customer has a disparity score of 3.2, which suggests the typical PSE customer experiences a significantly lower energy burden than a typical Washingtonian.

Energy burden tends to be highest in rural areas. This is a well-established trend across the United States and has been attributed to factors including high concentrations of low-income households, prevalence of inefficient manufactured homes, use of propane or fuel oil for heating and lack of program resources.[12] PSE's vulnerable populations and highly impacted communities, with scores of 3.6 and 3.8, respectively, have higher energy burdens than the typical PSE customer, but still well below the typical Washingtonian. This shows that PSE customers have, on average, lower-cost bills than most Washington residents.

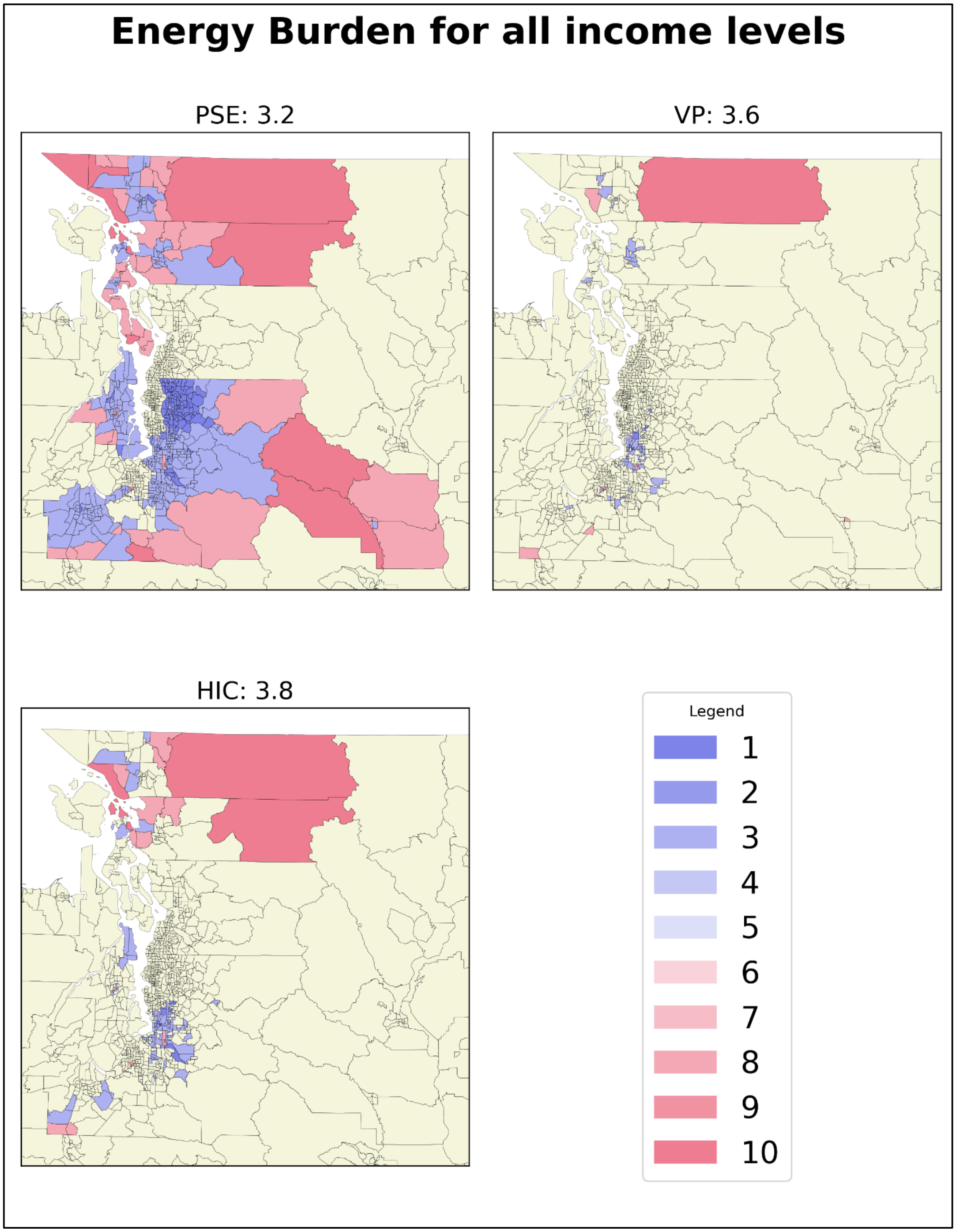
11 / https://www.energy.gov/eere/slsc/maps/lead-tool
12 / https://www.aceee.org/sites/default/files/publications/researchreports/u1806.pdf

PSE is continuing to develop and expand its low-income weatherization and energy assistance programs. As identified in the Low-Income Household Needs Assessment[13] prepared by Cadmus for PSE, several steps have been outlined to continue to improve assistance to low-income households. These steps include:

- further research to understand factors contributing to lack of participation in underserved groups
- deeper analysis into customer segmentation to better understand characteristics of underserved groups
- develop new strategies to inform targeted outreach to underserved groups
- use the new tools/strategies developed to support new pilots and programs to reach underserved groups

13 / Low-Income Household Needs Assessment, Oct 2020, available from Washington Utilities and Transportation Commission Documents and Proceedings document management system upon request

Figure K-14: Energy Burden



Poverty

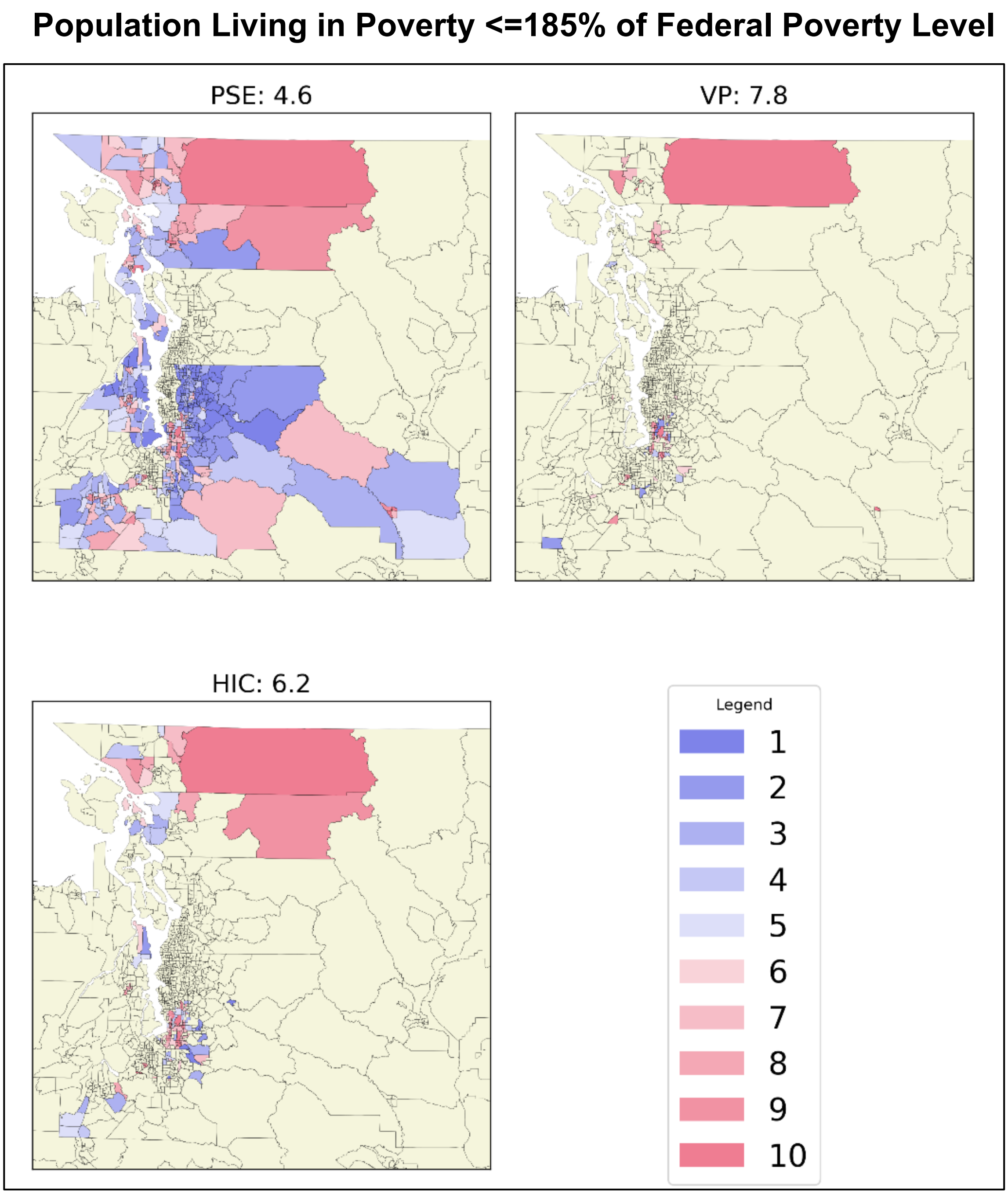
Figure K-15 shows the disparity score results for poverty. Data for poverty were obtained from the Washington Tracking Network Query Portal.[14] The data are a measure of the percent of the population in any census tract living with household income less than or equal to 185 percent of the federal poverty level. Income data were obtained from American Community Survey 5-year rollup.

Poverty data is reported by the Washington Tracking Network at the census tract level for the entirety of Washington state. The average Washingtonian would have a disparity score of between 5 and 6. Figure K-15 shows that the typical PSE customer has a disparity score of 4.6, which suggests the typical PSE customer experiences less poverty burden than a typical Washingtonian.

Poverty burden is mixed throughout both urban and rural communities. PSE's vulnerable populations and highly impacted communities, with scores of 7.8 and 6.2, respectively, have significantly higher poverty burdens than the typical PSE customer. This result is expected, considering poverty burden is an indicator used to identify both highly impacted communities and vulnerable populations.

14 / https://fortress.wa.gov/doh/wtn/WTNPortal#!q0=3625

Figure K-15: Poverty



Unemployment

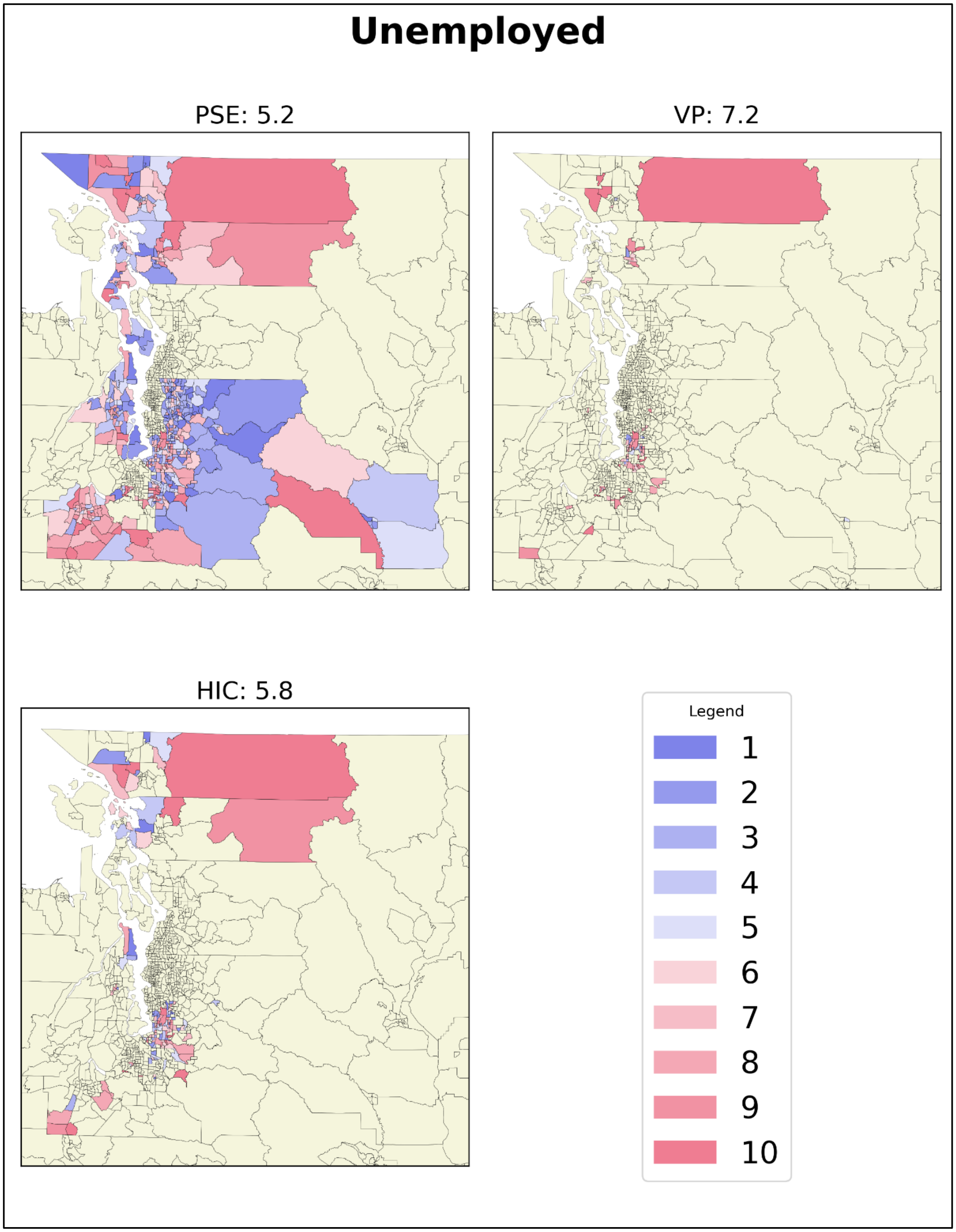
Figure K-16 shows the disparity score results for unemployment. Data for unemployment were obtained from the Washington Tracking Network Query Portal[15] and are a measure of the percent of the working population over 16 years old in any census tract who are currently unemployed. Unemployment data were obtained from American Community Survey 5-year rollup.

Unemployment data is reported by the Washington Tracking Network at the census tract level for the entirety of Washington state. Therefore, the average Washingtonian would have a disparity score of between 5 and 6. Figure K-16 shows that the typical PSE customer has a disparity score of 5.2, which suggests the typical PSE customer experiences unemployment burden about the same as a typical Washingtonian.

Unemployment burden is mixed throughout both urban and rural communities. PSE's vulnerable populations and highly impacted communities, with scores of 7.2 and 5.8, respectively, have higher unemployment burden than the typical PSE customer. This result is expected, considering unemployment burden is an indicator used to identify both highly impacted communities and vulnerable populations.

15 / https://fortress.wa.gov/doh/wtn/WTNPortal#!q0=3625

Figure K-16: Unemployment



Net Metering Installations

Figure K-17 shows the disparity score results for PSE customers who have installed net metering equipment at their homes. Net metering equipment is installed voluntarily, at the customer's expense. Data for net metering installations were obtained from PSE records. Net metering installations are modeled as a customer benefit, therefore lower scores correspond to higher program enrollment and higher scores with lower program enrollment.

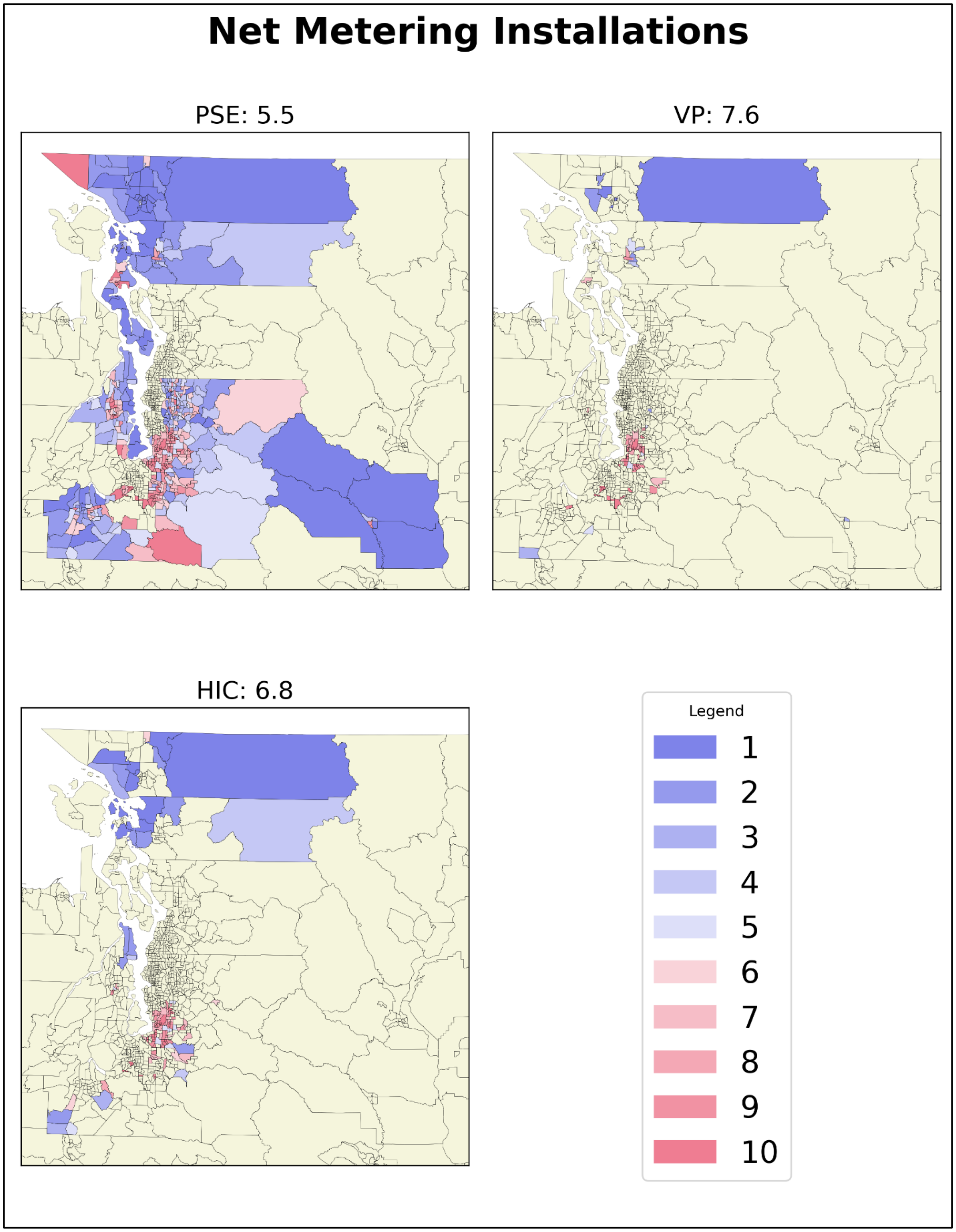
Net metering installations are an indicator of residential energy generation rates across PSE's service territory, such as rooftop solar installations. Residential energy generation may reduce energy burdens through reduced energy bills and improve air quality through load reductions of thermal resources, and it may also increase benefits such as energy resiliency through increased distributed generation and property values through property improvement.

Individual customer data was aggregated at the census tract level. Net metering installation data was only available for PSE customers, therefore it is not possible to compare scores to the average Washingtonian. The typical PSE customer has a disparity score of 5.5, which falls within the expected range of 5 to 6.

Net metering installation disparities are greatest in urban areas of PSE service territory. This may be correlated with higher rates of tenancy and more constrained space.

Vulnerable populations and highly impacted communities have higher disparity scores than the typical PSE costumer at 7.6 and 6.8, respectively. This suggests that named populations experience this benefit less than the typical PSE customer.

Figure K-17: Net Metering Installations



Distribution Redundancy

One measure of resilience is how flexible the grid is in responding to a wide array of disruptive events or disasters, such as wind storms, wildfires and earthquakes. An interconnected grid with multiple paths available to serve customers can restore power to customers more quickly during interruption events by re-routing power through alternate feeds. This may be from an adjacent distribution or transmission line being served by the bulk electric system or via a local microgrid when the larger system is not available.

The initial evaluation of this flexibility in PSE's territory focused on reviewing the alternate paths available to serve customers based on existing data that only identified whether an alternate path existed. The results show that most areas in PSE's territory have similar levels of this type of flexibility, but more information and analysis are needed to determine whether this is a useful measure of resiliency since all available switching points do not provide the same level of backup capacity to customers. In many cases, limiting factors, such as circuit topology or loading limits, reduce the number of circumstances under which an alternate path is useful. Identifying and quantifying these and other limitations is difficult and further analysis is needed.

Note that having multiple paths for routing power to customers is likely just one of many potential system characteristics that may help to define resiliency. Further work and a broader discussion is needed to determine the value of this type of resiliency as well as what other characteristics provide value and should be included in a resiliency analysis.

Distribution Automation

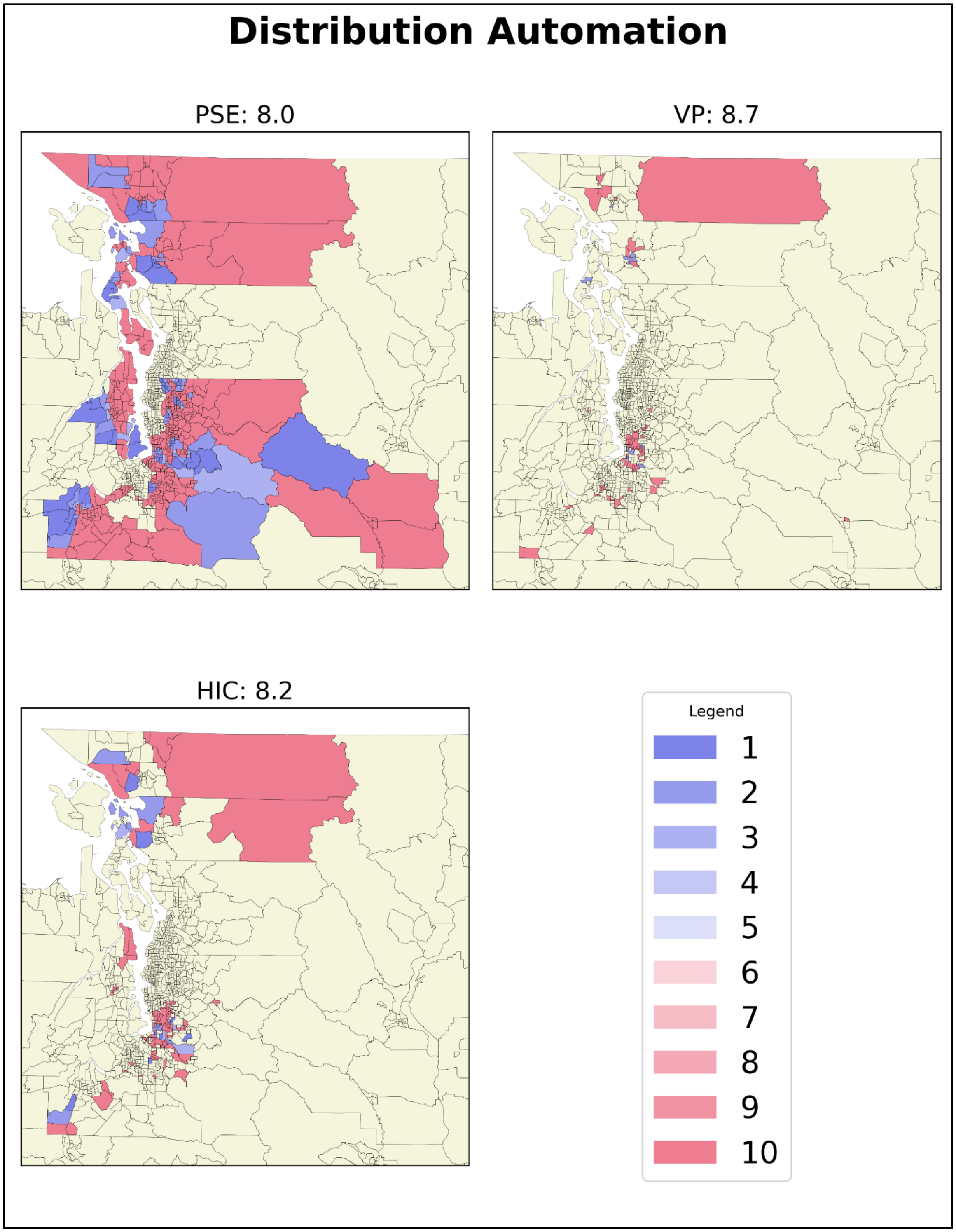
Figure K-19 shows the disparity score results for distribution automation. Distribution automation is a measure of the percent of linear miles of distribution circuits in a given census tract which are equipped with distribution automation devices such as Fault Location, Isolation and Self Restoration (FLISR) equipment. Distribution automation allows for minimization of service interruptions for affected customers and faster response times to interruptions by re-routing power to customers through alternate feeds, some of which may be served by microgrids. Distribution automation is an indicator for energy resiliency, as greater automation improves PSE's ability to recover from interruptions. Distribution automation is modeled as a customer benefit, therefore lower scores correspond to greater benefits and higher scores with reduced benefit.

Distribution automation data was only available for PSE's service area; therefore, it is not possible to compare scores to the average Washingtonian. The typical PSE customer has a disparity score of 8.0, which falls outside of the expected range of 5 to 6. Since the typical PSE customer has a disparity score greater than the expected average range of 5 to 6, it means that PSE's service territory has a low degree of automation. This is reflected in the data, as 75 percent of PSE census tracts have no distribution automation.

Vulnerable populations and highly impacted communities have disparity scores higher than to the typical PSE costumer of 8.7 and 8.2, respectively. This suggests that named populations experience this benefit less than the typical PSE customer.

Distribution automation is one of many possible indicators of energy resiliency. PSE is actively working both internally and with industry partners to develop more fitting measures of energy resiliency. Beyond distribution automation, PSE is actively exploring other technologies and initiatives to improve resiliency such as microgrids. Microgrids are geographic areas with a self-sufficient energy supply. Microgrids do not rely on the larger grid for power in times of need and therefore greatly increase the resiliency of structures located within the microgrid. Microgrids incorporating key facilities such as hospitals, emergency response facilities and governance facilities could help reduce burdens from high impact, low frequency power interruptions.

Figure K-19: Distribution Automation



Electric Vehicle Charge Station Installations

Figure K-20 shows the disparity score results for PSE customers who have installed electric vehicle (EV) charging stations at their homes. EV charging stations are installed voluntarily, at the customer's expense. Data for EV charging stations were obtained from PSE records. EV charging station installations are modeled as a customer benefit, therefore lower scores correspond to higher program enrollment and higher scores with lower program enrollment.

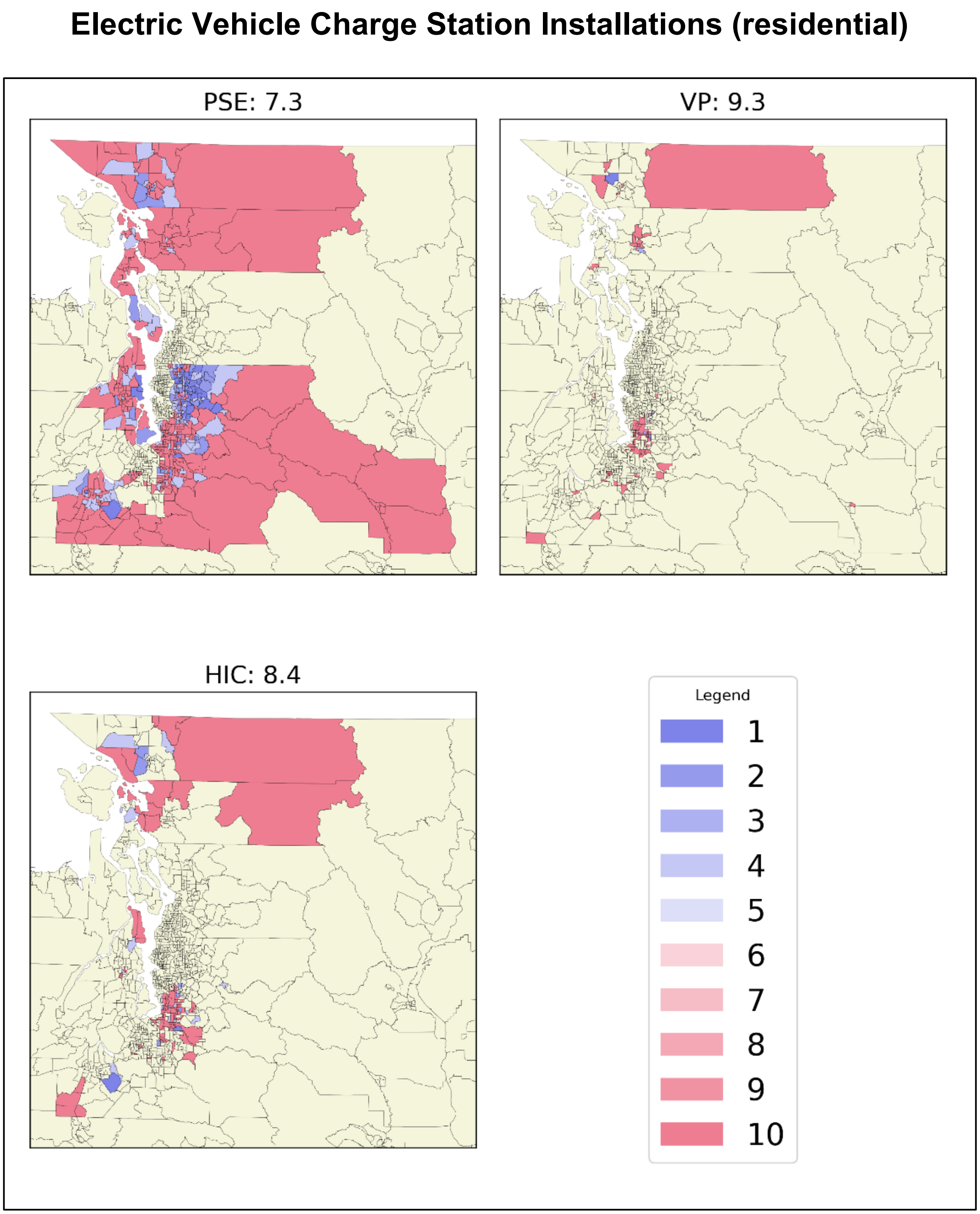
EV charging station installations are an indicator of EV adoption rates across PSE's service territory. This is a rudimentary measure of EV adoption, as not all EV owners will install a charging station. EV adoption may be associated with a decrease in burdens such as air quality impacts and noise pollution. However, tracking specific reductions in these burdens is difficult, since electric vehicles are mobile and will move between communities. EV charging stations provide a reasonable proxy for where EVs may drive the most, as drivers tend to drive most around their homes and communities.[16]

Individual customer data was aggregated at the census tract level. EV charging station installation data was only available for PSE customers, therefore it is not possible to compare scores to the average Washingtonian. The typical PSE customer has a disparity score of 7.3, which falls outside of the expected range of 5 to 6. This shows a significant bias in the data toward a higher disparity (i.e., fewer EV charging station installations). This is expected, since EVs are a newer technology and adoption rates are still relatively low. It is fair to say that the typical consumer does not own an EV, and the results reflect this reality.

Vulnerable populations and highly impacted communities have significantly higher disparity scores than the typical PSE costumer at 9.3 and 8.4, respectively. This suggests that named populations experience this benefit much less than the typical PSE customer.

16 / https://www.bts.gov/statistical-products/surveys/national-household-travel-survey-daily-travel-quick-facts

Figure K-20: Residential Electric Vehicle Charge Station Installations



4. EHEB ASSESSMENT FUTURE WORK

PSE put a great deal of thought and effort into developing a methodical and robust framework to assessing disparities across PSE's service area. However, PSE acknowledges that there is still a great deal of work to be done. PSE received valuable feedback from stakeholders on opportunities for improvement. Next steps for continued development of the EHEB Assessment are outlined below.

- **Geographic vs Demographic Assessment.** PSE elected to perform a geographic assessment for the named population portion of the assessment. It was brought to PSE's attention that it may add value by continuing to assess highly impacted communities using the geographic framework, but to shift the vulnerable population assessment to a demographic framework. PSE believes the different perspective of incorporating a demographic framework for assessing impacts to vulnerable populations will add new insights to the EHEB Assessment.
- **Average vs Binary Criteria.** PSE elected to select vulnerable populations based on an overall average of several vulnerability criteria. It was suggested that PSE select vulnerable populations based on a binary select process whereby, if the community qualifies for any single vulnerability criteria that community would be designated a vulnerable population, regardless of the scores for other criteria. PSE believes enacting this change would result in a more inclusive definition of vulnerable populations and would add value to the assessment, particularly accompanied with inclusion of a demographic framework discussed above.
- **Customer Benefit Indicator Selection.** PSE developed an initial list of customer benefit indicators for use in the EHEB Assessment. These indicators were developed largely through an internal process and vetted through stakeholder engagement during IRP meetings. However, PSE recognizes that much more customer input and engagement is needed to refine the customer benefit indicators. PSE will continue to revise and refine the customer benefit indicators through the CEIP public participation process and consultation with the Equity Advisory Group. Furthermore, PSE received feedback that customer benefit indicators should be outcome-based, as opposed to modeling of specific programs or actions. PSE will engage stakeholders in developing outcome-based customer benefit indicators.
- **Customer Benefit Indicator Development.** In addition to the customer benefit indicator selection discussed above, PSE is also in the process of developing and refining its understanding of customer benefit indicators. Indicators that inform areas such as energy security and resiliency require development of new measures and data sets to better understand disparities of named populations. As these new measures and data sets are established, vetted and informed through public participation, they will be added to the Assessment.
- **Data Resolution.** PSE selected the census tract as the default geospatial resolution for the EHEB Assessment. Stakeholders recommended investigating higher data resolutions such as customer-level data or census block level-data. PSE will investigate incorporation of higher data resolution into future iterations of the EHEB Assessment.

L Temperature Trend Study

The Temperature Trend Study was developed by Itron as one of the options of future temperature assumptions for the temperature sensitivity described in Chapter 6, Demand Forecasts. The temperature sensitivity is a way to begin to evaluate the impacts of climate change. Further details are provided in Chapters 7 and 8.

Knowledge to Shape Your Future

Electric | Gas | Water
information collection, analysis and application

Puget Sound Energy Temperature Trend Study

Submitted to:

Puget Sound Energy

Submitted by:

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Suite 428
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November 2020

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Puget Sound Temperature Trend Study

1. Overview

Over the last twenty years, there has been a growing concern about the impact of climate change on the environment, the economy, and long-term human health. It has been well-documented that the air mass and oceans are warming, contributing to more extreme weather events, and by extension, potentially catastrophic weather events in the future. In the Northwest, the Bonneville Power Authority (BPA), the Army Corps of Engineers, and the Bureau of Reclamation (*River Management Joint Operating Committee – RMJOC*) have been studying climate impact on the Columbia River Basin since 2009. The RMJOC studies, like climate-model-based studies across the country, project increasing temperatures. The Northwest Power and Conservation Council (NWPCC) has been building on this work as part of the 2021 Power Plan; updated climate scenarios based on the RMJOC analysis will be incorporated into long-term energy and demand forecasts.

Itron was contracted by Puget Sound Energy (PSE) to evaluate temperature trends in the PSE service area. Rather than basing analysis and projections on Global General Circulation Models (sometimes referred to as Global Climate Models - GCM), we have taken a data-driven approach based on historical temperature trends. Trend-based projections provide a comparison against the wide-range of temperature outcomes derived from GCM models and provide a basis for developing weather inputs for sales, energy, and peak forecast models. Itron has performed similar analyses for NVEnergy and NYISO (New York Independent System Operator). The focus on temperature trends, rather than complex interactions in climate, provides a simple, data-driven approach for analyzing and evaluating the impacts on electricity and natural gas consumption.

The primary objectives include:

- Evaluating historical temperature trends observed in PSE's service area
- Developing estimates of future temperature trends based on results of the historical temperature analysis
- Translating temperature projections into long-term Heating Degree Days (HDD) and Cooling Degree Days (CDD) used for PSE's load forecasting models
- Comparing PSE's observed temperature trends to recent regional and other climate impact studies

The focus of this work is on temperature trends. It is not a climate study. The analysis does not address other components of weather and climate, such as precipitation, snowpack, extreme weather events, or El Niño/La Niña events.

2. Summary

Our analysis shows that there is a strong and statistically significant increase in average temperature in the PSE service area. Temperatures at the Seattle-Tacoma International Airport (SEA-TAC) have been steadily increasing over the last fifty years. Itron's analysis of long-term temperature trends shows temperature increasing approximately 0.04 degrees per year or 0.4 degrees per decade. This trend is consistent with other analyses of historical temperature trends and recent Colombia River Basin climate impact study. Forecasts based on the average of past temperatures are likely to underestimate future cooling requirements and overestimate heating requirements.

While PSE average daily temperatures are increasing, peak-day temperature trends are statistically weak, but still positive. We are still likely to experience extreme cold-days consistent with the past and summer peak days that are not significantly warmer than they are today.

3. Climate Impact Studies

Increasing global temperatures have been well-documented. The majority of climatologist attribute temperature increases to a rise in anthropogenic (i.e., caused by humans) greenhouse gas concentrations.

The Intergovernmental Panel on Climate Change (IPCC), the world's leading organization on climate change, in their most recent temperature projections show that by 2100, global average temperatures increase 1.1 to 2.6 degrees Celsius for RCP 4.5 and 2.6 to 4.8 degrees Celsius for RCP 8.5 over the base-year period (1986 – 2005); this translates into roughly 0.5 to 0.9 degree (Fahrenheit) increase per decade (*Appendix A, Reference 1*).

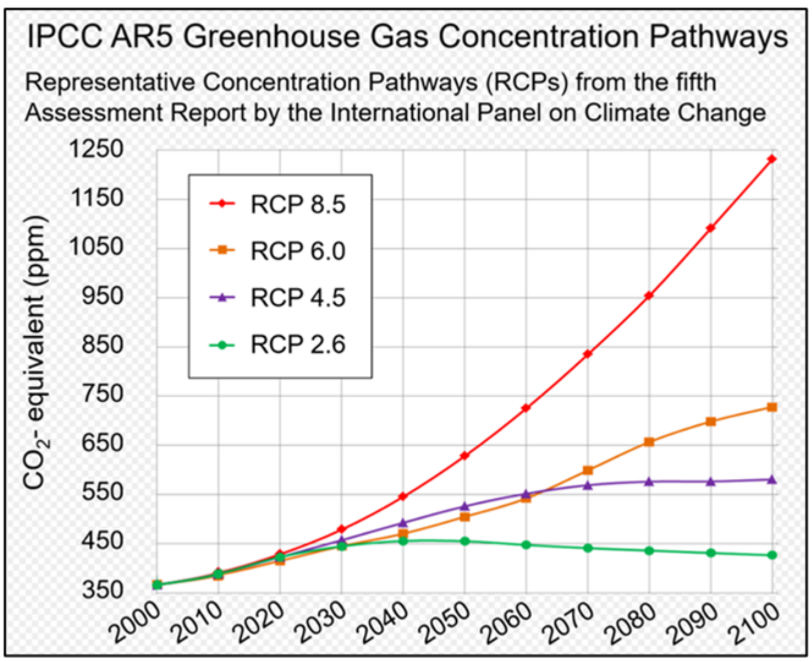
The River Management Joint Operating Committee (RMJOC) began studying the impact of climate change on the Columbia River Basin in 2009. The RMJOC includes Bonneville Power Administration, United States Army Corps of Engineers, and United States Bureau of Reclamation. The 2009 – 2011 analysis indicated that there was a strong likelihood of increasing temperatures due to anthropogenic causes. In 2013, RMJOC began work to update the study. The updated analysis and associated water flow data set was published in June 2018 (*Appendix A, Reference 2*). The focus of the study was on the potential impact of climate change on the Federal Columbia River Basin Power System. RMJOC concluded increasing greenhouse gases will result in increasing temperatures that in turn will contribute to declining snowpack, more of the winter runoff in the form of rain, earlier spring runoffs, lower water levels in the summer months, and greater difficulty managing the river system. The study further concluded there will be a decrease in regional heating requirements (3% to 4% in December) and an increase in cooling loads (1% to 3% in July). Depending on future greenhouse gas paths, temperatures are expected to increase 0.3 to 1.0 degrees per decade between 2010 and 2040 (*Appendix A reference 1*).

NWPCC, which is responsible for regional power planning in the Pacific Northwest, is currently working on the 2021 Power Plan. Updated climate scenarios based on the RMJOC climate modeling work were presented in April 2020. Results indicate fewer heating degree-days (HDD) and more cooling degree-days (CDD), both of which are consistent with increasing temperatures.

The basis for climate projections in the RMJOC, the NWPCC, and other climate projections are derived from Global Climate Models (GCM). There are over fifty GCMs that model the interaction between greenhouse gas, the physical environment, and solar radiation. Over the last ten years, there have been significant improvements in understanding the complex relationship between increasing greenhouse gases, air circulation, oceans and ocean currents, land and its topography, vegetation, and human activity, as a result of increased computing power, advances in data collection, and improvements in modeling. This has allowed climatologists to develop more confidence around localized climate impact results.

GCM model outputs are based on one of four greenhouse gas paths established by the IPCC. The paths reflect the greenhouse gas accumulation to reach specific Radiative Forcing (RF) levels by the year 2100. Figure 1 shows these paths.

Figure 1: GCM Greenhouse Gas Paths



RF is a measure of the difference between insolation (the amount of heat the earth absorbs from the sun) and the amount of heat released back to space. In 1750, the RF value was 0. Estimated 2018 RF value is 3.1. Most climate impact studies focus on the RF 4.5 and RF 8.5 paths. Many climatologist and studies (including the RMJOC) believe we are on the 8.5 path. Other climatologists believe that the 4.5 path is the more likely outcome. Currently, there is little divergence in these paths. Very few expect the 2.6 path, as that would imply an aggressive worldwide greenhouse gas mitigation effort. There should be a better idea as to which path we are on over the next ten years.

Each model and selected greenhouse gas path generates a different temperature path based on the underlying model structure and model inputs. Given differences in models, model inputs, and greenhouse gas path assumptions, there is a large range of possible temperature outcomes. In developing temperature and other climate variable projections, climate studies will weigh the regional output from multiple models; for the NWPCC this involved utilizing an ensemble approach across 19 GCM. References to recent climate impact studies and projected temperature trends are provided in Appendix A.

Rather than basing temperature and degree-day projections on GCM results, this study bases CDD and HDD projections on historical temperature trends. The advantage of a data-driven approach is that we can calibrate into specific regional weather data and statistically measure both trend and variance. Regional global climate modeling work provides a framework to compare against trend-based temperature projects.

4. PSE Temperature Analysis

The primary objective of this study is to estimate temperature trends for the PSE service area and to develop normal heating degree-days (HDD) and cooling degree-days (CDD) that reflect estimated temperature trends. Temperatures in the PSE service area are increasing approximately 0.4 degrees per decade. With increasing temperatures, HDDs can be expected to decline and CDDs to increase.

Our approach was developed as part of the climate impact study conducted for the New York ISO. The study estimated temperature trends for over twenty-weather stations across the state with simple linear trend regression models. Temperature trend coefficients derived from the regression equations were used in calculating regional trended normal heating and cooling degree-days. Daily, monthly, and peak degrees were then used in estimating long-term end-use load models and developing long-term hourly load forecasts for each of the New York ISO planning zones (*Appendix A, Reference 3*).

Estimate Temperature Trends

The PSE temperature analysis is based on reported temperatures for the Seattle-Tacoma International Airport (SEA-TAC) for the period 1950 through 2019. Annual average, maximum, and minimum temperatures are calculated from the historical hourly temperature data. While we evaluated a number of temperature concepts, we ultimately focused on:

- Average annual temperature
- Minimum temperature during peak winter heating period
- Maximum temperature during peak summer cooling period

Average Annual Temperature. Temperature trends are estimated using simple linear regression models that relate temperature to time as measured by a linear trend variable.

Figure 2 shows the calculated average temperature trend and coefficient statistics. The light-blue line shows the 90% confidence interval. The model is estimated with annual average temperature starting in 1950.

Figure 2: Average Annual Temperature Trend

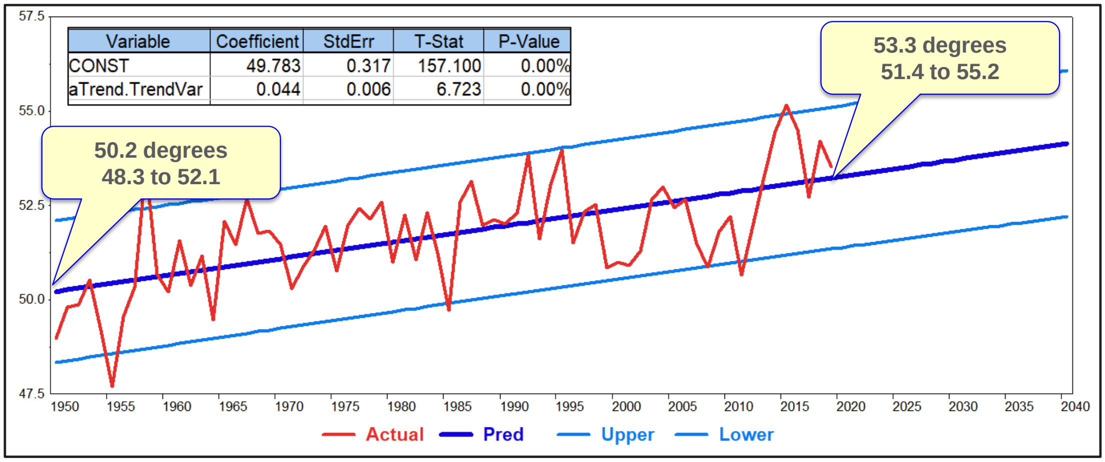


Figure 2 shows a positive and statistically significant temperature trend with a T-Statistic of 6.7 and a P-Value of 0.0%. The estimated trend coefficient is 0.044; this implies that over the estimation period, average temperatures have been increasing 0.044 degrees per year or 0.44 degrees per decade. Given the model standard error, at the 90% confidence level, temperatures have been increasing 0.34 to 0.54 degrees per decade. The expected temperature in 1950 was 50.2 degrees compared with 53.2 degrees in 2019. Expected average temperature increased 3 degrees over this period.

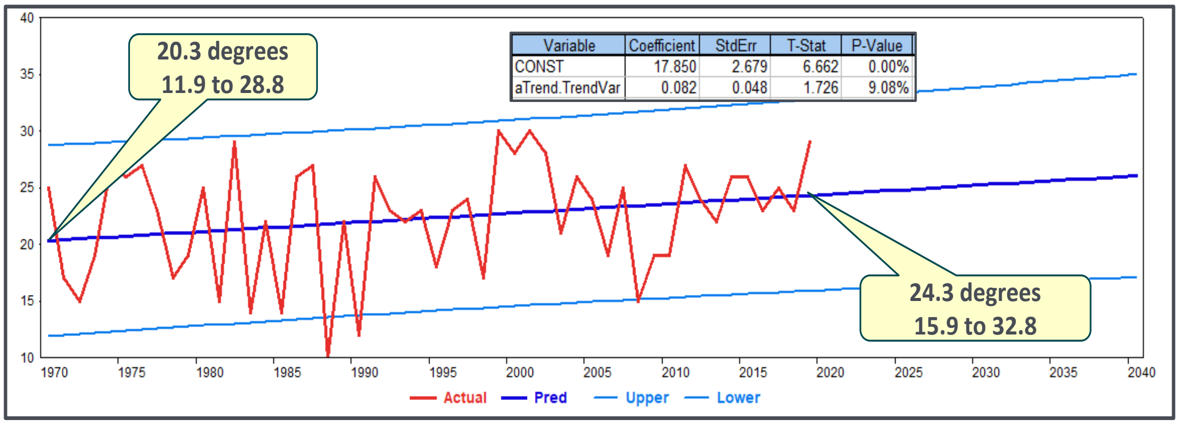
In the New York study, there was some discussion as to whether the temperature trend was linear or in-fact increasing at a faster rate over time. We evaluated a number of functional forms, but in the end, concluded that temperatures are best explained by a linear trend. This is also the case with PSE; there is no indication that changes in temperature are accelerating.

Over the last seventy years, temperature measurement has been impacted by changes in measurement location and measuring equipment (e.g., transitioning from analog to digital measurement). Shortening the estimation period to 1970 (i.e., 50 years) results in 0.037 degrees per year (0.37 degrees per decade). Depending on the start year, the estimated trend coefficients vary from 0.33 to 0.47; all within the 90% confidence interval. The average across the different estimation periods is approximately 0.4 degrees per decade.

The impact of increasing temperatures on energy demand largely depends on the sensitivity of electricity or natural gas use to changes in temperature. PSE is a winter-peaking utility with significant electric and natural gas heating load; winter energy requirements are strongly correlated with winter temperatures. The relationship of summer loads and temperatures are relatively weak given low cooling load requirements due to generally mild summer temperatures. Increasing temperatures will have a stronger impact on the heating side in the form of decreasing HDD while increasing CDD are likely to have only a small impact on cooling-related energy use. As a result of increasing temperatures, HDD can be expected to decline on average 0.5% per year; ultimate impact on sales will depend on customer-class size and usage-sensitivity to changes in HDD.

Winter Heating Peak Temperature. PSE is most concerned with minimum temperature trends as it is cold-day temperatures that drive heating requirements and system peak. PSE uses minimum temperatures for hours 8 to 21 for the heating season (November to February) to define the peak temperature. Figure 3 shows the minimum winter temperature trend for the hours when peaks can occur.

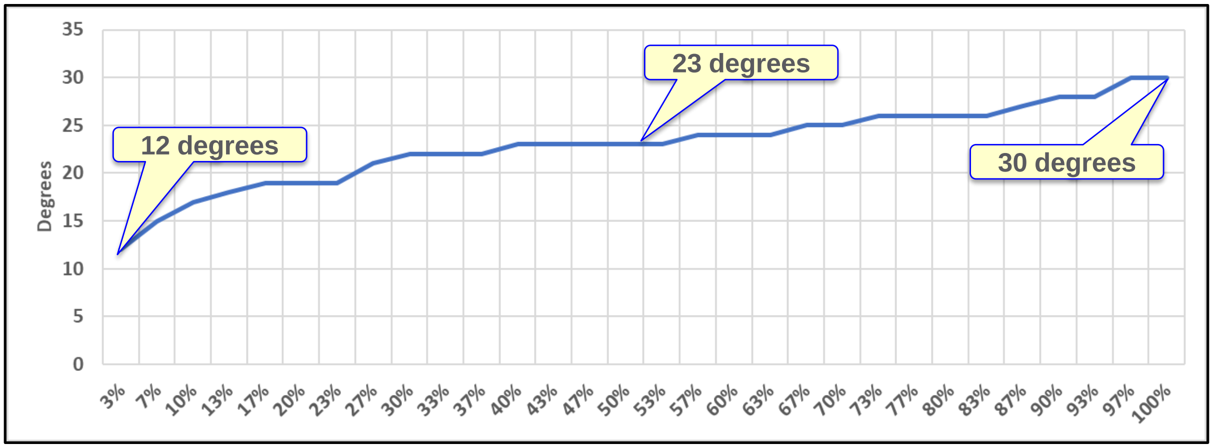
Figure 3: Winter Peak Temperature Trend



Starting estimation from 1970, the winter peak temperature is increasing 0.082 degrees per year or 0.82 degrees per decade. While this is faster than average temperature, the standard error is significantly larger, resulting in a relatively large 90% confidence interval around the minimum temperature trend. The expected minimum temperature in 1970 of 20.3 degrees is still within the 2020 90% confidence interval. This has implications when considering the appropriate assumptions for modeling peak-day weather impacts.

PSE electric system demand peaks in the winter period. The peak demand is largely driven by peak-day minimum temperatures. PSE currently plans for an expected peak-day temperature of 23 degrees. The 23-degree design day is based on the minimum winter temperature that occurred in each of the last 30-years. This is depicted in Figure 4 **Error! Reference source not found.**.

Figure 4: Winter Minimum Peak-Day Temperature (30-years, ranked low to high)

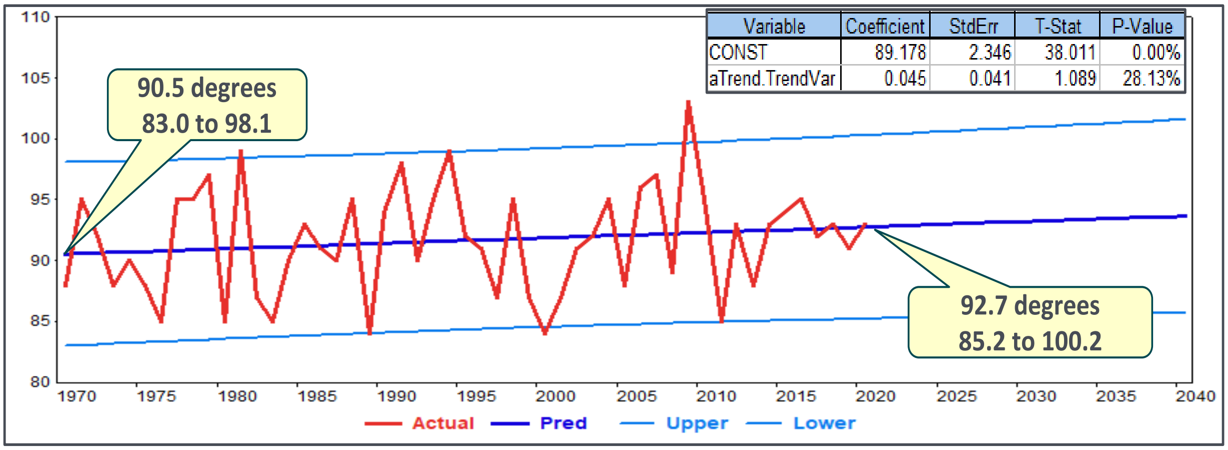


The coldest temperature in each year is ranked from the lowest temperature (12 degrees) to the highest minimum temperature (30 degrees). PSE plans system peak for the median of the data series -- 23 degrees, which is also the mean for this data series, as well as the mode, with 5 out of the last 30 years experiencing a day where minimum temperature fell to 23 degrees.

Based on the minimum temperature trend model, the expected minimum winter temperature in 2019 is 24.4 degrees with a 90% confidence interval of 16.4 degrees to 32.4 degrees. The current 23 degree-design temperature falls well within this range. Given the large number of occurrences where this temperature actually occurred, it is appropriate to plan for a 23 degree minimum temperature day even as minimum temperatures continue to rise. Calculating winter peak-day normal weather conditions based on the prior thirty years is a reasonable approach.

Summer Cooling Peak Temperature. The summer peak temperature is defined as the highest temperature over the summer cooling hours. This includes hours 8:00 to 20:00 for the months July and August. Figure 5 shows the summer maximum temperature trend starting in 1970 for the hours when peak occurs.

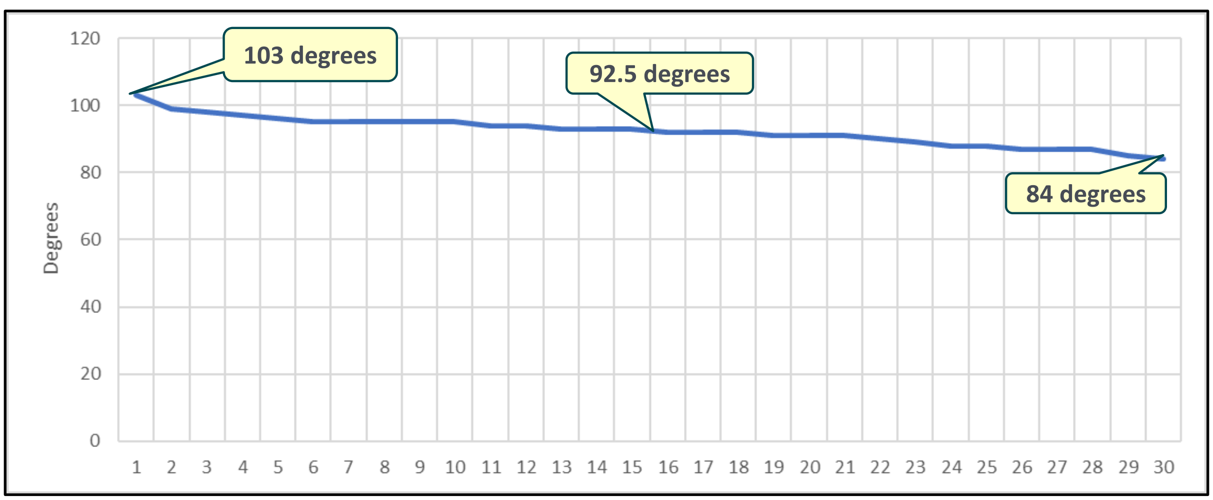
Figure 5: Summer Peak Temperature Trend



While the summer maximum temperature trend is positive at 0.45 degrees per decade, it is statistically significant only at the 70% level of confidence. For PSE, these translates into a wide expected summer peak temperature range with a 90% confidence bound of 85.2 to 100.2 degrees in 2020.

Figure 6 shows the peak-day temperature for the summer months (July through August). Temperatures are ranked from the highest peak-day temperature (103 degrees) to the lowest annual peak-day temperature (84 degrees).

Figure 6: Summer Peak-Day Temperature (30-years, ranked high to low)



The summer peak demand design temperature is defined as the median summer peak-day temperature (the midpoint of the temperature curve). The median temperature for the last 30 years is 92.5 degrees. As discussed above, the summer peak temperature trend is statistically weak and as a result there is a wide 90% confidence interval around the temperature trend line. The expected temperature based on the summer peak temperature trend line is 92.7 degrees with a minimum expected temperature of 85.2 degrees and a maximum expected temperature of 100.2 degrees. The 92.5 design temperature falls within the 90% confidence interval. Even as far out as 2040, the summer design temperature is well within the 90% confidence interval.

Temperature Trend Comparisons

In addition to New York, we have evaluated temperature trends for several utility service areas across the country, with estimated average temperature trends varying from 0.4 to 1.0 degrees per decade. In all cases, the average temperature trend is statistically significant. A recent study by the Penn Institute for Economic Research (PIER) found similar results (*Appendix A, Reference 4*). Table 1 shows average degree-day per decade derived from the PIER study.

Table 1: Estimated Temperature Trends

City	Station	TempChg	Per Decade
Atlanta	ATL	4.36	0.76
Boston	BOS	2.06	0.36
Baltimore	BWI	2.25	0.39
Cincinnati	CVG	2.53	0.44
Dallas-Fort Worth	DFW	3.44	0.60
Des Moines	DSM	3.93	0.69
Detroit	DTW	4.09	0.72
Las Vegas	LAS	6.05	1.06
New York (LGA)	LGA	4.03	0.71
Minneapolis	MSP	4.72	0.83
Chicago	ORD	2.86	0.50
Portland	PDX	2.55	0.45
Philadelphia	PHL	4.78	0.84
Salt Lake City	SLC	3.92	0.69
Tucson	TUS	4.89	0.86
Median		**3.93**	**0.69**

The median temperature trend across the 15 cities evaluated is 0.7 degrees per decade. Temperature trends varied from 0.36 degrees (Boston) to 1.06 degrees (Las Vegas). The highlighted cities show temperature trends close to what was estimated for the PSE service area. Like Seattle-Tacoma, these cities are in close proximity to the ocean, where temperature increases have tended to be lower.

While the PIER study measured average temperature trend, the primary focus was the diurnal temperature range (DTR); the DTR is the difference between the maximum and minimum temperature; the PIER study found a statistically significant decline in DTR across the sample cities. Other earlier work showed decline in DTR is largely the result of nighttime low temperatures increasing faster than daytime high temperatures.

Summary. The average temperature has been showing a strong statistical increase over the last fifty years in the PSE service area and across the country. PSE winter heating peak temperature is increasing faster than average PSE temperature, though there is a larger variance in expected minimum temperatures when evaluated for the 90% confidence interval.

While the summer cooling peak temperature is increasing, the trend is statistically weak. In other studies, we have found similar results where there has generally been a small positive maximum temperature trend, but the trend is statistically weak. Evidence from the PIER study and our analysis of other service areas indicate that it is largely increased in overnight minimum temperatures that are contributing to long-term overall temperature increase.

5. Translating Temperature Trends to Degree-Days

Electric and natural gas sales are significantly impacted by heating and cooling requirements. In electric and natural gas load modeling, the weather impact is generally captured by heating degree-days (HDD) and cooling degree-days (CDD). Actual HDD and CDD are key variables in usage models with expected HDD and CDD used in projecting future demand and isolating weather-related sales for variance analysis. HDD are designed to capture heating requirements and CDD cooling requirements. HDD and CDD are often referred to as spline variables as they only take on a positive value when a specified condition is met. For example, HDD with a 65 degree temperature base, only takes on a positive value when the average temperature is ***below*** 65 degrees. If the average daily temperature is 50, then HDD is 15 (i.e., 65 degrees – 50 degrees = 15); if the temperature is 65 or greater HDD equals 0. CDDs are the opposite; CDD have a positive value when temperatures ***exceed*** a defined reference temperature. For a CDD with a 65-degree reference point, a day with average temperature of 70 degrees results in a CDD of 5 (70 degrees – 65 degrees = 5); if the temperature is 65 degrees or lower CDD equals 0.

The following are the formulas for CDD and HDD, both with a base temperature of 65 degrees:

$$CDD65_d = Max(T_d - 65, 0)$$
$$HDD65_d = Max(65 - T_d, 0)$$

Where:

T = Average Daily Temperature
d = Date

Calculating Normal Degree Days. Normal HDD and CDD reflect our best expectation of future weather conditions and associated heating and cooling energy requirements. Normal degree-days also provide the basis for evaluating the weather impact on current electricity and natural gas sales. Normal HDD and CDD are calculated as an average of past weather conditions; we assume that the best estimate for future weather conditions is an average of past conditions. The industry standard has been to derive normal degree days using a 30-year historical period. Many utilities have moved to a 20-year and even 10-year normal period in recognition that temperatures are increasing; the shorter estimation period gives more weight to the current, warmer temperatures.

PSE calculates normal weather using the most current 30-year period. The current period is 1990 to 2019. PSE captures some of the increasing temperatures over time as the 30-year period is updated each year.

PSE uses a standard approach for calculating normal HDD and CDD for a range of temperature breakpoints. PSE first calculates daily HDD and CDD from historical daily average temperatures. The daily degree days are then averaged by date (i.e., average all the January 1st values, average all the January 2nd values, ..., average all the December 31st values) across the 30 years of historical weather data. The result is an average (or normal) daily degree-day series (366 values, including leap-year) for each temperature breakpoint concept. The normal daily degree-days are summed to derive calendar-month and annual normal HDD and CDD. Daily normal degree-days that reflect the billing period are derived by combining the meter read schedule and daily normal degree-days.

Table 2 shows calculated calendar-month and annual normal degree-days for different temperature breakpoints.

Table 2: PSE Normal Degree-Days (1990 -2019)

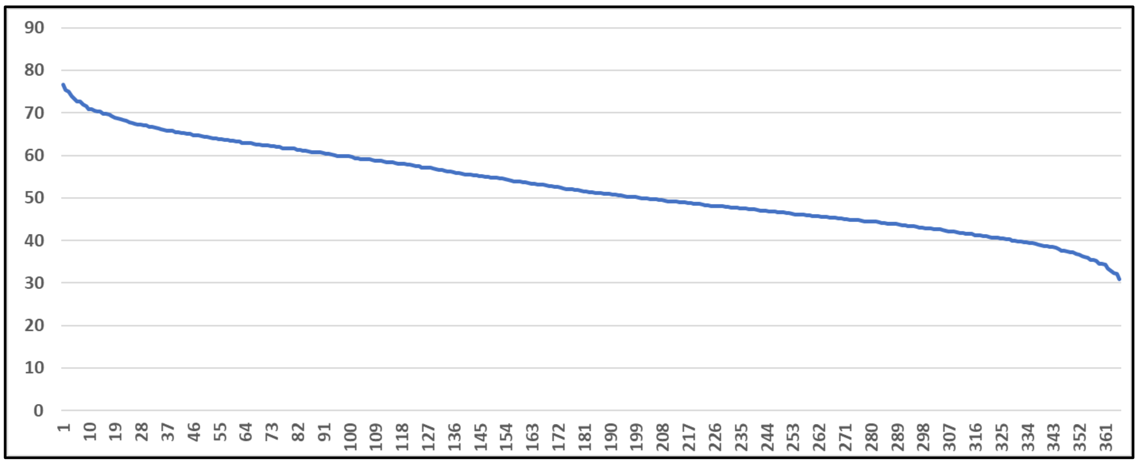
Month	HDD55	HDD60	HDD65	CDD60	CDD65
Jan	404.3	559.3	714.3	-	-
Feb	348.8	493.8	638.8	-	-
Mar	279.2	432.2	586.7	0.6	0.2
Apr	165.5	303.2	450.2	3.7	0.7
May	53.8	153.6	287.2	28.2	6.9
Jun	7.6	54.9	159.9	70.8	25.7
Jul	0.1	6.8	53.8	186.5	78.5
Aug	-	3.5	44.7	185.4	71.6
Sep	4.0	40.0	135.2	71.5	16.8
Oct	101.4	236.3	389.5	1.8	-
Nov	282.4	430.7	580.6	0.0	-
Dec	434.0	588.8	743.8	-	-
Total	**2,081.2**	**3,303.0**	**4,784.8**	**548.5**	**200.3**

Based-on the most recent 30 years, there are 2,081 normal HDD with a 55 degree-day base and 200 CDD with a 65 degree-day base. As summer weather conditions are mild in the PSE service territory, there are relatively few CDD.

Since temperatures have been increasing, the 30-year average is more representative of 2005 weather conditions (i.e., the mid-point of the 30-year normal estimation period) than 2019 weather conditions. By 2019, we would expect to see fewer HDD and more CDD than those derived from the 30-year average.

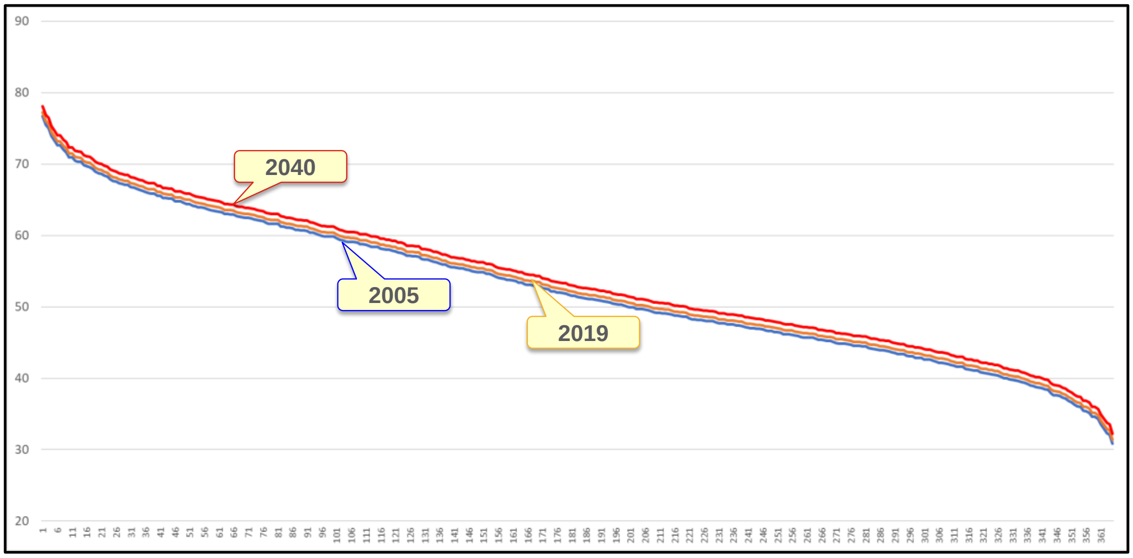
Calculating Trended-Normal Degree-Days. Trended normal HDD and CDD are derived for the PSE 0.4 degree/decade average temperature trend. The process starts with a 30-year average daily temperature series (366 observations) for the same 30-year period (1990 to 2019). Normal HDD and CDD are derived from average temperature (as opposed to daily degree-days) in order to calculate the impact of the temperature trend over time. The starting-year normal daily temperatures are derived using rank-and-average by month; in this process daily temperatures are ranked from the highest temperature to the lowest temperature within each month and then averaged across the monthly rankings. This results in an average temperature duration as depicted in Figure 7.

Figure 7: Average Daily Temperature (1990 - 2019)



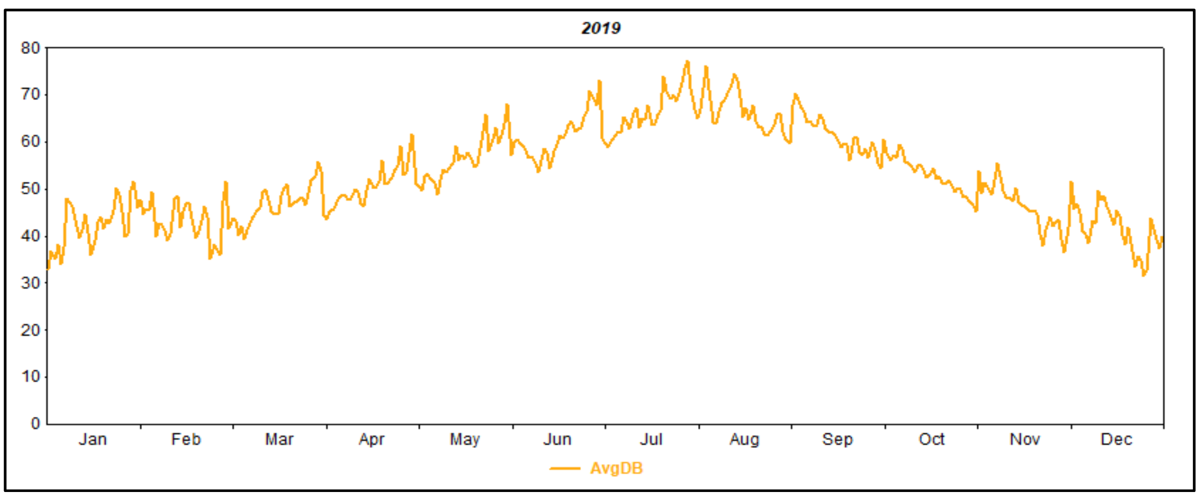
We assume that this curve best represents the average temperature in 2005 (the midpoint of the 30-year period). The normal daily temperature curve is then shifted out 0.04 degrees per year or 0.4 degrees per decade. Figure 8 shows the starting duration curve in 2005, the curve in 2019, and the curve in 2040.

Figure 8: Adjusted Temperature Duration Curves



The normal temperature curves are mapped to a typical calendar-year pattern as depicted in Figure 9.

Figure 9: Normal Daily Temperature Profile (2019)



The normal temperature profiles incorporate the expected temperature trend. The data set is used in generating daily normal degree days. Any aggregation bias (as a result of calculating normal degree-days from normal daily temperatures) is corrected by calibrating the start year (2005) to the PSE 30-year normal degree-days. Figure 10 and Figure 11 show resulting monthly HDD for a 55-degree base and CDD for 65-degree temperature base.

Figure 10: Trended Normal HDD (Base 55 Degrees)

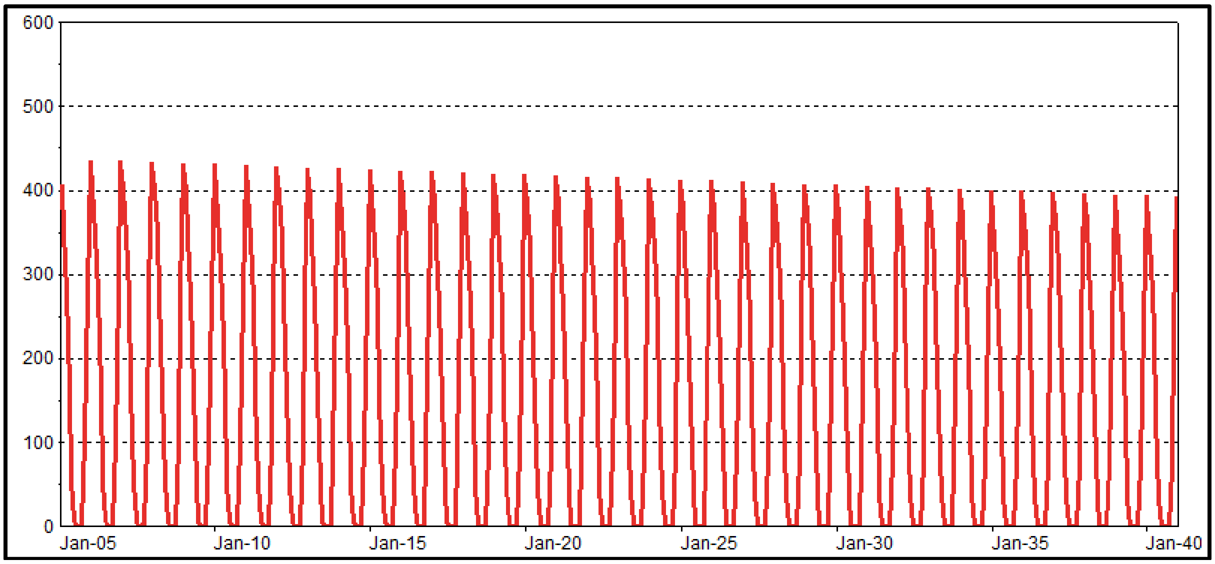


Figure 11: Trended Normal CDD (Base 65 Degrees)

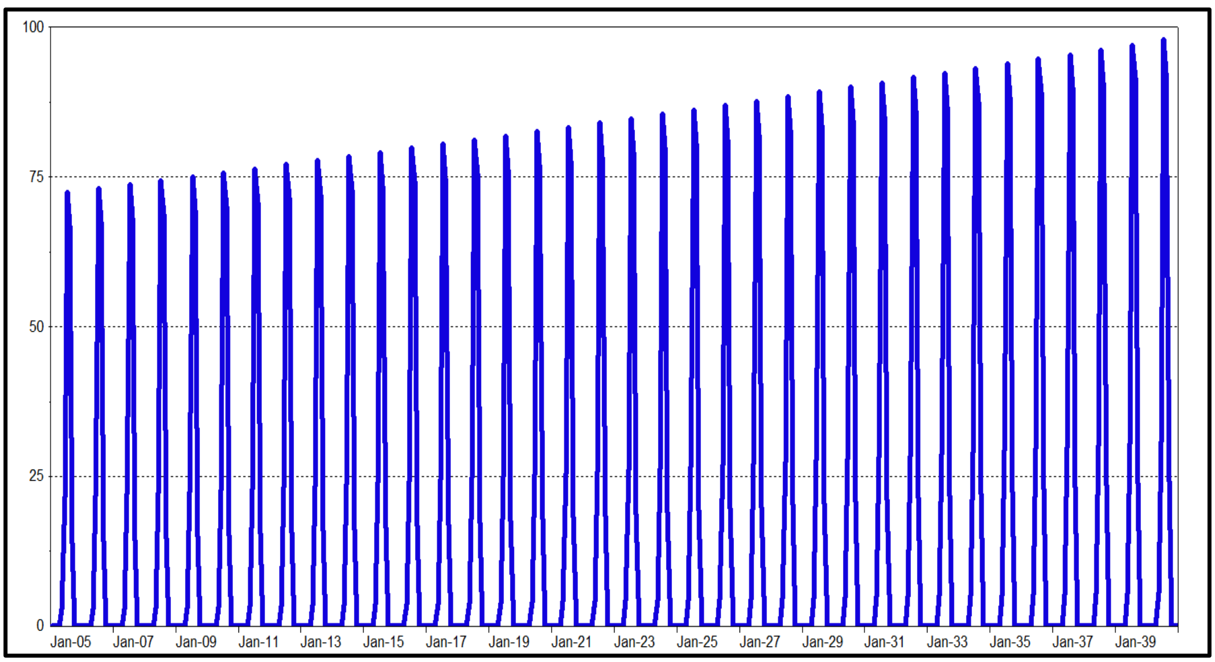


Table 3 shows a comparison of 2020 trended normal degree-days against the 30-year normal.

Table 3: 30-Year Normal and Trended Degree Days

	HDD 55 Degrees		CDD 65 Degrees	
Month	**30-Yr Nrm**	**Trended Nrm**	**30-Yr Nrm**	**Trended Nrm**
Jan	404.3	385.5	-	-
Feb	348.8	336.1	-	-
Mar	279.2	260.8	0.2	-
Apr	165.5	149.4	0.7	-
May	53.8	43.9	6.9	4.0
Jun	7.6	4.6	25.7	25.3
Jul	0.1	-	78.5	82.7
Aug	-	-	71.6	77.0
Sep	4.0	1.7	16.8	17.9
Oct	101.4	87.3	-	-
Nov	282.4	264.5	-	-
Dec	434.0	415.2	-	-
Total	**2,081.2**	**1,948.9**	**200.3**	**206.8**

By 2020 trended HDD with a 55-degree temperature base are 6.4% lower than the thirty-year normal. Assuming average temperatures continue to increase 0.4 degrees per decade, by 2030 the number of HDD are 10% below the 30-year normal and 15% below the 30-year normal by 2040.

While the July trended CDD 65 degree-day base are 5% higher than the 30-year normal and August is 7% higher, the total annual CDD increase is relatively small. May and June trended CDD are slightly lower than the 30-year normal as a result of the normal temperature mapping to the calendar year profile.

6. Conclusions

Electricity and natural gas sales are strongly impacted by weather conditions. Forecasts thus require assumptions of future weather conditions. The traditional approach is to assume that future temperatures will look like the recent past. Long-term energy and demand forecasts are generally based on HDD and CDD derived from averages of historical temperature data. In our most recent benchmark survey, 76 percent of the survey respondents based normal HDD and CDD on 20 to 30-years of historical temperature data. Twelve percent of the respondents based normal temperatures off of 15-years of historical temperature data and 10 percent used ten-years of historical temperature data. PSE currently uses the most recent thirty-year period for calculating normal HDD and CDD.

Utilities are just beginning to evaluate the impact of increasing temperatures on electric and natural gas loads. Our survey shows 12% or respondents are considering $C0_2$ emission targets and 16% are making climate change adjustments. The normal weather survey response is provided in Appendix B.

Data shows that temperatures have been increasing across the country. Average temperatures in the PSE service area have been increasing since at least the 1950s. On average, temperatures are increasing 0.4 degrees per decade. Compared with other regions, this is a relatively slow rate of increase; increases in temperatures are likely lower given PSE/Seattle's proximity to the Pacific Ocean. While average temperature is increasing, the maximum temperature has been relatively muted; as in other regions, it appears most of the average temperature gain is due to increasing minimum temperatures.

Nearly all climate models show temperatures are likely to increase through 2100. Our estimate for PSE service area is close to the RMJOC lower temperature projections based on the RCP4.5 greenhouse gas path. RMJOC, like many organizations, believes that the RCP8.5 path represents "business as usual" and as a result could see significantly higher temperatures that begin to increase at a faster rate than the historical trend. At this point, there is no evidence to support future temperatures will increase at a faster rate. For energy forecasting and weather normalization, it is reasonable to assume that expected HDD will be lower today than thirty-year average HDD, and CDD will be higher than the thirty-year average. Temperatures will likely continue to increase 0.4 degrees per decade; trended-normal HDD and CDD can be estimated to reflect this trend.

While minimum temperatures are increasing, PSE's current method for calculating winter peak-day weather is reasonable. Five of the last 30 years saw years in which the winter minimum temperature fell to 23 degrees. The 23-degree design day is also well within the expected peak-day temperature range. The summer peak-day design temperature is also within the 90% confidence interval. As the 90% summer confidence interval is quite wide, the summer design day temperature is within the 90% confidence interval as far out as 2040.

Appendix A: References

1. IPCC, Long-Term Climate Change: Projections, Commitments, and Irreversibility, 2018. https://www.ipcc.ch/site/assets/uploads/2018/02/WG1AR5_Chapter12_FINAL.pdf

2. Climate and Hydrology Datasets for RMJOC Long-Term Planning Studies: Second Edition (RJOC-II). Part 1: Hydroclimate Projections and Analysis. June 2018. https://www.bpa.gov/p/Generation/Hydro/hydro/cc/RMJOC-II-Report-Part-I.pdf

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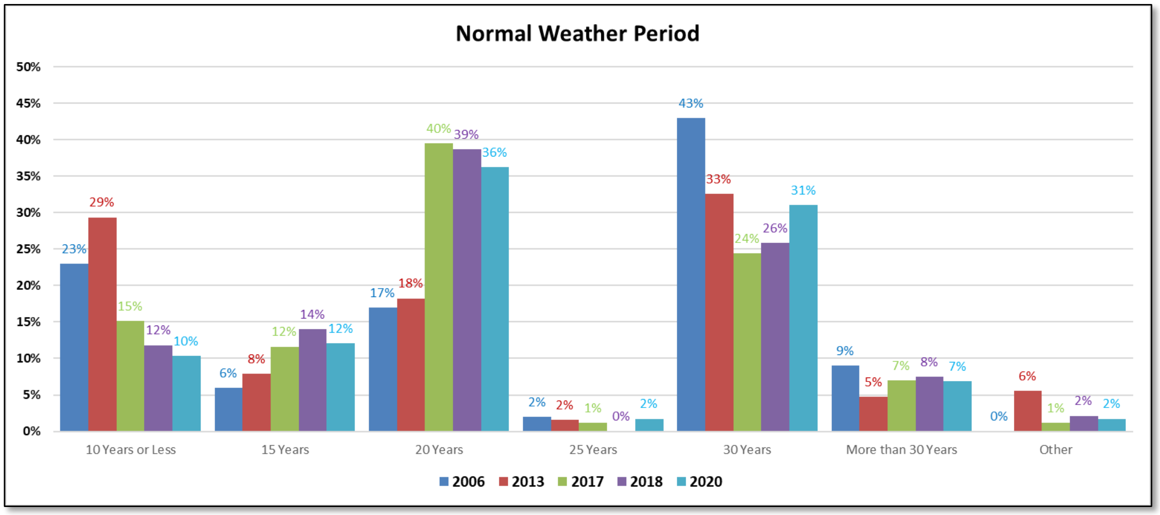
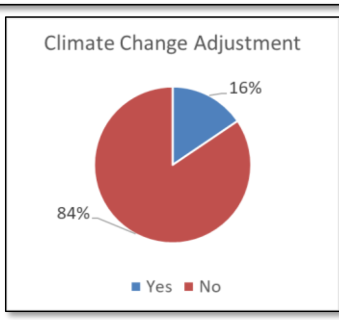
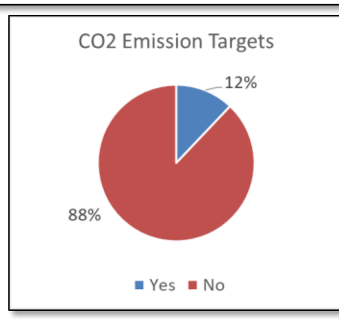
6. The *California Fourth Climate Change Assessment, August, 2018.* http://www.climateassessment.ca.gov

Appendix B: 2020 Itron Benchmark Survey







- 20- and 30-year normal weather are the dominate normal weather periods.
- Few companies recognize climate issues in their forecast.

2021 PSE Integrated Resource Plan

M

Delivery System 10-Year Plan

This appendix presents the 10-year electric and gas PSE-owned delivery infrastructure plans.

Contents

1. OVERVIEW

The PSE electric and natural gas delivery systems are planned to deliver energy through pipes and wires, safely, reliably and on demand; to fully meet all regulatory requirements, including NERC standards that govern the bulk electric system and PHMSA regulations that govern pipeline safety; and to be prepared to meet customers' future energy needs. The systems must be flexible enough to adapt to growing changes in customer uses, include more diverse clean resources, and manage increased complexity.

Modernizing the delivery system is a priority in both plans, as is aligning those plans with resource planning results. This includes a range of key foundational technology investments, specific asset hardening to improve reliability and resiliency to major events, intelligent demand-side management systems to optimize energy use, and backbone major infrastructure improvements.

2. ELECTRIC DELIVERY SYSTEM

Existing Electric Delivery System

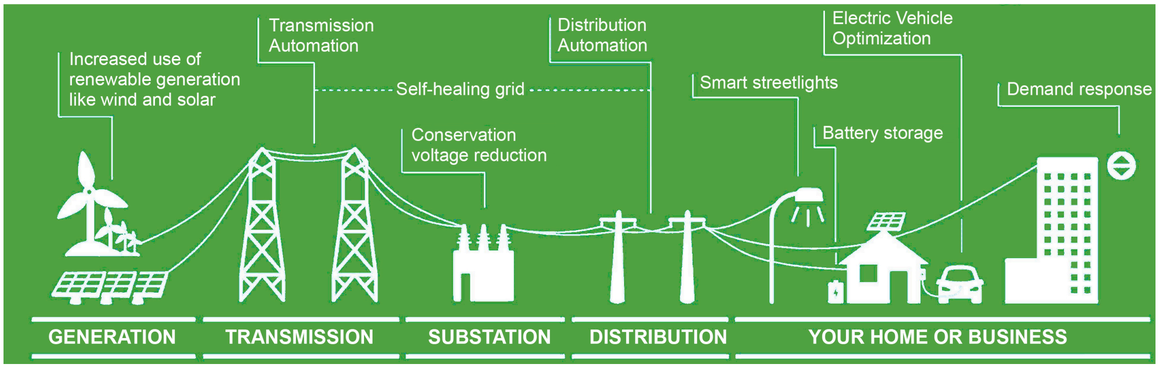
The table below summarizes PSE's existing electric delivery infrastructure as of December 31, 2020. Electric delivery is accomplished through wires, cables, substations and transformers.

Figure M-1: PSE-owned Transmission and Distribution System as of December 31, 2020

PSE-OWNED ELECTRIC DELIVERY SYSTEM AS OF 12/31/20
Customers: **1,189,754**
Service area: 4,500 square miles
Substations: 353
Miles of transmission line: 2,743
Miles of overhead distribution line: 9,823
Miles of underground distribution line: 13,898
Transmission line voltage: 55-500 kV
Distribution line voltage: 4-34.5 kV
Customer site voltage: less than 600 V

How the Electric Delivery System Works

Figure M-2: Illustration of Electric Delivery System



Electricity is transported from power generators to consumers over wires and cables, using a wide range of voltages and capacities. The voltage at the generation site must be stepped up to high levels for efficient transmission over long distances (generally 55 kV to 500 kV).

Substations receive this power and reduce the voltage in stages to levels appropriate for travel over local distribution lines (between 4 kV and 34.5 kV). Finally, transformers at the customer's site reduce the voltage to levels suitable for the operation of lights and appliances (under 600 volts). Wires and cables carry electricity from one place to another. Substations and transformers change voltage to the appropriate level. Circuit breakers prevent overloads, and meters measure how much power is used. Distributed energy resources such as wind, solar and biodigesters are being added to the distribution system.

The electric grid, first built 1889, expanded in a highly radial, one-way flow design. Over time, the transmission system was looped in a network manner as outages across the nation drove voluntary standards and eventually regulations requiring operations with one or more elements out of service. In urban areas, a distribution system with looped feeders became common practice to improve reliability. It still operated in a radial, one-way flow manner, but as automation and protection devices mature, some parts of the distribution system are able to automatically switch to a different source.

Nearly 100 percent of the transmission system is networked and over 80 percent of PSE's distribution system is looped.

10-Year Electric Delivery System Plan

Increasing amounts of distributed energy resources like rooftop solar, growing electric vehicle loads, greater emphasis on demand-side resources and the clean energy transformation are changing the demands on the electric delivery system. The 10-year electric delivery system plan is designed to maintain safe, reliable energy delivery to customers, meet NERC compliance requirements and evolving regulations related to integration of distributed energy resources, and support the clean energy transformation and maximize its benefits. To meet these goals, in the next 10 years, PSE will:

- modernize the grid to ensure visibility, analysis, and control through investments in technology, analysis tools and infrastructure.
- ensure reliability and resiliency by leveraging technology capabilities and infrastructure.
- modernize the distributed energy resource (DER) integration processes to improve opportunities to optimize value
- maintain focus on cyber security and privacy
- address location-specific capacity, reliability and resiliency needs with major backbone infrastructure projects as needed

As discussed in Chapter 4, Planning Environment, integrated resource planning (IRP) and delivery system planning (DSP) are converging as delivery system solutions like distributed energy and demand-side resources play a larger role in meeting resource needs and deferring investment in traditional generating resources. The public engagement process for DSP planning will also be expanded and aligned with the IRP process as discussed in Appendix A, Public Participation.

This is an iterative process, and as integration proceeds, the sharing of data and results between the IRP and DSP processes will better inform future cycles and enable PSE to create more specific alignments between the IRP, the Clean Energy Action Plan and the Clean Energy Implementation Plan. As distributed energy connections grow in both numbers and total MWs, this integration is increasingly important. The 10-year electric delivery plan will continue to mature to fulfill the full intent of RCW 19.280.100 (2) (e) over the next several IRP cycles as new data, market research and cost/benefit studies are used to further develop the plan. Finally, PSE will continue to build on its robust delivery system planning and optimization process, leveraging strong cost/benefit analysis and rigor to inform scenario constructs while furthering integration with IRP processes.

PSE's active involvement in many expert and science-based research organizations such as the Western Energy Institute, Edison Electric Institute (EEI), Electric Power Research Institute (EPRI), and in distribution planning, distributed energy and resiliency groups, will support and enhance our efforts to meet our goal of maximizing the clean energy transformation benefits.

The 10-year electric infrastructure plan includes key investments in the areas of grid visibility, analysis and control; grid reliability and resiliency; cyber security and privacy; integrating distributed energy resources; and addressing backbone infrastructure needs. Figure M-3 summarizes the major elements of the plan. Discussion of the key investment areas in the following pages highlights the fact that these investment areas are interrelated. The 10-year plan addresses needs that are either existing or predicted based on the processes described in Chapter 8, Electric Analysis. Delivery system studies including NERC Planning Studies are performed every year, and these studies will surface new needs or constraints in future 10-year plans. In addition, the outer years of the plan may change substantially during this time of grid and load evolution. Like the IRP, the 10-year plan provides overall direction to inform decisions about specifically funded actions and plans.

Figure M-3: Summary of 10-Year Electric Delivery System Plan

10-YEAR ELECTRIC DELIVERY SYSTEM PLAN SUMMARY	
VISIBILITY, ANALYSIS AND CONTROL	
Foundational Technology	Advance Metering Infrastructure (AMI) Advanced Distribution Management System (ADMS) Distributed Energy Resource Management System (DERMS) / Virtual Power Plant (VPP)
Smart Equipment	SCADA devices GIS enhancements Geospatial Econometric Forecasting
RELIABILITY AND RESILIENCY	
System health replacements and upgrades to system components to address aging infrastructure	Upgraded transmission and distribution lines, transmission and distribution substations, cable replacement, worst performing circuits, pole replacement, and investments to ensure reliable "backyard sources."
As needed for integration of DERs and EV public charging.	Transformer upgrades, substation upgrades and circuit improvements

Reduce outage duration and enable DER effectiveness	Fault Location Isolation and Service Restoration (FLISR) and distributed automation
Manage increasing loads effectively and reliably	Demand response and time-of-use possibilities Reliable conservation New transmission lines, distribution lines and substations
Pilot projects to grow scalable technologies that solve delivery system challenges and build resiliency of communities and infrastructure	Microgrids
DER INTEGRATION PROCESSES	
Process maturity for efficient DER integration	Interconnection process refresh and customer engagement portal Hosting capacity capability and power flow tools Billing and administration process changes Non-wires solutions analysis process DER operating skills and procedures
SECURITY, CYBERSECURITY AND PRIVACY	
Ongoing security measures	Physical security of key assets Industry standards, protocols and requirements of technologies and vendors
ADDRESSING MAJOR BACKBONE INFRASTRUCTURE NEEDS	
Major backbone infrastructure projects are driven by capacity and reliability needs. These are discussed in detail starting on page M-14.	

Improving Visibility, Analysis and Control

Proactive investments in the foundational technologies that modernize the grid are critical to support the clean energy transition and maximize its benefits. The data availability, integrity and granularity they provide are essential to planning for and operating DERs, managing EV loads, and taking advantage of demand-side resources and non-wires delivery system solutions. These foundational technologies are described below.

ADVANCED METERING INFRASTRUCTURE (AMI). PSE is in year four of replacing the current aging and obsolete Automated Meter Reading (AMR) system and electric customer meters with Advanced Metering Infrastructure technology. AMI is an integrated system of smart meters, communications networks, and data management systems that gives both PSE and its customers greater visibility into customer use and load information and enables two-way metering between PSE and its customers.

In addition to ensuring reliable and accurate billing, the granularity of AMI data will allow PSE to respond to system needs quicker, support DER integration, offer advanced customer energy management tools and develop new rate structures to incent beneficial usage patterns. PSE has identified 38 unique use cases that could be implemented using AMI data, and time-of-use pricing pilots are currently under development.

ADVANCED DISTRIBUTION MANAGEMENT SYSTEM (ADMS). PSE is also replacing the obsolete Outage Management System with Advanced Distribution Management System technology. ADMS is a computer-based, integrated platform that provides the tools to monitor and control the distribution network in real time. In addition to outage management capabilities, ADMS provides visibility and control to SCADA devices, distribution system management and advanced applications.

The implementation of ADMS is expected to be completed by 2023. This will enable advanced operational capabilities for DERs, including an integrated Distributed Energy Resource Management System (DERMS). As DERs become more prevalent, PSE will need to (1) monitor and visualize DERs and their interactions with the distribution grid, (2) control the DERs and (3) dispatch them. DERMS allows us to perform these tasks. DERMS is in an early stage of maturity in the industry, so exact capabilities vary across technology vendors. When DERMS is integrated with ADMS, it will allow full visibility to the system operator and allow for safe and optimal dispatch coordinated with other operations activities. Prior to a fully integrated ADMS DERMS, PSE expects that acquisition of a Virtual Power Plant (VPP) will be required to monitor and dispatch DERs. While the VPP will not have full visibility to the distribution system, it will enable aggregation, forecasting and management of DERs to meet resource capacity needs.

SUPERVISORY CONTROL AND DATA ACQUISITION (SCADA). PSE anticipates completion of the Supervisory Control and Data Acquisition program at all substations by 2025 to provide real-time visibility and remote control of distribution equipment to reduce duration of outages, improve operational flexibility, and enhance overall reliability of the distribution system.

GEOGRAPHIC INFORMATION SYSTEM (GIS). DERs and transportation electrification are changing load patterns, but not evenly across the system. As a result, system planners require greater insight to the expected locations of DERs and EVs. Maintaining and augmenting PSE's GIS data will be increasingly central to developing the location-specific load information needed to plan for and manage these loads. PSE is working to evolve GIS processes so that changes in the field can be quickly incorporated and data such as DER asset information is collected and displayed.

GEOSPATIAL ECONOMETRIC FORECAST. PSE is also investing in a geospatial and econometric load forecasting tool to predict load and power changes, where on the grid the new loads will occur, how distributed generation (DG) changes the load shape, and when DG must be supplied. The tool will utilize GIS, SCADA, and AMI data along with customer and weather information to perform analyses that address both short-term circuit trends and long-term grid expansion. The resulting forecast provides system planners with substation, circuit and small-area resolution time-series load growth and load shape changes, including predicting asset replacement needs before failure as DERs are added to the grid. This tool provides key functionality that makes it possible to avoid reactive investments from DER integration and transportation electrification.

Improving Reliability and Resiliency

Improving reliability and resiliency involves both replacing aging infrastructure and upgrading it to meet load increases and prevent outages, but also leveraging technology to improve access to grid management strategies.

ENSURING A HEALTHY SYSTEM. To improve overall reliability, ensure DER effectiveness, and enable more opportunities for DER siting, PSE expects to replace or upgrade the following system components in the next 10 years. These programs will help to avoid reactive investments as a result of increasing loads and DERs, further enabling the opportunities to enable technologies for all communities.

- Replace the remaining approximately 1,300 miles of underground high molecular weight, failure-prone distribution cable by 2031.
- Address pole and pole cross arm health with completion of system inspection on 10-year cycle and remediation of poor health poles as well as programmatically addressing jurisdictional clear zone relocation requirements and upgrades to support internet and telecommunication infrastructure additions jointly located on PSE poles.
- Complete reliability improvement work on 135 worst performing circuits (WPC) with a 50 percent improvement sought by 2027 and continue targeting additional circuits that are underperforming PSE reliability metrics per PSE's reliability report.

- Install additional equipment protective devices to minimize large impacts due to outages, such as 200 fuse savers by 2025.
- Replace major substation components as a result of ongoing inspection and diagnostics.
- Invest in increasing reliability infrastructure to address the growing expectations of customers with energy sources in their “backyards.”
- Evaluate infrastructure that hardens PSE’s electric grid, such as spacer cable that is more resilient to tree fall-ins, and new pole components, such as steel cross arms to withstand wildfires.

MANAGING DERs AND EV CHARGING. PSE anticipates the need to proactively and programmatically address customer transformers, substation and circuit improvements to support the increase in DERs, electric vehicle charging and public charging sites. The specific delivery system investments needed will be identified as energy resources (whether centralized or DERs) are sited through established interconnection processes. Preparing the grid and customers for DER integration will decrease the cost of interconnection and increase the number of viable locations for DERs.

ENABLING FASTER SYSTEM OUTAGE RESTORATION. ADMS will enable enhancement of PSE’s current Distribution Automation (DA) program. Over the last few years, PSE has implemented Fault Location Isolation and Service Restoration (FLISR) as a part of a DA program that will be rolled out to about half of PSE’s circuits. FLISR is a combination of smart field devices controlled by centrally located software that provides self-healing capabilities to key feeders in the system. Currently PSE implements DA using a centralized, rules-based approach with stand-alone software. ADMS will enable a more flexible centralized, model-based approach that is considered more sustainable and flexible than the rules-based approach because it allows the FLISR process to continue operation under different switching configurations. This is especially important as the grid becomes more complex and customer expectations for reliability grow.

MANAGE INCREASING LOADS. With increasing EVs and movement toward electrification, PSE’s load will continue to increase, requiring greater emphasis on relieving local capacity constraints. Lowering energy use through increased access to demand-side resources is a useful grid management tool that PSE can utilize to improve reliability and resiliency. Leveraging AMI and ADMS, PSE will be able to pursue additional demand-side resources through local programmatic reliable energy efficiency, conservation voltage reduction (CVR), volt-var optimization (VVO) and demand response. These measures lower customers’ energy use through reduction in supply voltage. The AMI project allows PSE to more broadly implement the CVR program for circuits fed from approximately 164 substations. When ADMS is fully installed, the CVR program will mature to volt-var optimization which uses end-of-line voltage information from AMI meters to optimally manage system-wide voltage levels and reactive power flow to achieve efficient distribution grid operation. This dynamic voltage management approach will also support the integration of intermittent renewables and new transportation electrification loads. PSE will continue to build on its demand response experience using AMI data and modeling tools to help solve projected needs. As PSE pursues its time-of-use pilot, lessons will benefit local applications to manage loads and defer infrastructure investments.

PSE anticipates that leveraging energy-saving technologies will help address some local delivery system capacity constraints, but not all, due to the local characteristics of a circuit or area. In addition to the major electric backbone infrastructure projects described below, approximately eight new distribution substations will be needed to serve load beyond what the existing substation capacity can serve, and approximately four existing substations will need to be upgraded to replace aging infrastructure. This will also require building out or reconfiguring the associated distribution lines.

BUILDING RESILIENT COMMUNITIES. DERs can play a part in increasing resiliency in specific locations through microgrids or by supporting local reliability. PSE is conducting two pilot projects involving microgrids and DER integration to test how these strategies can improve reliability and resiliency in places such as highly impacted communities, transportation hubs, emergency shelters and areas at risk for isolation during significant weather events or wildfires. This allows PSE to test use cases and develop technical capabilities, and the learnings from both pilots (described below) will be used to inform future planning in areas where PSE seeks to provide additional reliability, resiliency and integrate DERs for highly impacted communities. PSE continues to review lessons from pilot projects such as Glacier Battery, Bainbridge behind-the-meter batteries, and a commercial-scale battery installed at our Poulsbo office.

The Samish Island Community Demonstration serves a fire station and nearby homes on Samish Island in Skagit County. This project deploys a front-of-the-meter battery with roof-top solar panels and other smart equipment, switches and controls and will test a community battery's ability to manage solar integration, form a microgrid to 'island' the fire station for emergencies and provide temporary backup power.

The Tenino Microgrid project, partially funded through a Clean Energy Fund Grant from the Washington State Department of Commerce, will install an approximately 1 MW/2 MWh lithium-ion battery at PSE's Blumaer substation and solar array on adjacent land, complementing existing solar panels at nearby Tenino High School. Combined, the system will form a microgrid capable of providing temporary backup power to the school during an outage. Installation of a second battery in the Tenino area is planned to enhance local reliability.

Modernizing DER Integration Processes

In addition to the enabling technologies, analytical capabilities and system component upgrades PSE is implementing to support the growing role of DERs (discussed above), PSE is investigating options and requirements for an enhanced web-based interconnection portal that would streamline the interconnection process for both customers and developers by prescreening applications. The portal would make use of geospatial load forecasts, hosting capacity analysis and power flow modeling. Additional customer tools, such as modifications to billing systems and program administration and design, may be needed as PSE's operating model moves from traditional one-way power flow to two-way energy flow and delivery.

PURSUING NON-WIRES SOLUTIONS. As part of integrating the delivery system and energy resource planning processes, PSE has been expanding its technical skill and processes relative to non-wire alternative analysis and valuation of DERs that have the potential to defer traditional wire solutions, where effective. The four non-wire alternatives analyses PSE performed in Bainbridge Island, Lynden, Seabeck and West Kitsap are described in detail in the sections on major infrastructure projects. As noted in Chapter 2, Clean Energy Action Plan, and Chapter 5, Key Analytical Assumptions, when PSE's non-wire alternative analysis determines DERs are part of viable cost-effective solutions, they are included in the electric portfolio modeling and embedded in the preferred portfolio. Pursuing these solutions will require training program enhancements, process and procedure modification, and potentially additional workforce requirements. PSE will continue to screen new needs for non-wire alternative potential in support of this forecast and refine data and tools as more is learned.

Maintaining Strong Security, Cyber Security and Privacy

As critical infrastructure becomes more technologically complex, it is even more crucial for PSE to adapt and mature the physical security of key assets and cybersecurity practices and programs that make it possible to take advantage of new technology opportunities such as Internet of Things devices. To ensure risks are consistently addressed and mitigated in alignment with the rapidly changing security landscape, PSE utilizes a variety of industry standards to measure maturity as each standard approaches security from a different perspective. In addition, we foster strong working relationships with technology vendors to ensure their approach to cybersecurity matches PSE's expectations and needs. PSE's telecommunications strategy will evolve to support required security and reliability, leveraging existing communication networks such as the AMI communication mesh network.

Major Backbone Infrastructure Projects

Major infrastructure projects are driven by increasing loads and reliability needs and proceed in two phases. The **initiation phase** includes the development of the need and evaluation of alternatives and identification of a proposed solution. The **implementation phase** includes project planning for which the need and proposed solution is tested, followed by design, permitting and construction. Once a project is in implementation, location specific activities begin, including the engagement with the local community. Informational updates are provided through the IRP process for projects in this phase. PSE is working to develop more detailed engagement with the IRP stakeholders when a project is in the initiation phase.

Chapter 5, Key Analytical Assumptions, includes a discussion relative to the forecast of non-wire alternatives that may result in cost-effective DER solutions. The IRP results expect to harvest those solutions to support resource needs. PSE will deploy identified, project-specific non-wires solutions to support the near-term integration of 22 MW of DERs and continue to validate the DER forecast to realize predicted solutions to meet resource needs. The 22 MW DER forecast includes a combination of specific major backbone infrastructure projects and additional projects necessary to address specific growth areas over the next 10 years as detailed in the sections below. The projects identified as NWA candidates were specifically identified as those which were suitable for non-wire alternatives.

The specific project descriptions in the following pages are divided into the two phases described above. They include summaries of the need and solution identified for each project, as well as detailed descriptions of recently completed non-wire alternative analysis for four projects.

Major Electric Projects in Implementation Phase

Figure M-4 summarizes the planned projects in the project implementation phase, which includes design, permitting, construction and close-out. Learnings from the non-wires analysis pilots for the Bainbridge Island and Lynden projects will be applied to future projects in the initiation phase.

Figure M-4: Summary of Major Electric Projects in Implementation

SUMMARY OF MAJOR ELECTRIC PROJECTS IN IMPLEMENTATION	ESTIMATED IN-SERVICE YEAR
1. Sammamish – Juanita New 115 kV Line	2023
2. Eastside 230 kV Transformer Addition and Sammamish-Lakeside-Talbot 115kV Rebuilds (Energize Eastside)	2022
3. Electron Heights – Enumclaw 55-115 kV Conversion	2024
4. Sedro Woolley - Bellingham #4 115 kV Rebuild and Reconductor	2024
5. Bainbridge Island (NWA Analysis Pilot)	2024
6. Lynden Substation Rebuild and Install Circuit Breaker (NWA Analysis Pilot)	2024

1. Sammamish – Juanita New 115 kV Line[1]

Estimated Date of Operation: 2023

PROJECT NEED. Improvements must be made to increase transmission capacity and reliability in the Moorlands area. The existing system serves 56,000 customers in 5 cities from 12 substations with three transmission lines built more than 50 years ago using small wire. PSE's annual transmission system assessment to meet NERC reliability standards indicates multiple contingency (N-1-1) overload issues in the Moorlands area. Both winter and summer seasons are impacted. Interim operating plans have been developed to sectionalize lines and drop load if necessary to prevent overloads and meet NERC requirements, but this reduces customer reliability. PSE Planning Guidelines call for a fourth line when serving a commercial area in which load exceeds 150 MW. Credible outage scenarios could force one of the three lines to serve the entire 12-substation area.

1 / *https://www.pse.com/pages/pse-projects/sammamish-juanita-transmission-line*

SOLUTION IMPLEMENTED. Install 4.65 miles of new 115 kV transmission line, reconductor 0.15 miles of existing 115 kV transmission line between NE 124th St. and Juanita Substation, loop the Totem Lake Substation, and install supervisory control and automatic switching on switches on either side of Crestwood Substation.

CURRENT STATUS. The project is in design and permitting.

2. Eastside 230 kV Transformer Addition and Sammamish – Lakeside – Talbot 115 kV Rebuilds (The Energize Eastside Transmission Capacity Project)[2]

Estimated Date of Operation: 2022

PROJECT NEED. The backbone of the Eastside electrical system has not had a voltage upgrade since the 1960s. Since then, Eastside's population has grown from approximately 50,000 to nearly 400,000, and growth is expected to continue. Currently, electricity is delivered to the area through two 230 kV/115 kV bulk electric substations – Sammamish substation in Redmond and Talbot Hill substation in Renton – and distributed to neighborhood distribution substations using the many 115 kV transmission lines located throughout the area. PSE's annual transmission system assessment to meet NERC reliability standards completed in 2013 and 2015 demonstrated PSE could not meet federal reliability requirements in the area by the winter of 2017-18 and the summer of 2018 without the addition of 230 kV/115 kV transformer capacity. Overloads will impact the reliable delivery of power to PSE customers and communities in and around Redmond, Kirkland, Bellevue, Clyde Hill, Medina, Mercer Island, Newcastle, Renton, and the towns of Yarrow Point, Hunts Point and Beaux Arts among others. The supply issue focuses on the two 230 kV supply injections into central King County at Sammamish substation in the north and Talbot Hill substation in the south. The winter load level was expected to exceed capacity around the winter of 2017-18, and the summer load level was expected to exceed capacity in the summer of 2017. PSE's annual assessment also identified that primary driver of need was the forecasted summer overload. These possible overloads would result in operating conditions that put thousands of Eastside customers at risk of outages.

SOLUTION IMPLEMENTED. Install a 230 kV/115 kV transformer substation in the center of the Eastside load area and a rebuild of the 115 kV Sammamish – Lakeside – Talbot #1 & #2 lines to 230 kV to provide additional transmission capacity to serve projected load growth.

CURRENT STATUS. This project is in permitting with approval of the Environmental Impact Statement, and Bellevue Conditional Use Permit (CUP). The Bellevue CUP is currently being appealed.

2 / *https://www.energizeeastside.com*

3. Electron Heights – Enumclaw 55-115 kV Conversion[3, 4]

Estimated Date of Operation: 2024

PROJECT NEED. NERC reliability requirements for multiple contingencies identify this project as needed to prevent transmission system voltage collapse, overloading of the 115/55 kV transformers at Krain Corner, Electron Heights and White River, and overloading of the White River-Krain Corner 55 kV line. The project provides additional 115 kV support at Krain Corner and Electron Heights substations. It also provides the needed 115 kV supply for the new Buckley substation as well as needed improvement to the reliability of both the Electron Heights-Stevenson, and Krain Corner-Stevenson transmission lines through protection improvements and creation of the 115 kV loop.

SOLUTION IMPLEMENTED. Convert 22 miles of transmission line between Electron Heights and Stevenson substations from 55 kV to 115 kV operation, including the conversion of Wilkeson Substation and construction of a new Buckley 115 kV substation. The 55 kV equipment at Electron Heights Substation will be converted to 115 kV. The transmission line will connect through the Enumclaw Substation creating a complete 115 kV transmission loop from Electron Heights to Krain Corner substations; this will allow for the removal of Stevenson Substation, which will be a great benefit to the local community. One and one-quarter miles of the transmission line will be reconductored, and a short section of new 115 kV line will be built to maintain 55 kV service to the Greenwater Tap.

CURRENT STATUS. This project is in final design, permitting and property acquisition.

4. Sedro Woolley – Bellingham #4 115 kV Rebuild and Reconductor

Estimated Date of Operation: 2024

PROJECT NEED. There are several needs for this project. First, the low-capacity line ratings could cause the line to exceed its allowable ratings for several contingencies and limit generation capacity in Whatcom and Skagit Counties. The small copper wires could also cause high line losses, and the aging infrastructure could lead to extended outages. Second, the low capacity of the Bellingham-Sedro Woolley #4 line has caused constraints on regional power flows for over twenty years due to the parallel higher-voltage transmission line which requires PSE to protect the line from loading above its allowable limits by automatically opening the Sedro Woolley substation circuit breaker. Opening this breaker (and subsequently the line) reduces system reliability in both Whatcom and Skagit Counties, including the Norlum and Alger substations. The

3 / *https://www.pse.com/pages/pse-projects/electron-heights-enumclaw-transmission-line-and-substation-upgrades*
4 / *https://www.pse.com/pages/pse-projects/buckley-substation*

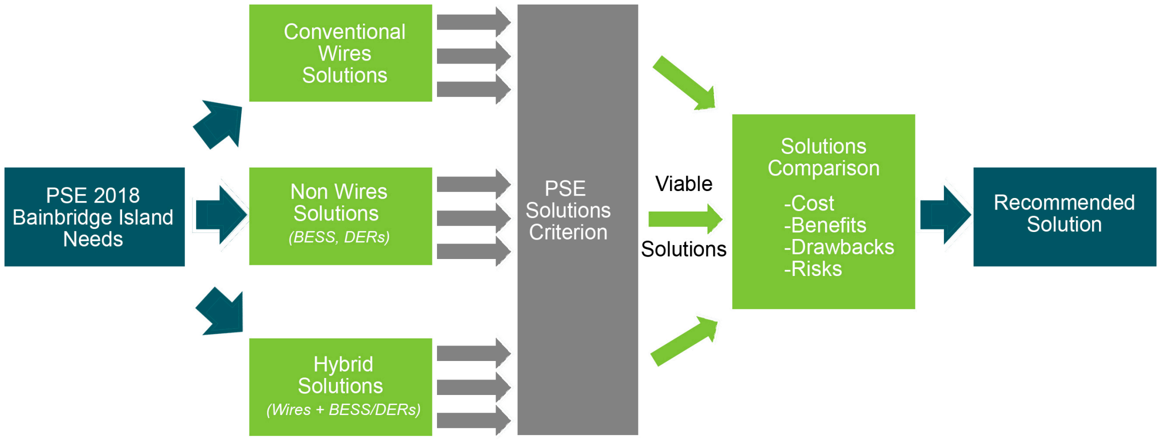
6,240 customers served from the Norlum and Alger substations are at an increased risk of outage during such time as each substation has only one transmission source. Finally, the line's aged equipment has contributed to 27 momentary outages and 4 sustained outages in the five years prior.

SOLUTION IMPLEMENTED. Rebuild and reconductor the existing 24-mile Sedro Woolley-Bellingham #4 115 kV line which connects the Skagit County and Whatcom County 115 kV systems and directly feeds two distribution substations, Alger and Norlum. To coordinate concurrent distribution system upgrades, this project is being constructed in five phases: Phase A includes approximately 4 miles of the line in Skagit County; Phase B includes approximately 7.5 miles of the line in Skagit County; Phase C includes approximately 6 miles of the line in Skagit and Whatcom Counties; Phase D includes approximately 6 miles of the line in Whatcom County; and Phase E rebuilds the final 0.5 miles of the line in Skagit County.

CURRENT STATUS. This project was initiated in 2010. Phase A was placed in service February 2018; Phase B was placed in service December 2018. Phase C, D and E are in design and permitting.

PSE has selected four areas of future needs to test, enhance and develop the planning process for integrating non-wires solutions: Bainbridge Island, Lynden, Seabeck and Kitsap. Bainbridge Island and Lynden have completed the planning process and are now in the implementation phase of project development. The following project descriptions provide insight into the process, initial findings and challenges in these areas. Seabeck and Kitsap are still in the planning phase and follow in the next section. In each area, PSE performed an electrical system needs assessment and identified key needs for grid investment. Next, solutions criteria for system performance were developed for the key needs. Alternative solutions were considered in three categories: 1) conventional wire solutions, 2) non-wire solutions consisting of battery storage and distributed energy resources (DER), and 3) hybrid solutions involving a combination of wires and non-wires components. Solutions were considered viable if they met all identified system needs and the performance standards set in the solutions criteria. Finally, a solutions alternatives analysis was conducted in order compare the costs for all viable solutions, and a solution was selected based on cost, benefits, drawbacks, risks and benefit-to-cost ratio. A diagram of the solutions process is shown below in Figure M-5.

Figure M-5: Solutions Process Overview



PSE engaged the services of two consulting firms, Navigant and Quanta, to assist in preparing the four non-wire analysis (NWA) and the combined teams worked for well over a year. The Bainbridge and Lynden project analyses are complete. The Seabeck and West Kitsap analyses are under review, and PSE is identifying solutions that will satisfy the needs assessment for each of the projects.

5. Bainbridge Island (NWA Analysis Pilot)[5]

Estimated Date of Operation: 2024

The Bainbridge Island transmission and distribution system serves 12,450 customers in Kitsap County from 3 substations and two 115kV transmission lines. The island is served by two parallel transmission lines via one water crossing from Suquamish.

NEED ASSESSMENT. PSE begins studying an area when certain study triggers occur based on the system health, operations, load growth projections and other information that surfaces. Data is gathered and assumptions are made as follows.

Planning Study Triggers

- Transmission reliability
- Aging infrastructure on the Winslow Tap transmission line
- Load forecasted to exceed 85 percent of substation group capacity in 2019

5 / *https://www.pse.com/pages/pse-projects/bainbridge-island-electrical-system-improvements*

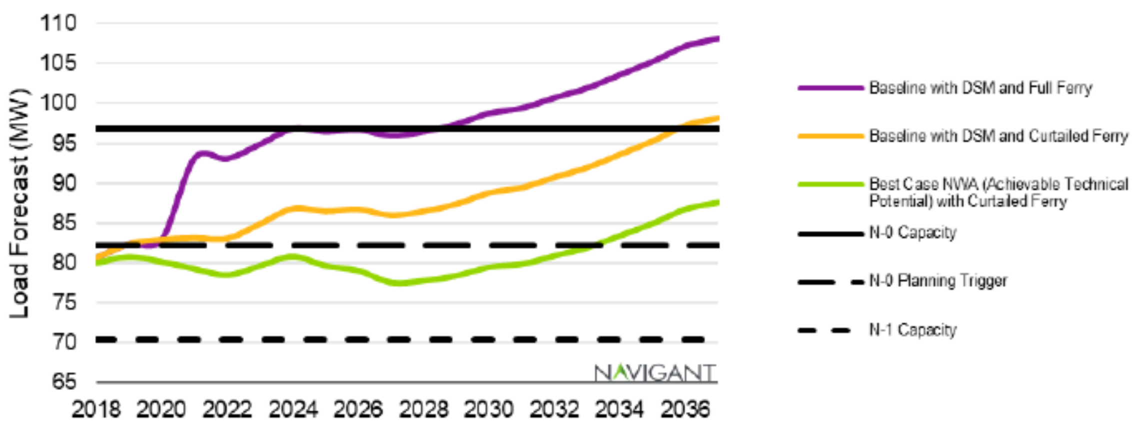
Data and Assumptions

- PSE's system load forecast net of conservation and known block load additions
- Current substation loading
- Outage data from 2013 through 2017

NEEDS IDENTIFIED. These include capacity, reliability, aging infrastructure and operational flexibility.

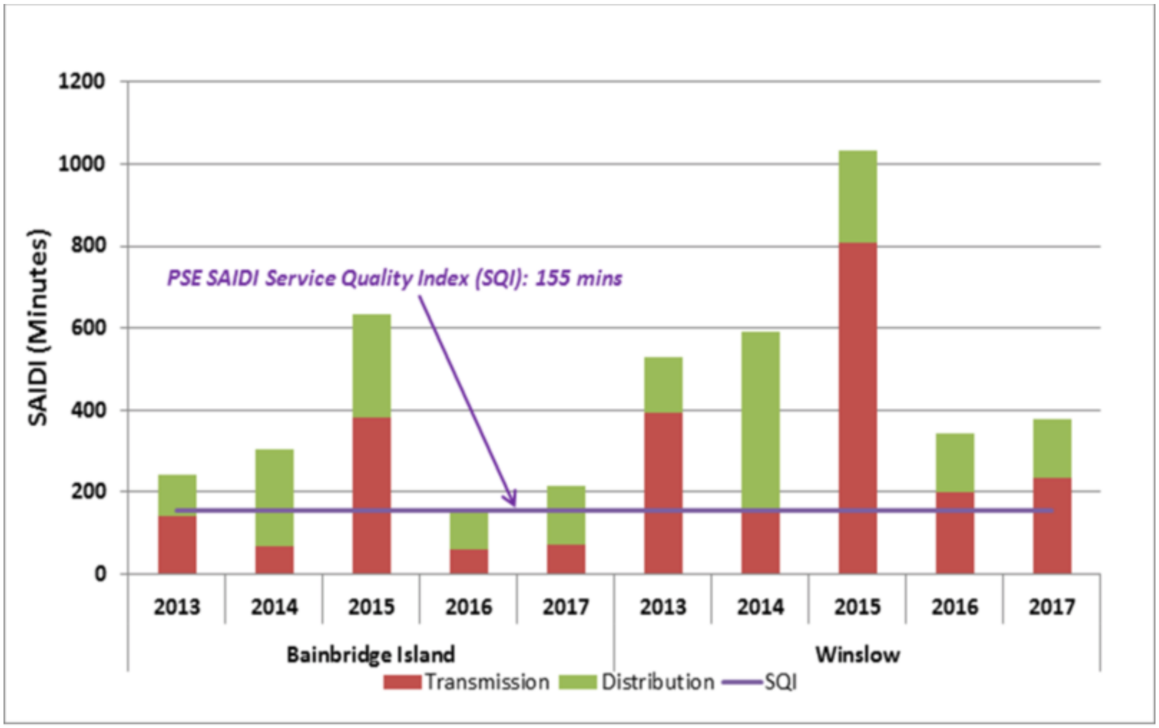
Capacity: Additional capacity will be required to meet projected load growth on the island over the next 10 years and the potential electric ferry charging facility as early as 2021.

Figure M-6: Bainbridge Island Potential Non-wires Forecast Scenarios



Reliability: Performance of the transmission source feeding the Winslow substation needs to be improved. Forty-seven percent of the total customer minutes of interruption to Bainbridge Island between 2013 and 2017 were caused by transmission outages. Nearly 70 percent of the 5-year total customer minutes of interruption were caused by Winslow transmission outages.

Figure M-7: Comparison of Bainbridge Island and Winslow SAIDI Performance



Aging Infrastructure: PSE's 2019 field inspection determined that 50 percent of the Winslow transmission tap wishbone-type crossarms will require replacement in the next one to three years.

Operational Flexibility: There was an operational flexibility concern related to the ability to transfer load to support routine maintenance and outage management. Winslow and Murden Cove substations are on radial transmission taps and have no operating flexibility at the transmission level.

SOLUTION ASSESSMENT. Solution criteria includes technical criteria and non-technical criteria as follows.

Technical Solution Criteria

- Must meet normal winter peak load forecast with 100 percent conservation
- Must be ≤ 85 percent of substation group utilization
- Must not re-trigger any of the needs identified in the Needs Assessment for 10 years or more after the project is in service

<u>Non-technical Solution Criteria</u>

- Feasible permitting
- Reasonable project cost
- Uses proven technology that may be adopted at a system level
- Constructible within reasonable timeframe

<u>Evaluation of Solution Alternatives</u>

PSE conducted a solutions alternatives analysis to determine a cost-effective solution that meets all identified system needs for Bainbridge Island over a planning horizon of ten years (2018-2027). A solution was considered viable if it met all identified system needs and the performance standards set in the solutions criteria.

Alternative solutions were considered in three categories.

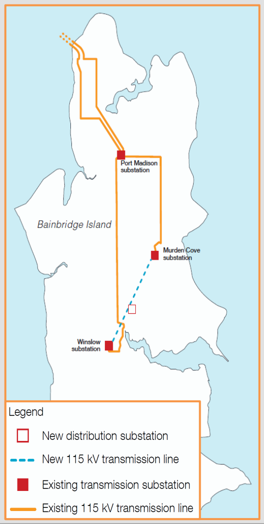
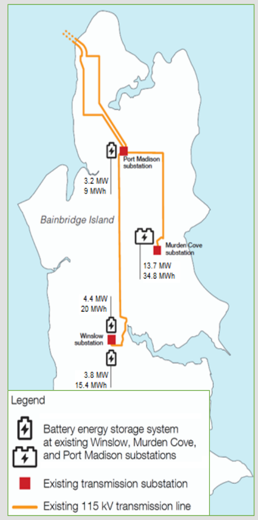
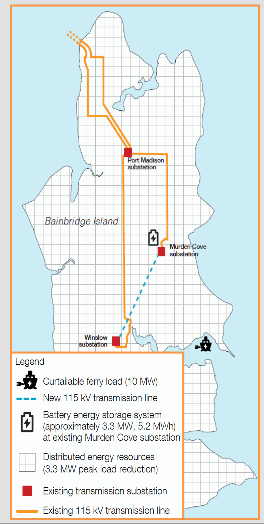
1. Conventional wire solutions
2. Non-wire solutions consisting of battery storage and distributed energy resources
3. Hybrid solutions involving a combination of wires and non-wire components

Eight alternatives were evaluated. These included three variations of traditional transmission line and substations alternatives, one alternative using all battery storage to meet need and five hybrid alternatives. Three alternatives were determined to be viable as a result of the analysis.

PSE concluded that a non-wires-only solution appeared technically feasible but that it would result in a higher cost than the wires solution, a lower benefit/cost ratio, involve significant disruption to Bainbridge Island, and likely not be ready in time to meet the projected load of the new electric ferry charging station.

Given these drawbacks, PSE considered potential hybrid solutions that included both conventional wired components and non-wired components. The technical potential and economic analysis concluded that a non-wires portfolio of energy efficiency, energy storage, renewable distributed generation and the option of demand response had the potential to cost-effectively defer the wired alternative of a distribution substation for capacity need until 2030 given current load forecasts. The consultants recommended sizing the energy storage to meet 50 percent of capacity needs in 2030; their analysis indicated that a 3.3 MW/5 MWh battery would provide sufficient flexibility for PSE to study and pilot targeted demand response and energy efficiency programs to meet the other 3.3 MW of need before other delivery system measures become absolutely necessary.

Figure M-8: Viable Alternatives for Bainbridge Solution

	Wired Alternative	Non-Wired Alternative	Hybrid Alternative
Solution Overview			
Primary Need: Winslow Tap Transmission Reliability	Transmission Loop	Total BESS: 25.1 MW/79.2 MWh MUR: 13.7 MW/34.8 MWh MUR-14, MUR-15, PMA-13: 7 MW/24.4 MWh WIN-13: 4.4 MW/20 MWh	Transmission Loop
Primary Need: Substation Group Capacity	New Dist. Substation		Ferry Curtailment: 10 MW up to 182 hr. 50% BESS @MUR: 3.3 MW/5 MWh 50% DER: 3.3 MW
Primary Need: Winslow Tap Aging Infrastructure	Replace Aging Poles; Improve Corridor Access and Veg Mgmt; Perfect Rights	Replace Aging Poles; Improve Corridor Access and Veg Mgmt; Perfect Rights	Replace Aging Poles; Improve Corridor Access and Veg Mgmt; Perfect Rights
Decision Factors	- Expertise - Long term solution - No ferry impact - High reliability	- New technology - 10 year solution - Ferry impact - Add with growth - New operations	- New technology - 10 year solution - Ferry impact - Add with growth - New operations - Local EE and DR
Benefit/Cost Ratio * Preliminary and subject to change	3.73	1.82	4.47

The hybrid solution has an estimated baseline cost of $24.3M compared to an estimated baseline cost of $28.7M for the wired solution. The hybrid solution also presents the opportunity to increase learning about adoption of energy storage and distributed energy resources as a method for deferral of electric system needs.

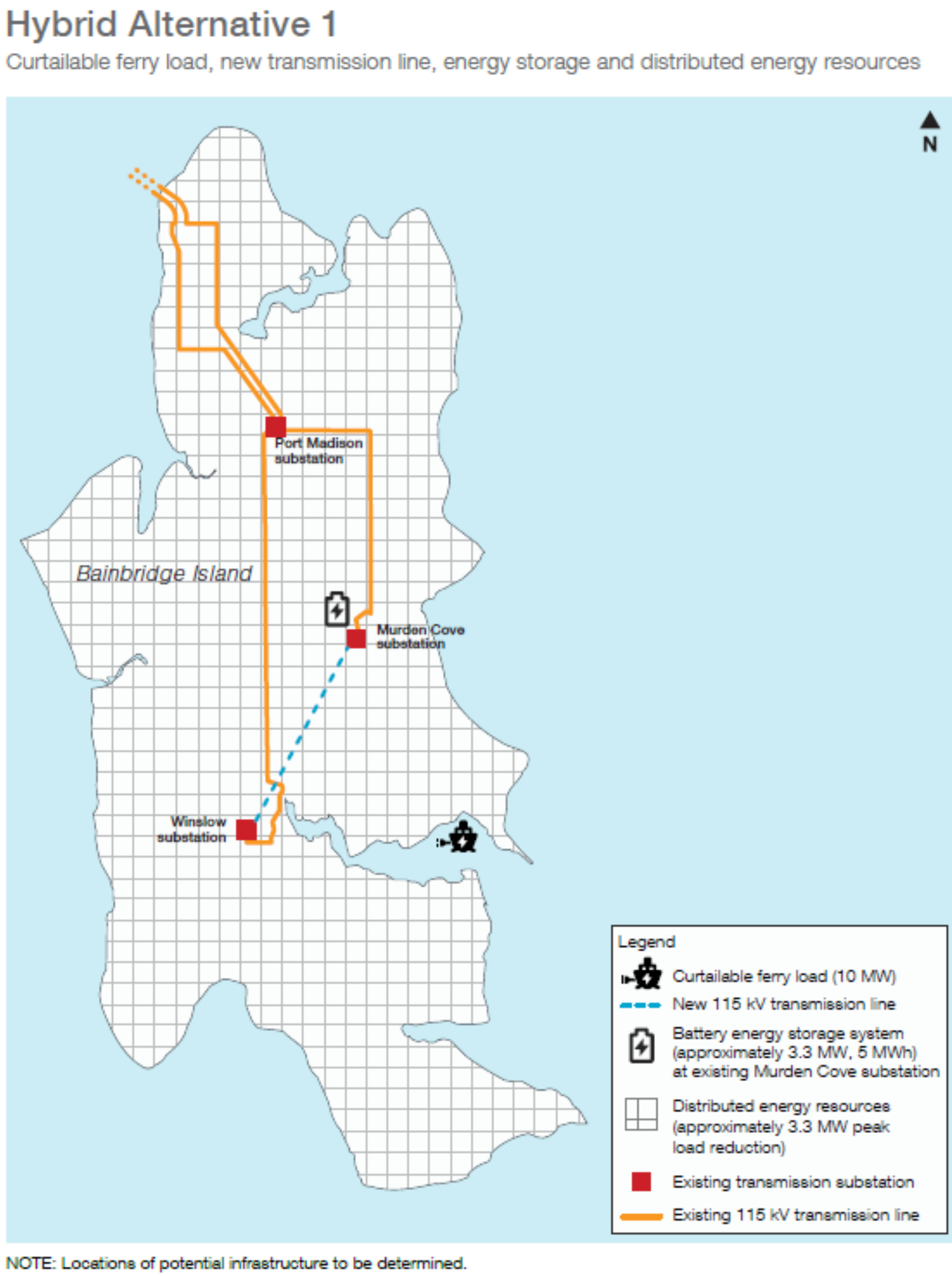
<u>Preferred Solution</u>

The preferred solution to further evaluate is the hybrid solution using traditional wired investment for the transmission and distribution reliability needs and a combination of energy storage and DERs for the distribution capacity need and reliability improvement.

The primary components of this solution are:

- An approximately 3.3 MW energy portfolio including energy efficiency, renewable distributed generation and the potential for demand response
- An approximately 3.3 MW/5 MWh battery located at Murden Cove substation
- 3.5 miles of new overhead 115kV line between Murden Cove and Winslow substations to create a transmission loop
- Replacement of 50 percent of poles and crossarms and improvement of the corridor for maintainability and operability of the Winslow transmission tap
- Connection of the 10 MW ferry load as a curtailable resource

Figure M-9: Bainbridge Island Hybrid Solution



CURRENT STATUS. This solution is in the development stage with an energy storage team and a DER team performing initial scoping strategy.

6. Lynden Substation Rebuild and Install Circuit Breaker (NWA Analysis Pilot)

Estimated Date of Operation: 2024

The Lynden substation serves 6,300 customers in Whatcom County, PSE's most northern area. The equipment is aging, and due to the site configuration, performing necessary maintenance and repair work is difficult. This in turn limits operational flexibility. One of the substation transformers is nearing end of its life based on the substation's health report and needs replacement by 2021. The existing substation yard and equipment configuration will not support replacement with a standard transformer.

NEED ASSESSMENT. PSE begins studying an area when certain study triggers occur based on the system health, operations, load growth projections and other information that surfaces. Data is gathered and assumptions are made as followed.

Planning Study Triggers

- Equipment age and condition
- Lack of transmission line circuit breaker
- Possibility of Remedial Action Scheme (RAS)
- Substation operational concerns
- Distribution reliability and operation concerns including capacity triggers

Data and Assumptions

- Assessment horizon – the ten-year period from 2018 to 2027
- Whatcom County local area demand forecast from PSE's F2017 Load Forecast, which estimated average annual demand growth of 0.66 percent over 10 years
- Assume the 2018 feeder extension project enables Lynden Circuit 26 to tie to Lynden Circuit 23, thereby enabling some load transfer to delay further feeder capacity upgrades
- Current substation loading
- Outage data from 2013-2017
- Asset health information from pole inspection data (2019 and previous years)
- Maintenance and operating history
- Power flow analysis consistent with North American Electric Reliability Corporation (NERC) TPL-001-4 requirements
- Assessment is in compliance with PSE's Transmission Planning Guidelines and Distribution Planning Guidelines

NEEDS IDENTIFIED. Aging infrastructure, reliability and operational needs exist presently and over the next 10 years. The next substation upgrade is recommended by 2021 for aging equipment replacement and may be needed by 2023 for load growth.

Aging Infrastructure. The Lynden Bank 2 transformer, rated 12/16/20 MVA, 115 -13.09 kV Y-Δ-Y, was installed in 1967. Its 2.0 MVA regulator was manufactured in 1965. A condition assessment of the Bank #2 transformer and regulator was performed by PSE's Technical Field Services (TFS) group in April 2018. The TFS Condition Assessment Report recommended that Bank 2 (XFR0196 and REG0277) be removed from service and replaced with a new LTC transformer within the next three years. PSE's Asset Management Group has planned to replace the transformer by 2026, based on economic life, by which time it would be 59 years old.

Reliability. One of the three transmission lines at the substation does not have a circuit breaker where the line connects to the 115 kV bus. This causes reliability impacts to all 6,300 Lynden Substation customers and risks momentary outages to another 15,700 customers in northern Whatcom County. A fault on this line also triggers a generation Remedial Action Scheme (RAS) at Sumas generating plant, removing 160 MW of generation from PSE's system twice as often as would be required if the transmission line had a circuit breaker. Additionally, during the five-year period from 2013 through 2017, the main contributor to high customer minutes of interruption (CMI) in the Lynden area was a wind storm on August 29, 2015. This storm significantly impacted Whatcom County. All three transmission lines to Lynden were out of service between 12:45 p.m. and 7:46 p.m. Each line had multiple outages during the storm, some of which were restored automatically prior to a permanent fault event.

Figure M-10 : Lynden Transmission Interruptions 2013-2017

CMI TRANSMISSION INTERRUPTIONS, 2013-2017			
Full Line Name	**Line Number**	**Total No. of Faults**	**CMI**
BPA Bellingham - Lynden (115 kV)	77	1	4,470,730
Portal Way – Lynden (115 kV)	264	2	576,928
Sumas – Lynden (115 kV)	167	2	279,162
Sumas – Bellingham (115 kV)	2	9	1,855,415
PSE Average 115 kV Line		4.5	3,071,838

Studies indicate there are areas of potential low voltage (< 113 volts) on LYN circuits that are could occur under N-0 conditions. Finally, there is one distribution circuit, LYN-14, that is above the system average for CMI with a value of 125,631 minutes (105 percent of system average).

The annual CMI reliability performance data for all LYN circuits from 2013 through 2015 is summarized in Figure M-11.

Figure M-11: Annual CMI Reliability Performance Data for 2013-2015

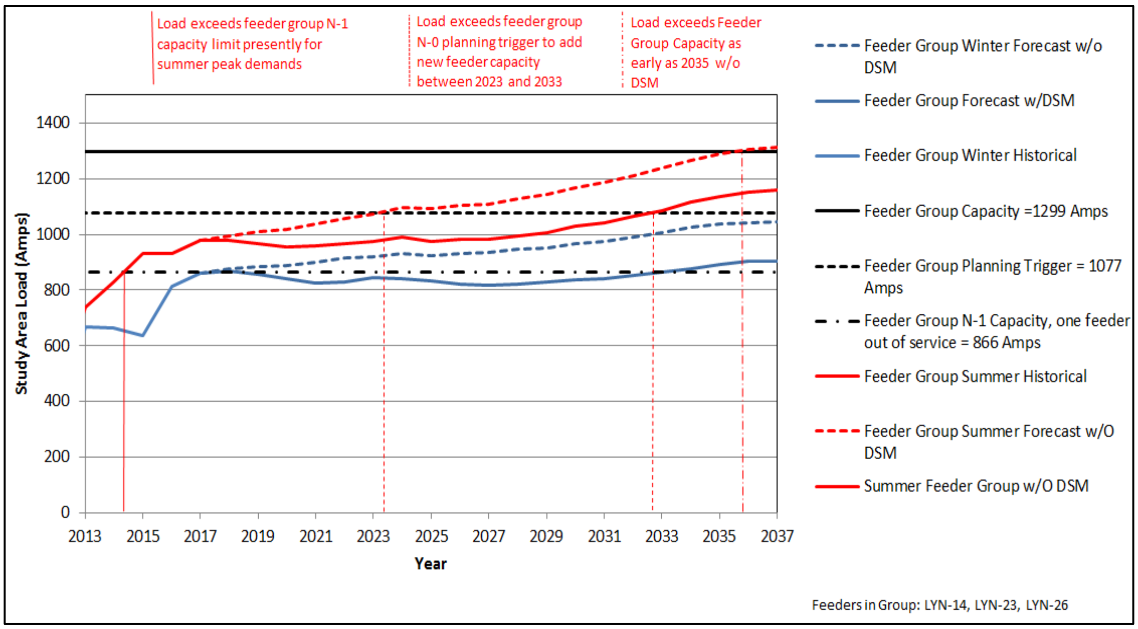
Non-MED CMI (IEEE, T_{MED} adj for catastrophic storm), Minutes				
Circuit	**2013**	**2014**	**2015**	**Average (2013-2015)**
LYN-13	53,774	47,035	13,464	38,091
LYN-14	46,226	325,861	4,806	125,631
LYN-16	787	-	278	355
LYN-17	46,596	47,058	6,352	33,335
LYN-23	219	711	7,657	2,862
LYN-24	27,460	102,883	211,164	113,836
LYN-26	39,556	130,062	27,900	65,839

Operational Flexibility. The existing layout affects reliability, future growth, and the ability to move workers and equipment in the substation to perform work.

- The crowded substation has more equipment than is usually found in a substation of this size, challenging crew ability to work efficiently and safely.
- There is not enough space in the substation for the upgrades required to replace the Bank 2 transformer. These upgrades include improvements to the control house and the Bank 2 feeder structure.
- Substation controls are spread among three control houses and a battery structure, with no room for more control equipment.
- Most double-banked substations have a bus tie switch between feeder structures; however, the Lynden substation does not. Without the bus tie switch, extensive field switching is required when taking a substation transformer out of service. Unplanned bank outages are longer in duration due to multiple distribution switching steps.

Capacity. Load growth within Whatcom County is uneven and Lynden Substation includes only a portion of the county, so the project team developed local load growth forecasts considered reasonable based on historical load growth and known load additions. Figure M-12 illustrates historical and projected demand for the 20-year F2017 load forecast for the LYN-14, 23, 26 Feeder Group. This figure also illustrates the N-1 planning trigger and capacity limits of the station group. Projected demand is shown both with and without adjustment for demand-side measure (DSM) effects. The planning trigger to add N-0 station capacity to this study grouping could be reached in 2037 without DSM.

Figure M-12: Projected Demand for LYN-14, 23, 26 Feeder Group



SOLUTION ASSESSMENT. Solution criteria includes technical and non-technical criteria as follows.

Technical Solution Criteria

- Must meet all performance criteria for transmission and distribution
- Address all relevant PSE equipment violations identified in the Needs Assessment
- Address all relevant needs identified in the Needs Assessment Report
- Must cause no adverse impacts to the reliability or operating characteristics of PSE's or surrounding systems
- Must not re-trigger any of the needs identified in the Needs Assessment for 10 years or more after the project is in service
- Must not increase non-MED SAIDI and non-MED SAIFI
- Address key infrastructure impacted by replacements to aging infrastructure

Non-technical Solution Criteria

- Feasible permitting
- Reasonable project cost
- Uses proven technology that may be adopted at a system level
- Constructible within reasonable timeframe

Evaluation of Solution Alternatives

Determining which parts of Lynden's needs could be met with non-wires components was more complicated than in the other three areas where PSE is piloting non-wires analysis. The interdependent needs presented an opportunity to further develop a framework for the initial assessment of project needs that takes place prior to investigation of non-wires alternatives.

The potential to solve Lynden needs using non-wires alternatives, including a combination of energy efficiency, demand response, solar photovoltaic, and distributed generation was evaluated. PSE concluded that a non-wires-only solution did not appear to be technically feasible. It was determined that critical upgrades needed to meet operational flexibility concerns and transmission reliability could not be solved by a non-wires solution, so any scenario analyzed to solve all of the identified needs would need to be a hybrid solution. In considering the type of needs that might be met with NWAs, Navigant noted that "NWAs are typically developed to address needs that tie directly to capacity constraints, and less typically to address other types of needs." For this reason the team investigated whether any of the needs were connected to capacity constraints. An alternative was considered that would utilize DERs and energy storage to remove rather than replace the aging transformer. This alternative would include critical substation upgrades only and would not include transformer replacement and associated metal clad feeders and substation expansion. Ultimately six solutions were considered to solve the needs identified at Lynden.

Figure M-13 shows the traditional wired solutions and hybrid solution that were developed. PSE conducted a solutions alternatives analysis for these alternatives to determine the most cost-effective solution that meets all identified system needs for Lynden over a planning horizon of ten years (2018-2027). The analysis identified Alternative 3 to have the greatest benefit for cost to improve the substation.

Figure M-13: Six Lynden Substation Alternatives
Benefits and Benefit vs. Cost Summary

Lynden Substation Project Benefits													
		Benefits											Cost
Alternative	Description	New Bank #2 Trf	New 115 kV Breaker	Bank #1 Ckt Switcher	Substation Expansion	New Control House	Bank #1 Metalclad	Bank #2 Metalclad	Transformer Differential	Remote 12.5 kV Breaker Control	Improved Driveway Access	12.5 kV Bus Section Switch or Breaker	115 kV Aux Bus or Better	Estimated Cost:
1	Replace Bank #2 in place when required.	✓												N/A
2	Expanded substation with 115 kV Main Bus and 1 Metalclad Feeder	✓	✓	✓	✓	✓		✓		✓	✓	✓		$7-14 million
3	Expanded substation with 115 kV Main Bus and 2 Metalclad Feeders	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		$8-17 million
4	Expanded substation with 115 kV Ring Bus and 2 Metalclad Feeders	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	$12-27 million
5	New substation at new site with 115 kV Ring Bus and 2 Metalclad Feeders	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	$11-43 million
6	Hybrid: Remove transformer, perform DER measures and do reduced scope of work in existing substation fence.	Not Needed	✓	✓	Not Needed	✓	✓	✓	✓	✓		Not Needed		$20-42 million

<u>Preferred Solution</u>

Even though the initial non-wires analysis suggested that there was an opportunity for cost-effective non-wires solution options for Lynden, a more detailed analysis indicated that a non-wires alternative will not be lower net cost than the traditional wires solution. The distinct characteristic of Lynden – a long-duration summer peak – meant that there were few incremental cost-effective DER available in PSE's portfolio that can address this peak. Without much capacity reduction from DER, the solution relies on a large-capacity battery, which is expensive relative to the traditional solution.

A staged approach can be used to make substation improvements efficiently. The preferred solution is for the substation be expanded within four years to address the aging infrastructure and operability issues before they affect customer reliability. At this point, the wired Alternative #3 would expand the substation, install a 115 kV circuit breaker for the BPA Bellingham-Lynden line, consolidate the control houses into one new control house, replace transformer Bank 2, replace both feeder structures to improve function, capacity and reliability, and improve operability by spreading out the equipment and relocating the driveway.

Alternatives will also be considered that would employ "non-wires" features that may be able to avoid some of the investment in traditional infrastructure. The hybrid options being developed would address both the N-0 capacity at the Lynden Substation and the N-1 capacity for the three-substation group that includes Lynden, Berthusen and Hannegan with only one transformer bank installed at the Lynden Substation. This three-substation group tends to achieve peak load in the summer due to agricultural operations in the region, which presents the opportunity to consider solar photovoltaics as part of the hybrid alternative in addition to energy storage and distributed energy resources.

CURRENT STATUS. This solution is in the final approval stage. Once approved it will move to the implementation phase for detailed design and permitting.

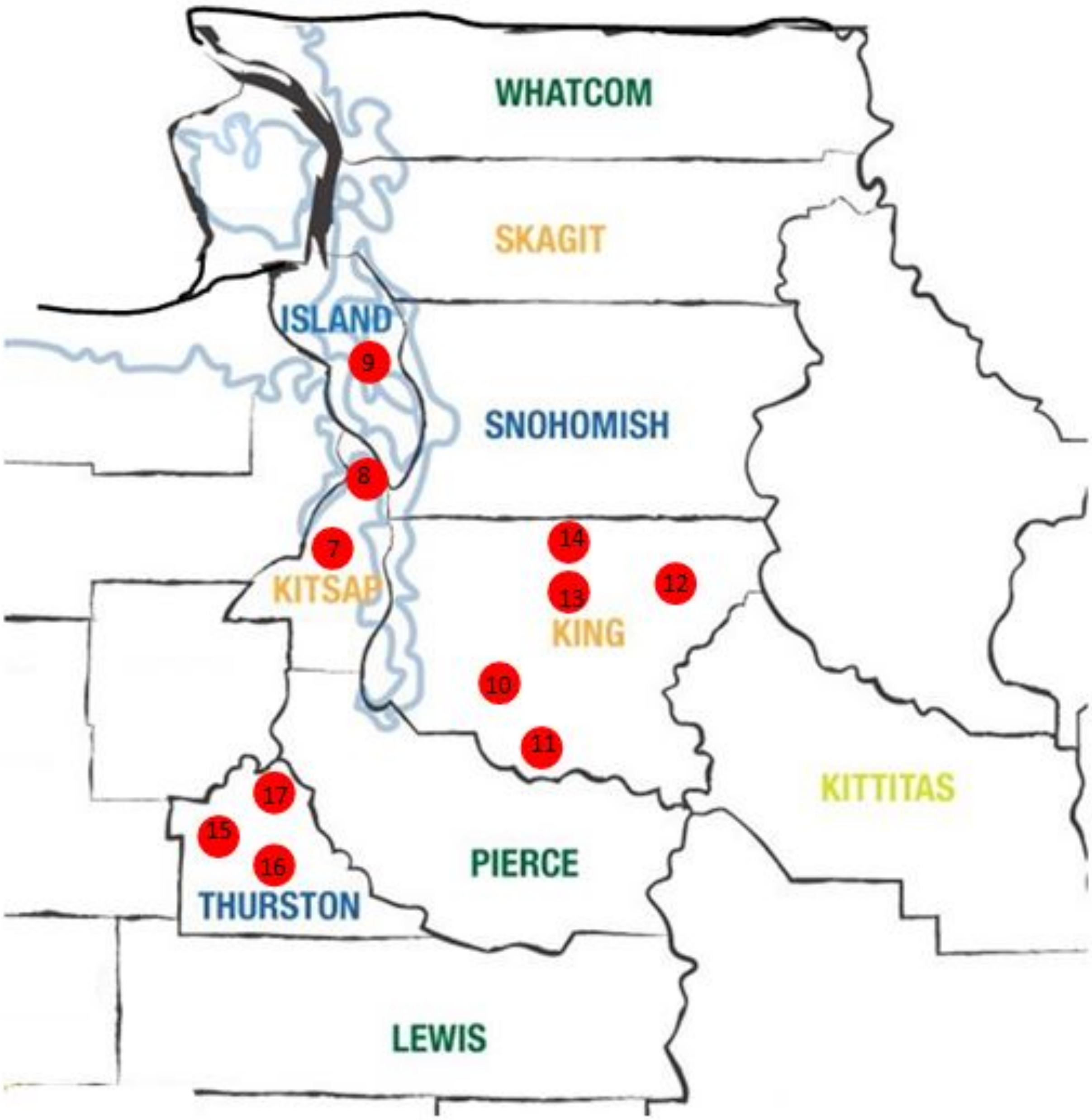
Major Electric Projects in Initiation Phase

The following projects are in the initiation phase, which includes determining need, identifying alternatives and proposing and selecting solutions. Among them are the Seabeck and West Kitsap projects, the remaining two projects being used to test, enhance and develop the planning process for integrating non-wires solutions. Based on learnings from the Bainbridge Island and Lynden assessments described in the project implementation section, as well as the Seabeck and West Kitsap projects, the non-wires analysis process has been initiated on additional projects, and a comprehensive study plan has been created to address known system needs going forward using the same approach. Based on the non-wire analysis screening criteria specific projects have been identified as suitable NWA candidates to further evaluate non-wire alternatives.

Figure M-14: Summary of 10-Year Major Electric Initiation Projects

SUMMARY OF MAJOR ELECTRIC PROJECTS IN INITIATION	DATE NEEDED	NEED DRIVER
7. Seabeck (NWA Pilot)	Existing	Capacity & Reliability
8. West Kitsap Transmission Project (NWA Pilot)	Existing	Capacity, Operational Flexibility & Aging Infrastructure
9. Whidbey Island Transmission Improvements	Existing	Aging Infrastructure, Reliability, Capacity, and Operational Concerns
10. Kent / Tukwila New Substation (NWA Candidate)	2020	Capacity & Aging Infrastructure
11. Black Diamond Area New Substation	2020	Capacity & Reliability
12. Issaquah Area New Substation (NWA Candidate)	Existing	Capacity
13. Bellevue Area New Substation	2021	Capacity & Reliability
14. Inglewood – Juanita Capacity Project (NWA Candidate)	2024	Capacity & Reliability
15. Spurgeon Creek Transmission Substation Development (Phase 2) (NWA Candidate)	Existing	Capacity & Reliability
16. Electron Heights - Yelm Transmission Project	2024	Capacity & Aging Infrastructure
17. Lacey Hawks Prairie (NWA Candidate)	2021	Capacity & Reliability

Figure M-15: Electric Planned Projects in Initiation Phase



7. Seabeck (NWA Analysis Pilot)

Estimated Need Date: Existing Need

Date Need Identified: 2019

The Seabeck area in Kitsap County serves 4,700 customers from two feeders through two substations and two transmission lines.

NEED ASSESSMENT. PSE begins studying an area when certain study triggers occur based on the system health, operations, load growth projections and other information that surfaces. Data is gathered and assumptions are made as followed.

<u>Planning Study Triggers</u>

- Feeder Capacity – When the loads in an area reach approximately 83 percent of existing capacity for both overhead (OH) and underground (UG) feeder sections under N-0 system operating conditions.
- Substation Capacity – When the loads in an area reach approximately 85 percent of existing station capacity for a study group of three or more substations to maintain operational flexibility.

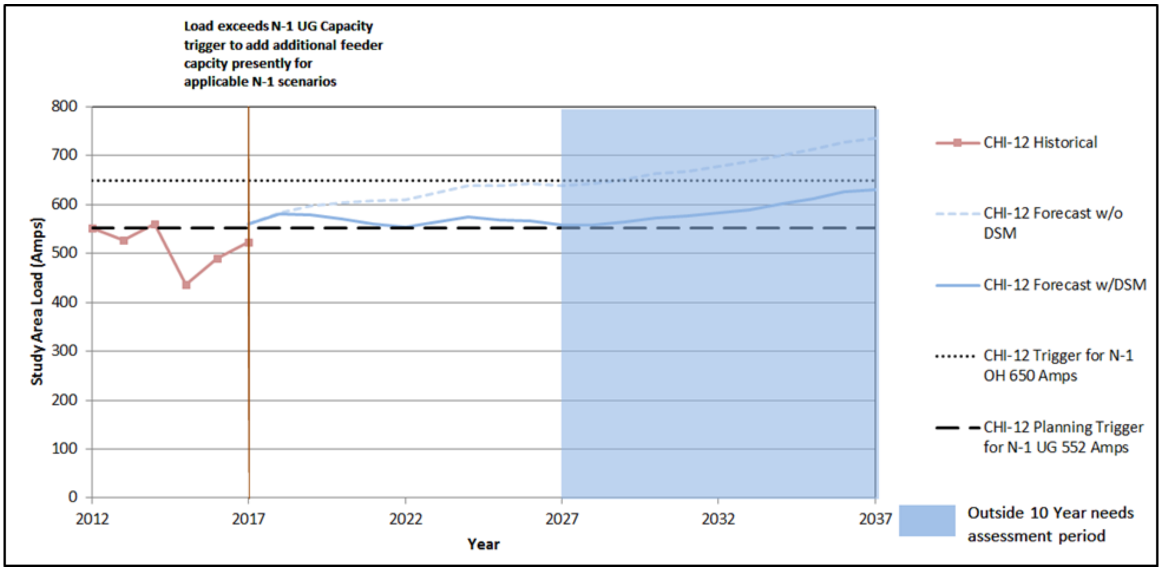
<u>Data and Assumptions</u>

- The assessment horizon selected was the ten-year period from 2018 through 2037.
- Historical five-year outage data are used in the assessment.
- There are no PSE DERs (distributed energy resources) on the feeders.
- There is 134 kW of interconnected net metering generation capacity on Chico substation on feeders CHI-12 79 kW, CHI-13 32 kW, CHI-15 5 kW, CHI-16 18 kW.
- There is 248 kW of interconnected net metering generation capacity on Silverdale substation on feeders SIL-13 73 kW, SIL-15 106 kW, SIL-16 69 kW.
- Normal Winter F2018 load forecast with 100 percent conservation.

NEEDS IDENTIFIED. The needs drivers identified are capacity and reliability.

<u>Capacity</u>: There are feeder capacity needs for distribution circuits CHI-12 and SIL-15. Both circuits are above the Distribution Planning Guidelines of 83 percent utilization of capacity under normal system configuration for current peak loading levels. CHI-12 is over 100 percent utilization under the contingent loading event of a step-up transformer failure for current peak loading levels. Figure M-16 illustrates historical demand, projected demand and the N-1 anticipated capacity need during the 10-year study period for CHI-12.

Figure M-16: CHI-12 N-1 Feeder Loading and Capacity



Feeder circuit CHI-12 has also experienced large phase imbalances at system peak during the past five years that are greater than planning guidelines allow (100 amps between any two phases). In 2017, at system peak, the difference between A and B phases was above 100 Amps for 60 hours with a peak imbalance of 124 Amps: Phase A averaged 657 Amps, B averaged 443 Amps and C averaged 401 Amps. In early January 2017, some single phase laterals were transferred from phase A to C. Year 2017 hourly PI data showed a maximum of 126 Amps imbalance between A and C. The resulting 126 Amp imbalance is above planning criteria of 100 Amps.

Reliability: There are also reliability concerns with circuits CHI-12 and SIL-15. Both are on PSE's worst-performing circuit list. These two circuits serve the entire load in this area and continue to have SAIDI and SAIFI scores significantly worse than average.

- Reduction of 220,000 CMI is needed on CHI-12 after completion of planned Distribution Automation (DA) project CMI Performance (2013-2015). The primary driver for CHI-12 is the 3-year non-MED CMI greater than 3 million minutes.
- Figure M-17 illustrates the CMI reliability metric for the Seabeck area which shows for both circuits well more than an average of 500,000 CMI minutes per year which is an indicator of poor performance.

Figure M-17: Seabeck Area Reliability Performance

Non-MED CMI (IEEE, T_{MED} adj for catastrophic storm), Minutes				
Circuit	**2013**	**2014**	**2015**	**Total (2013-2015)**
CHI-12	390,482	4,647,138	2,183,190	7,220,810
SIL-15	553,718	505,098	2,104,432	3,163,248

SOLUTION ASSESSMENT. Solution criteria includes technical and non-technical criteria as follows. PSE developed solutions criteria for system performance in the areas of capacity, reliability, asset life and constructability.

Technical Solution Criteria

- Must meet normal Winter 2018 load forecast with 100 percent conservation
- Must meet distribution planning standards and guidelines
- Must result in ≤ 100 percent of individual substation utilization
- Must result in ≤ 100 percent of overhead individual feeder limits for N-0 and applicable N-1 scenarios
- Must result in ≤ 100 percent of underground individual feeder limits for N-0 and applicable N-1 scenarios
- Must address all relevant PSE equipment violations
- Must not cause adverse impacts to the reliability or operating characteristics of PSE's or surrounding systems
- Must meet performance criteria for 10 years or more after construction

Non-technical Solution Criteria

- Environmentally acceptable to PSE and the communities it serves
- Constructible by the winter of 2021
- Utilize proven technology that can be controlled and operated using existing systems

Evaluation of Solution Alternatives

PSE studied conventional wires alternatives and determined the top wires alternatives to include (as shown in Figure M-18):

- WA-1: Build a new 115kV-12kV distribution substation near Seabeck.
- WA-2: Build a new 35kV-12kV distribution substation near Seabeck.
- WA-3: Install a third parallel step-up transformer at Chico substation.
- WA-4: Install a new express feeder from Chico substation to segment the existing feeder.

Figure M-18: Four Seabeck Wires Alternatives

		WA-1 Scope	WA-2 Scope	WA-3 Scope	WA-4 Scope
Needs	CHI-12 N-1 Capacity	Solved through new substation	New 35kV substation	Third parallel step-up transformer	New CHI-14 circuit taking
	CHI-12 Distribution Feeder Reliability	Improved through transmission restoration priority and spreading customers to multiple feeders	Improved through sub transmission restoration priority and spreading customers to multiple feeders	Improved through protection to multiple sub feeders. Mainline is hardened with tree wire	Improved through express underground feeder and creating sub feeders. Some customers transferred to new circuit
	SIL-15 Distribution Feeder Reliability	Improves SIL-15 CMI by placing some customers on a new circuit	Improves SIL-15 CMI by placing some customers on a new circuit	Does not reduce SIL-15 CMI	Improves SIL-15 CMI by placing some customers on new circuit
	Low Voltage	Solved through shorter feeders and more balanced circuits	Solved through LTC at new 35kV substation and sub placed closer to load center	Solved through addition of regulators and reduced load imbalance	Solved through reduction of load on CHI-12 and SIL-15 and reduced load imbalance
	CHI-12 Phase Balance	Phase imbalance will be reduced to less than 100 Amps per feeder. More opportunities to balance load.	Phase imbalance will be reduced to less than 100 Amps per feeder. More opportunities to balance load.	Phase balancing will need to be performed	Phase imbalance will be reduced to less than 100 Amps per feeder. More opportunities to balance load.
Decision Factors	Additional Costs - Land (ROW, Property)	Sub. property available, Public ROW	Public ROW	Public ROW	Public ROW + CHI-14 getaway route, New step-up transformer location
	Total Baseline Cost Estimate	$29.8 M	$19.5M	$12.5 M	$11.3M
	Reliability Benefits	High	Moderate	Moderate	High
	Benefits	Highest reliability improvement, eliminates most 35kV, increases operational flexibility	Improves reliability, increases operational flexibility	Improves reliability, increases operational flexibility	Improves reliability, eliminates 35kV exposure, increases operational flexibility
	Drawbacks	High Cost	High Cost	35 KV remains, no improvement to SIL-15 CMI	Some 35kV remains
	Risks	Public opposition to new substation and T-Line	Public opposition to new substation	Permitting challenges	Permitting challenges
	B/C Ratio	1.22	2.02	2.36	3.27
	Overall Preference	Lowest due to cost	3rd	2nd	1st - Highest benefit/cost ratio

After PSE developed conventional wires alternatives, Navigant was contracted to review these alternatives, analyze non-wire alternatives, and analyze hybrid solutions consisting of both wires and non-wires alternatives. The goal of this analysis was to consider the technical and economic feasibility of potential alternatives that could meet the Seabeck area needs. It was found that phase balancing would be best addressed using conventional methods, so a non-wires solution was not feasible. A hybrid solution composed of both wires and non-wires elements is a cost-effective and technically feasible solution. Ultimately two solutions were considered, a wired solution and a hybrid solution, as outlined in Figure M-19 below. As noted in the table, the non-wires solution did not meet the needs of the area.

Figure M-19: Three Seabeck Solution Alternatives

		Top Wires Alternative	Top Non-Wires Alternative	Top Hybrid Alternative
Needs	CHI-12 N-1 Capacity	Solved through new feeder	Solved through energy storage and DER	Solved through energy storage and DER
	Distribution Feeder Reliability	Improved by reduced tree/vegetation outage exposure and allowing more effective automation, while reducing the number of customers exposed to each outage	Distribution reliability is not addressed in the full non-wire alternative	Improved by reduced tree/vegetation outage exposure and allowing more effective automation
	CHI-12 Phase Balance	Phase imbalance will be spread throughout feeders, reducing to less than 100 Amps per feeder. More opportunities to balance load.	Phase Balance is not addressed in full non-wires alternative	Phase imbalance will be spread throughout feeders, reducing to less than 100 Amps per feeder. More opportunities to balance load.
	Low Voltage	Reduced loading and express 35kV circuit solves low voltage areas	Reduced loading solves voltage issues	Reduced loading and UG conversion solves voltage issues
Decision Factors	Total Cost Estimate Range (Base to High)	$11.3 million to $14 million	$4.6 million to $6.5 million	$16.1 million to $19.6 million
	Benefits	10-year solution. Highest reliability benefit. Added capacity. Increased operational flexibility.	10 year solution. Local EE and DR	10-year solution. Improved reliability.[6] Local EE and DR.
	Risks	Easement and permitting challenges for new construction	No reliability improvement. Easement and permitting challenges for BESS site. New operational strategies needed. Need additional improvements with growth	Easement and permitting challenges for BESS site. New operational strategies needed. Need additional improvements with growth

CURRENT STATUS. PSE has performed a cost comparison for all viable solutions. The preferred solution is the top wired alternative which was selected based on cost, benefits, drawbacks, risks and benefit-to-cost ratio.

6 / Navigant has identified islanding as a potential additional reliability benefit of the hybrid alternative, however this would require additional studies and operational changes within PSE.

8. West Kitsap Transmission Improvement (NWA Analysis Pilot)

Estimated Need Date: Existing Need

Date Need Identified: 2018

The West Kitsap area includes Port Orchard, Bremerton, Poulsbo and Bainbridge Island and serves 122,000 customers from 28 substations and 18 transmission lines.

NEED ASSESSMENT. PSE begins studying an area when certain study triggers occur based on the system health, operations, load growth projections and other information that surfaces. Data is gathered and assumptions are made as followed.

Planning Study Triggers

- Capacity need
- Voltage collapse conditions
- Transmission reliability
- Aging infrastructure

Data and Assumptions

- The study analyzed the Kitsap Peninsula transmission system over a planning horizon of 10 years (2018 to 2027).
- The 2017 PSE Load Forecast was utilized to project native PSE load in Kitsap County – with 100 percent conservation.
- There are two non-PSE major loads on the Kitsap Peninsula – U.S. Naval Base Kitsap and the U.S. Navy Puget Sound Naval Shipyard (PSNS). The load levels for these two non-PSE major loads were taken from the WECC power flow models.
- The transmission system assessment was conducted in accordance with the NERC and WECC Transmission Planning Standards (TPL-001-4, TPL-001-WECC-CRT-3) and PSE Transmission Planning Guidelines.
- Transmission contingency studies focused on the BPA transmission supply system out of BPA's Shelton substation and PSE's transmission facilities located within Kitsap County.
- Generation dispatch patterns and Northern Intertie transfers were maintained the same as in the WECC base cases, as they have no significant impact on the Kitsap Peninsula transmission system.
- There are no utility-scale generation resources within Kitsap County. There are distributed energy resources connected behind the meter, and those are included in the loads.

- There are no transportation loads for PSE in Kitsap County; however, the study model includes transportation loads in other counties. The power flow base cases modeled PSE transportation load as observed during 2017, i.e., summer transportation load of 238 MW and winter transportation load of 262 MW.

NEEDS IDENTIFIED. The analysis determined that there are capacity, thermal and voltage needs over the next 10 years on the transmission system, plus operating flexibility, aging infrastructure and reliability concerns.

Capacity. The existing 230 kV supply system to Kitsap Peninsula lacks capacity under multiple contingency scenarios (N-1-1, N-2 or bus contingencies) in supplying the forecasted Kitsap Peninsula load over the 10-year planning horizon (2018-2027). Certain multiple contingencies result in a voltage collapse on the peninsula. In 2018, eight 115 kV transmission lines located in central and northern Kitsap Peninsula exceeded their emergency limits for N-1-1 conditions during the winter and summer peak conditions.

Operating Flexibility. The 115 kV transmission system on Kitsap Peninsula is capacity constrained under N-1-1 scenarios during winter. This creates operating flexibility concerns while scheduling outages for planned and unplanned maintenance on the transmission system during winter. Typical corrective action to prevent N-1-1 overloads includes opening the transmission network to make transmission lines radial, which reduces reliability and increases the risk of the transmission outages.

Aging Infrastructure. BPA's two 230 kV bulk transformers feeding PSE's Kitsap Peninsula load are nearing the end of their useful life at 40 and 56 years of age. Loss of a bulk transformer and the long time-frame required to replace it with a spare (approximately a month) puts PSE's Kitsap load at risk of a large outage or voltage collapse for the next major contingency during peak winter conditions. PSE's 115 kV Vashon submarine cables are 56 years of age and have had numerous operational issues.

SOLUTION ASSESSMENT. Solution criteria includes technical and non-technical criteria as follows. PSE developed solutions criteria for system performance in the areas of capacity, reliability, asset life and constructability.

Technical Solution Criteria

- Must meet all performance criteria for transmission and distribution
- Must address all relevant PSE equipment violations identified in the Needs Assessment
- Must address all relevant needs identified in the Needs Assessment Report
- Must not cause any adverse impacts to the reliability or operating characteristics of PSE's or surrounding systems
- Must not re-trigger any of the needs identified in the Needs Assessment for 10 years or more after the project is in service

Non-technical Solution Criteria

- Environmentally acceptable to PSE and the communities it serves
- Constructible by the winter of 2029
- Utilize proven technology which can be controlled and operated using existing systems
- Reasonable project cost

Evaluation of Solution Alternatives

PSE planners are developing multiple wires solutions to solve the area's needs in order to compare them with non-wires solutions comprised of distributed energy resources and utility-scale energy storage systems. At this time, one of the wired alternatives is being used as a reference for the non-wires analysis. Additional wired alternatives are being developed, and a final proposed solution is yet to be determined.

The Kitsap Peninsula needs are so great that the peninsula load would need to be reduced by more than 30 percent in the near term to reduce all N-1-1 thermal overload and voltage collapse conditions. As a result, an energy storage system comparable to the largest ever built would be required to entirely eliminate the need for a conventional wires solution. In addition, the non-wires expert consultants on the project team estimated that a full non-wires alternative would be many times more expensive than the wires solution. Once it was determined that a full non-wires solution was not practical technically or economically, hybrid solutions were considered.

The wired components considered in the hybrid solutions varied slightly, but consistently included the bulk system elements necessary to prevent voltage collapse. Energy storage and distributed energy resources were analyzed for their ability to prevent overloads. To meet portions of the capacity needs, alternatives including exclusively energy storage or combinations of energy storage and distributed energy resources were considered. However, while there is some potential to reduce the size of the energy storage for hybrid solutions (compared to a full non-wires solution), the net costs are still much higher than the estimated conventional solution costs. There are many winter hours that exceed the capacity threshold, and these longer duration needs are more expensive to meet with battery storage or distributed energy.

Preferred Solution: The preferred solution is to continue development of a full wires solution. Given the complexity of the wires solutions, work will continue on refining the preferred solution developed initially that involves the installation of multiple segments of 115 kV transmission lines between BPA Kitsap/South Bremerton and Valley Junction. The final step of the multi-year plan is to add a 230-115 kV transformer capacity in Kitsap County. The non-wires studies prepared for PSE by the consultants will be referenced as the wires solution is finalized, but at this time the overall conclusion is not expected to shift materially. Deconstructing the needs and potential solutions for a complex transmission system with significant needs required a very high level of effort by the project team (both PSE staff and the consultants), and the experience provided PSE with a sense of the demanding analysis required and the feasibility of meeting such transmission needs with non-wires alternatives.

CURRENT STATUS. Completion of the wired alternatives analysis is expected by Q1 of 2021. Stakeholder engagement will be determined after the recommended solution becomes available.

9. Whidbey Island Transmission Improvements

Estimated Need Date: Existing
Date need identified: 2018

Whidbey Island serves 38,000 customers out of 12 substations and two transmission lines.

PROJECT NEED. The need drivers for this area are aging infrastructure, reliability, capacity and operational concerns.

Aging Infrastructure: Replacement of aging infrastructure is an immediate need. Two 115 kV oil-filled circuit breakers need to be replaced at Whidbey Substation due to age and outdated technology. The distribution transformer at Faber Substation was installed in 1968 and is being monitored due to the presence of water in the oil. Plans are under way to replace this transformer with a 25 MVA load tap changing transformer in the future.

Reliability: The main bus design at Whidbey Substation does not allow for breaker maintenance without a line outage and has a possibility of substation outages south of Whidbey due to a bus or breaker fault.

Capacity: A capacity concern beginning in 2026 includes transmission line ratings that are significantly limited due to low ratings of the older circuit breaker CTs.

Operational Concerns: There are over and under voltage concerns outside the standard range of 116 V – 126 V on certain sections of the feeders on the island.

CURRENT STATUS. The needs assessment has been completed and the study process for both traditional wires solutions and non-wire alternatives will be undertaken in 2021.

10. Kent/Tukwila New Substation (NWA Candidate)

Estimated Need Date: 2020
Date need identified: 2018

The Kent-Tukwila area serves 20,300 customers from 12 substations and four 115 kV transmission lines. The area is expected to experience heavy growth in the next 20 years.

PROJECT NEED. The need drivers for this area are capacity and aging infrastructure.

Capacity: 2018 NERC TPL studies showed that different combinations of P6 contingencies (N-1-1) resulted in the potential for thermal overloads during summer and winter peak conditions starting in 2024. Additional development occurring in the area (including redevelopment of industrial areas) has resulted in the need for additional substation and distribution system capacity to serve growing demand. The additional loads also exacerbate the NERC Compliance issues listed above.

Aging Infrastructure: Replacement of aging infrastructure is an immediate need. The 115 kV underground transmission line that provides transmission service in the area was installed in 1974 and is currently beyond its expected service lifetime. Loss of transmission support from the cable would negatively impact reliable service to customers in the area.

CURRENT STATUS. The study process for traditional solutions is underway. The study has not progressed enough to propose solutions. Project initiation to review alternatives is expected to be finalized in 2021.

11. Black Diamond Area New Substation

Estimated Need Date: 2020
Date Need Identified: 2019

The Covington/Black Diamond area serves 17,500 customers from six substations and one 115 kV transmission line. The area is expected to experience heavy load growth in the next 20 years.

PROJECT NEED. The need drivers for this area are capacity and reliability.

Capacity: Several large developments in the area will result in the need for additional distribution capacity. This capacity will need to come from additional transmission substations in order to serve the load reliably and meet future needs.

Reliability**:** A single 115 kV transmission line serves this area. The transmission system will need additional reinforcements to ensure that reliability is not reduced if additional substations and distribution transformers are added to the existing equipment.

CURRENT STATUS. The study process for traditional solutions is underway. The study has not progressed enough to propose solutions. Project initiation for review of alternatives is expected to be finalized in 2021.

12. Issaquah Area New Substation (NWA Candidate)

Estimated Need Date: 2021
Date Need Identified: 2019

The Issaquah area distribution feeders serve 23,000 customers in downtown Issaquah, Klahanie and the Highlands area from four substations with four transmission lines. The area is expected to experience more growth in the near future.

PROJECT NEED. The need driver for this area is capacity.

Capacity. Between 2020 and 2021, the predicted load increases will reduce operational flexibility for the feeder group in the Issaquah Highlands area and exceed the planning trigger for adding additional feeder capacity. Between 2023 and 2025, the area will have insufficient feeder capacity to serve additional load. In 2018, with the operating scenario of having one feeder out of service (N-1), capacity was already exceeded. This has resulted in lengthier outages, as the ability to pick up customers during a feeder outage contingency is limited.

CURRENT STATUS. Preferred wires solutions are expected to be identified at end of 2020. The two expected options are expanding Pickering substation to two banks (requires an additional transmission line) or interconnect a new 230 kV at Grandridge site to BPA. The traditional solutions should be identified by end of 2020 and non-wires solutions by the end of March 2021. Then project initiation will be able to review the alternatives.

13. Bellevue Area New Substation

Estimated Need Date: 2021

Date Need Identified: 2018

The downtown Bellevue, Redmond and Kirkland area serves 21,000 customers from 8 substations and three 115 kV transmission lines. The area is expected to experience more growth in the near future.

PROJECT NEED. The need drivers for this project are reliability and distribution capacity.

Reliability: Bellevue and Kirkland have a high percentage of commercial, industrial and high-rise residential customers in the downtown core. For a planned outage followed by an unplanned outage during peak summer or winter loading on either of these lines, a significant amount of residential and commercial load will be at risk.

Capacity**:** Load growth from the new Sound Transit and Spring District exceeds the capacity of the distribution system.

CURRENT STATUS. The detailed Needs Assessment is complete. The study process for traditional solutions will start in 2020. Traditional solutions should be identified by the end of March 2021 and non-wires solutions by the end of June 2021. At that time, project initiation will be able to review the alternatives.

14. Inglewood – Juanita Capacity Project (NWA Candidate)

Estimated Need Date: 2024

Date Need Identified: 2019

With the completion of the Sammamish – Juanita project (Project 1 in the Planned Projects discussion above), the Inglewood – Juanita line will be one of three transmission lines that serves 40,000 customers from eight substations in the Kirkland, Kenmore and Bothell areas.

PROJECT NEED. The need drivers for this area are capacity and reliability.

Capacity: 2018 NERC TPL studies indicate thermal overloads for P6 contingencies (N-1-1) during the summer 2024 time period. The same overload is predicted during both the winter and summer 2028 time periods.

Reliability**:** The potential increased load along with the potential for additional distribution transformation and capacity requires transmission infrastructure upgrades to maintain reliability for customers.

CURRENT STATUS. Project initiation to review alternatives is expected in 2022.

15. Spurgeon Creek Transmission Substation Development (Phase 2) – (NWA Candidate)

Estimated Need Date: Existing Need
Date Need Identified: 2019

The Thurston County South region is primarily served by one extra high voltage source and one 115 kV transmission line connecting to the Pierce County grid. The cities of Tenino and Yelm, which are in the South region, have approximately 19,000 customers served by five substations and two transmission line sources.

PROJECT NEED. The need drivers for this area are capacity and reliability.

Capacity: A transmission capacity need currently exists under certain N-1-1 transmission contingencies that result in thermal overloads of the bulk power supply source into the Olympia area. A distribution capacity need may also be present at a substation due to estimated load growth, and an additional distribution transformer bank will require the transmission line to be looped into the radially fed substation, providing a second source to the station.

Reliability: Two reliability improvements are required: 1) a new bulk power source supply into South Thurston County, and 2) additional transmission lines to interconnect the North and South regions of Thurston County.

CURRENT STATUS. The detailed Needs Assessment is underway. The transmission and distribution needs are identified. The study process for traditional solutions will start in 2021. Project initiation to review alternatives is expected in 2021.

16. Electron Heights - Yelm Transmission

Estimated Need Date: 2024
Date Need Identified: 2019

The Tenino/Yelm area serves approximately 19,000 customers from five substations and two transmission sources.

PROJECT NEED. The need drivers for this area are capacity, reliability and aging infrastructure.

Capacity. Greater transmission capacity is needed to resolve line overloads on the Electron Heights-Yelm 115 kV line and low voltage conditions under multiple contingencies (N-1-1) in the area. A significant portion of the line is 4/0 Cu low-capacity conductor, which limits the throughput of the line.

Reliability. Customers are at risk of outages under N-1-1 conditions. The need will be met by the Electron Heights – Enumclaw 55-115 kV Conversion that is expected to be complete in 2022, which may delay the need for this project past the 10-year planning horizon.

Aging Infrastructure. The wishbone cross-arm construction has reached the end of its useful life and poses an outage risk due to failure.

CURRENT STATUS. The detailed Needs Assessment and project initiation to review alternatives is expected to start in 2022.

17. Lacey Hawks Prairie Capacity (NWA Candidate)

Estimated Need Date: 2022
Date Need Identified: 2018

The Lacey Hawks Prairie area serves approximately 13,000 customers from three substations and six transmission sources.

PROJECT NEED. The need driver for this area is capacity

Capacity. Greater distribution substation and feeder capacity is needed to maintain operational flexibility and serve developing load.

Reliability. The customer base is at risk of outages under N-1-1 conditions.

CURRENT STATUS. The detailed Needs Assessment and Project initiation to review alternatives is expected to start in 2021.

Additional Capacity Growth Areas in Initiation Phase

Additional growth areas throughout PSE's service territory are being tracked and studied. These areas experience local growth that will exceed our transmission and distribution capacity limits within a 10-year timeframe. All of these are expected to pass the non-wire alternative screening criteria and be considered candidates for non-wire alternatives.

Figure M-20: Additional 10-Year Capacity Growth Areas

ADDITIONAL CAPACITY GROWTH AREA NEEDS IN INITIATION	DATE NEEDED	NEED DRIVER
Sumner Valley Area (NWA Candidate)	2024	Capacity
Federal Way Area (NWA Candidate)	2024	Capacity & Reliability
Covington Area (NWA Candidate)	2027	Capacity
East Whatcom Area (NWA Candidate)	2026	Capacity
Redmond/Duvall Area (NWA Candidate)	2028	Capacity
Kent/Auburn Area (NWA Candidate)	2030	Capacity
Skagit County Area (Potential NWA Candidate)	2030+	Capacity
Puyallup Area (Potential NWA Candidate)	2030+	Capacity

3. NATURAL GAS DELIVERY SYSTEM

Existing Natural Gas Delivery System

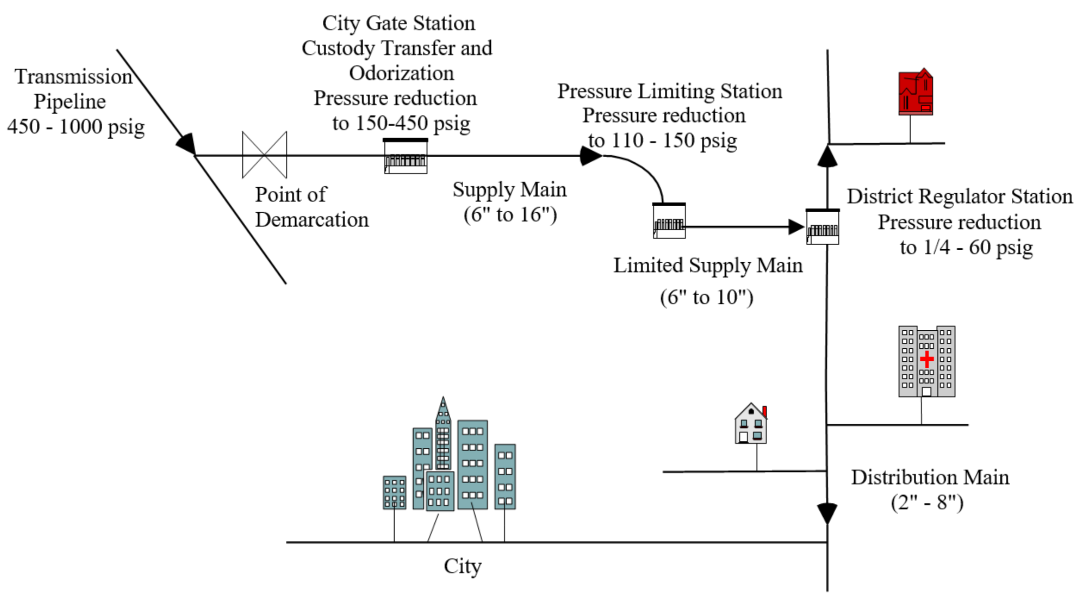
The table below summarizes PSE's existing gas delivery infrastructure as of December 31, 2020. Natural gas delivery is accomplished by means of pipes and pressure regulating stations.

Figure M-21: PSE-owned Natural Gas Distribution System as of December 31, 2020

PSE – OWNED NATURAL GAS DISTRIBUTION SYSTEM AT 12/31/20
Customers: 866,788
Service area: 2,520 square miles
City gate stations: 42
Pressure regulating stations: 560
Miles of pipeline: 13,282
Supply system pressure: 150–550 psig
Distribution pipeline pressure: 45–60 psig
Customer meter pressure: 0.25 psig

How the Natural Gas Delivery System Works

Figure M-22: Illustration of Natural Gas Delivery System



Natural gas is transported at a variety of pressures through pipes of various sizes. Interstate transmission pipelines deliver gas under high pressures (generally 450 to 1,000 pounds per square inch gauge [psig]) to city gate stations. City gate stations reduce pressure to between 150 and 450 psig for travel through supply main pipelines. Then district regulator stations reduce pressure to less than 60 psig. From this point gas flows through a network of piping (mains and services) to a meter assembly at the customer's site where pressure is reduced to what is appropriate for the operation of the customer's equipment (0.25 psig for a stove or furnace), and the gas is metered to determine how much is used.

The natural gas system was first built in the late 1800s, expanding in a networked, two-way flow design. Pipeline materials and operating pressures have changed over time. Natural gas was introduced to the Puget Sound region in 1956, allowing for higher pressures and smaller diameter pipes. Where older cast iron pipe was used, new plastic pipe is inserted into it as a way of cost effectively renewing existing infrastructure in urban areas. While the energy qualities and pipeline materials have changed, the technology used to operate the system has not. Because natural gas pipelines are often located within increasingly congested rights-of-way, protecting pipelines from damage is even more important.

10-Year Natural Gas Delivery System Plan

The natural gas resource planning process focuses on conservation and demand-side resources and the future of low-carbon alternative fuels. In the next decade, PSE will modernize the natural gas system to:

- reduce greenhouse gas emissions
- ensure pipeline safety
- address major backbone infrastructure needs

The modernization of the natural gas system and focus on pipeline safety will provide more opportunities for programs such as demand response and position the pipeline system to become agnostic to fuel type over time as alternative fuel supply chains mature, supply increases and costs decrease.

The 10-year natural gas infrastructure plan includes key investments in the areas of visibility, analysis and control; reducing greenhouse gas emissions; pipeline safety and reliability; and addressing backbone infrastructure needs. Figure M-23 summarizes the major elements of the plan. Discussion of the key investment areas in the following pages highlights the fact that these investment areas are interrelated. The 10-year plan addresses needs that are either existing or predicted based on the processes described in Chapter 9, Natural Gas Analysis. Delivery system studies are performed every year which will surface new needs or constraints in future 10-year plans. In addition, the outer years of the plan may change substantially in this time of energy and load evolution. Like the IRP, this 10-year plan provides overall direction to inform decisions about specifically funded action and plans.

Figure M-23: Summary of 10-Year Natural Gas Delivery System Plan

10-YEAR NATURAL GAS DELIVERY SYSTEM PLAN SUMMARY	
VISIBILITY, ANALYSIS AND CONTROL	
Foundational Technology	Advance Metering Infrastructure (AMI)
Smart Equipment	Data and control technologies such as automated values and SCADA devices
REDUCE GREEN HOUSE GAS EMISSIONS	

Ongoing programmatic leak repair and operation practice modifications	New tools and operating procedures Upgraded high pressure and intermediate pressure distribution lines
Pilot Projects enable PSE to test the feasibility and effectiveness of new solutions to delivery system challenges.	Hydrogen and other lower carbon blending fuels
PIPELINE SAFETY AND RELIABILITY	
Ongoing programmatic replacements and upgrades to system components to address aging infrastructure and load increases to ensure reliable energy delivery.	Demand response, conservations, and time-of-use Upgraded high pressure and intermediate pressure distribution lines and regulation equipment 34 risk mitigation programs that include inspections and upgraded lines and equipment
SECURITY. CYBERSECURITY AND PRIVACY	
Ongoing security measures	Physical security of key assets Industry standards, protocols and requirements for technologies and vendors
ADDRESSING MAJOR BACKBONE INFRASTRUCTURE NEEDS	
Major backbone infrastructure projects are driven by capacity and reliability needs. These are discussed in detail starting on page M-57.	

Improving Visibility, Analysis and Control

ADVANCED METERING INFRASTRUCTURE (AMI). PSE is in year four of replacing the current aging and obsolete Automated Meter Reading (AMR) system and gas customer modules with Advanced Metering Infrastructure technology. AMI is an integrated system of smart modules, communications networks and data management systems that gives both PSE and its customers greater visibility into customer use and load information and enables two-way metering between PSE and its customers.

DATA AND CONTROL. PSE has modernized its monitoring tools, replacing manual field charts with digital equipment, and will continue to evaluate greater use of automated valves to provide control where needed.

Reducing Greenhouse Gas Emissions

ELIMINATING LEAKS AND METHANE RELEASE. PSE will continue to eliminate leaks from the natural gas system, eliminating all non-hazardous[7] leaks by 2022. PSE will evaluate operating practices and methods to further minimize methane releases, for example, by increasing contractor awareness when working around pipelines to prevent damage during construction, repairing leaks more quickly than regulations require, or capturing natural gas when construction work requires pipelines to be depressurized and purged.

CLEANER FUELS. PSE already integrates some renewable natural gas (RNG) into the delivery system to decrease carbon emissions, and PSE will continue to look for innovative ways to harvest more RNG. PSE has also begun to evaluate opportunities to partner in testing and learning how hydrogen can be blended into the natural gas system to reduce carbon emissions in ways that are similar to how bio-methane or waste-based renewable natural gas are blended with natural gas. This will prepare PSE to leverage the technology as supply increases, cost decreases and the technology matures.

Ensuring Pipeline Safety and Reliability

ENSURING A HEALTHY SYSTEM. To ensure overall reliability and safe operations, PSE expects to replace or upgrade the following system components in the next 10 years.

- Replace 200 to 300 miles of gas main (for example, DuPont pipelines that are prone to catastrophic failure).
- Continue PSE's industry leadership in mitigating sewer cross bores,[8]
- Remediate customer meter set equipment that has been buried.
- Deploy 34 programs to address pipeline safety risks associated with pipelines, pressure regulation equipment and meters.
- Invest more in risk mitigation programs pursuant to the recent passage of the Pipeline Reauthorization Act Rules.

7 / Hazardous leaks require immediate repair or repair within defined timeframes.
8 / Sewer cross bores occur when gas pipe, installed by bore technologies, crosses through unlocatable sewer pipes.

MANAGING INCREASING LOADS. With real possibilities to reduce carbon emissions by increasing use of renewable natural gas and blending alternative fuels such as hydrogen with natural gas, PSE will continue to address growth areas to meet customer choice expectations. PSE will also continue investigating demand response technologies that help offset increased loads as a result of customer growth**.** In 2018-2019, PSE piloted a natural gas demand response program to determine the potential for peak capacity reductions using smart thermostats. These pilot results will allow PSE to evaluate the potential for using gas demand response as a non-pipes alternative to delay supply and distribution investments. PSE will continue to build on its demand response experience to help determine what role this new tool can play in alternatives to pipeline infrastructure. Additionally, PSE will leverage demand-side resources through local programmatic reliable energy efficiency. As PSE pursues its time-of-use pilot, lessons will benefit local applications to manage loads and defer infrastructure investments.

PSE anticipates that leveraging energy-saving technologies will help address some local delivery system capacity constraints, but not all, due to the local characteristics of each area. In addition to the major natural gas backbone infrastructure described below, new or upgraded high pressure and intermediate pressure systems will be needed, along with upgrades to approximately 31 pressure regulation stations to serve load beyond what the existing stations capacity can serve.

Maintaining Strong Security, Cyber Security and Privacy

As critical infrastructure becomes more technologically complex, it is even more crucial for PSE to adapt and mature the physical security of key assets and cybersecurity practices and programs to make it possible to take advantage of new technical opportunities such as Internet of Things devices. To ensure risks are consistently addressed and mitigated in alignment with the rapidly changing security landscape, PSE utilizes a variety of industry standards to measure maturity as each standard approaches security from a different perspective. In addition, PSE fosters strong working relationships with technology vendors to ensure their approach to cybersecurity matches PSE's expectations and needs. PSE's telecommunications strategy will evolve to support required security and reliability, leveraging existing communication networks such as the AMI communication mesh network.

Major Backbone Infrastructure Projects

Major infrastructure projects are driven by increasing loads and reliability needs and proceed in two phases. The **initiation phase** includes the development of the need, evaluation of alternatives and identification of a proposed solution. The **implementation phase** includes project planning for which the need and proposed solution is tested, and then design, permitting and construction begins. Once a project is in implementation, location specific activities begin, including engagement with the local community. Informational updates are provided through the IRP process for projects in this phase. PSE is working to develop more detail and engagement with the IRP stakeholders when a project is in the initiation phase.

Lessons learned from the PSE demand response pilot support the IRP preferred portfolio that identifies the opportunity to meet increasing resource needs using conservation and demand-side management programs. Chapter 9, Natural Gas Analysis, discusses PSE's non-pipe alternative analysis process, and PSE will continue to screen new needs for non-pipe alternative potential in support of this forecast and refine data and tools as more is learned.

The specific project descriptions in the following pages are divided into the two phases described above. They include summaries of the need and solution identified for each project, as well as highlights for upcoming non-pipe alternative (NPA) analysis for two projects.

Major Natural Gas Projects in Implementation Phase

Figure M-24: Summary of 10-year Major Natural Gas Implementation Projects

SUMMARY OF MAJOR NATURAL GAS PROJECTS IN IMPLEMENTATION	EST. In SVC
1. Bonney Lake Reinforcement	VARIES
2. North Lacey Reinforcement	2022
3. Tolt Pipeline	2026

1. Bonney Lake Reinforcement

Estimated Need Date: Existing

Date Need Identified: 2019

The Bonney Lake area includes the Lake Tapps and South Prairie areas and a particularly large and growing customer development.

PROJECT NEED. Demand on PSE's natural gas supply system serving the Lake Tapps and Bonney Lake areas exceeded its capacity in 2017. Additionally, a large development being built in the southern end of the system, the Tehaleh development. The combination of existing demand, projected area growth and this new development exceeds the capacity of the existing high pressure lateral. For several years, PSE's ten-year plans have documented the necessary system improvements for the Bonney Lake area. PSE performs manual adjustments in two locations during cold weather along with 100 percent curtailments in order to maintain service at the end of the system. These actions will soon be insufficient to address the reliability concerns.

Figure M-25: Bonney Lake Area Capacity Need

Year Number	Winter Year Need	Total Additional Capacity Necessary in scfh (Cumulative)*	Yearly Capacity Increase (or decrease) Necessary in scfh*
1	2019-20	104,200	104,200
2	2020-21	139,900	35,700
3	2021-22	171,100	31,200
5	2023-24	234,100	63,000
10	2028-29	406,900	172,800
15	2033-34	571,500	164,600
20	2038-39	732,400	160,900

SOLUTION IMPLEMENTED. PSE is installing 12-inch high pressure pipeline parallel to the existing 6-inch high pressure pipeline for which capacity has been exceeded and a Gate Station to reinforce the natural gas supply to the Bonney Lake and Lake Tapps areas.

CURRENT STATUS. Phase 1 was completed in 2017, which included two miles of 12-inch line parallel to the existing 6-inch line. Phase 2 will be completed in 2022, which includes an additional two miles of new 12-inch line parallel to the existing 6-inch line. Future phases include additional high pressure pipeline and a new gate station.

2. North Lacey Reinforcement

Estimated Need Date: Existing
Date Need Identified: 2009

The North Lacey area includes Lacey and the north and east Olympia areas and serves approximately 21,000 customers. The project is intended to reinforce the Olympia system.

PROJECT NEED. Overall customer growth is increasing the demand on the existing system. The supply system needs reinforcement in order to serve recent and projected customer loads. The models are showing significant low pressure issues when pipeline restrictions are taken into account. The supply system is unable to meet minimum design requirements without manual operations. The downstream distribution system cannot maintain adequate system reliability when the upstream supply system is unable to maintain system reliability itself. Two cold weather actions (CWAs) are scheduled for this area along with 100 percent curtailments, and these actions will soon be insufficient to address the reliability concerns.

SOLUTION IMPLEMENTED. The preferred solution is a pipeline solution for the current and near-term need. It includes high pressure pipeline and may also include a limit station and a pressure increase. These projects will solve the capacity, pressure, CWA and reliability concerns and still allow for future expansion when and if it occurs.

CURRENT STATUS. Final completion of the long-term alternatives analysis is expected to be completed by the end of 2022.

3. Tolt Pipeline

Estimated Need Date: 2024

Date Need Identified: 2009

The greater Eastside area, from Bothell/Woodinville to Bellevue in King and Snohomish counties serves approximately 80,000 customers from the Duvall Gate Station.

PROJECT NEED. Growth will exceed the current Duvall gate station capacity in the winter of 2024-25, at which time a total station rebuild of Duvall gate station is required. The Duvall Lateral, which delivers gas from the Williams Interstate Pipeline at the Duvall gate station to the Woodinville, Bothell, Kenmore and Kirkland areas, will experience low pressures for 40 percent of its length during extreme cold weather events. On a design day, the area experiences a shortfall of 127,000 scfh.

SOLUTION IMPLEMENTED. Install 1.3 miles of 16-inch high pressure pipeline and a new gate station to loop and reinforce the existing supply system.

CURRENT STATUS. PSE completed Phase 1 of this project, installing 2.7 miles of 16-inch high pressure pipeline in 2015. Phase 2 will be completed in 2026, which includes a new gate station.

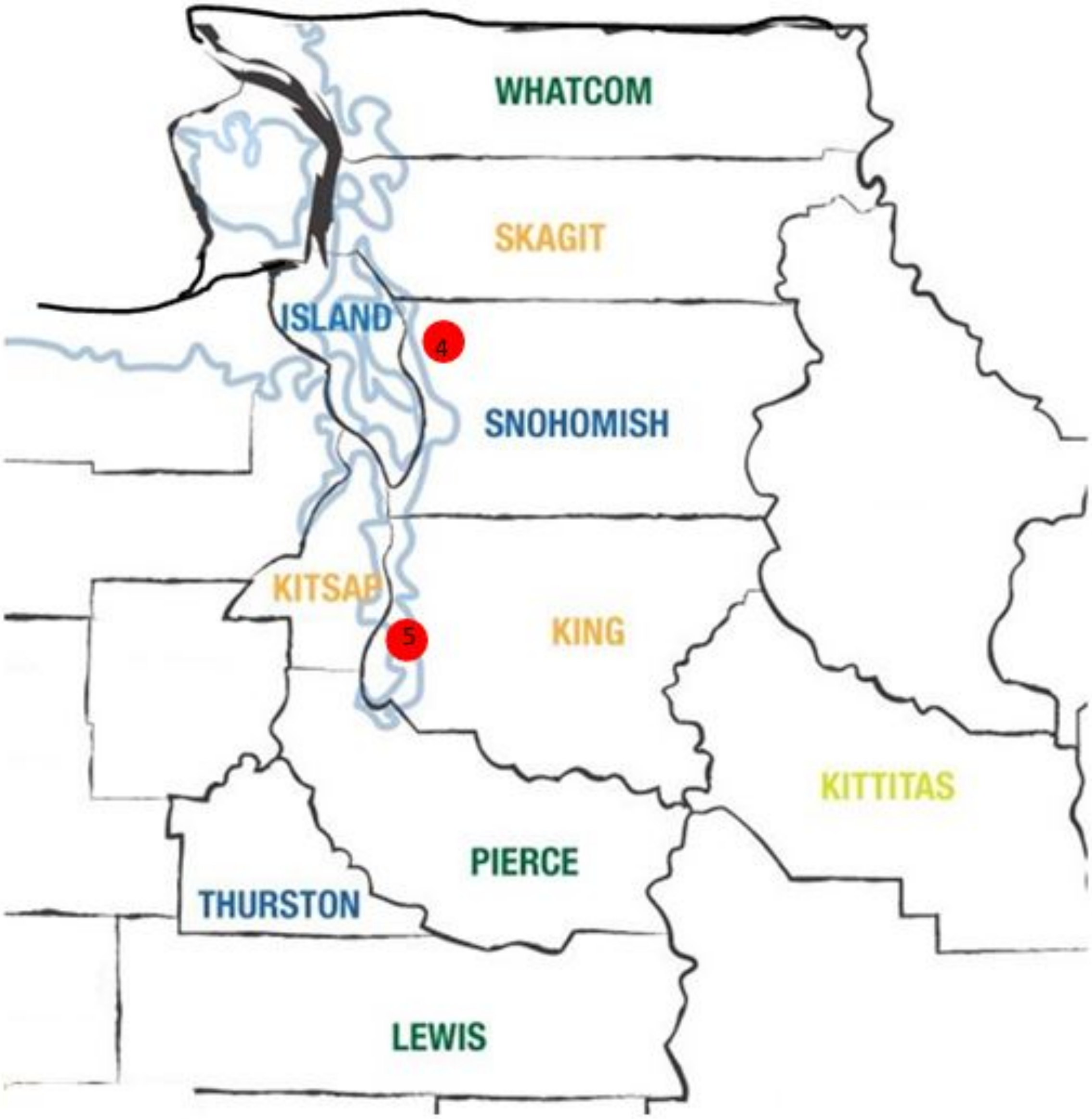
Major Natural Gas Projects in Initiation Phase

Figure M-26 summarizes the planned projects in the project initiation phase which includes determining need, identifying alternatives and proposing and selecting solutions.

Figure M-26: Summary of 10-year Major Natural Gas Initiation Projects

SUMMARY OF MAJOR NATURAL GAS PROJECTS IN INITIATION	DATE NEEDED	NEED DRIVER
4. Sno-King Reinforcement Projects (NPA Analysis Pilot)	Existing	Capacity, Reliability, Operational Flexibility and Aging Infrastructure
5. Gas Reliability Marine Crossing (NPA Analysis Pilot)	Existing	Reliability, Operational Flexibility and Aging Infrastructure

Figure M-27: Natural Gas Planned Projects in Initiation Phase



4. Sno-King Reinforcement Projects (NPA Analysis Pilot)

Estimated Need Date: Existing

Date Need Identified: 2009

The Sno-King area includes the south Snohomish county area and the Central/Northern King county areas and includes approximately 200,000 gas customers.

NEED ASSESSMENT. PSE begins studying an area when certain study triggers occur that affect system reliability including critical natural gas pipeline pressures and flows, load/customer growth projections, gas supply contracts, excessive cold weather actions (CWAs), and other information that surfaces. Data is gathered and assumptions are made as follows.

Planning Study Triggers

- Minimum pressure guidelines have been crossed
- Maximum flow guidelines have been reached
- Load and customer growth
- Increased CWAs
- Natural gas customer outages

Data and Assumptions

- This study analyzed the Southern Snohomish county area and the Central/Northern King county areas over a planning horizon of 10 years during multiple timeframes, and has extended this timeframe to 25+ years multiple times to ensure solutions were also optimized for the long term.
- Individual load growth of specific areas was completed in detail where needed for these studies. This includes the review of over 5,000 building permits in the Seattle area to help determine commercial gas load growth in this area in the next five years.
- The latest PSE load forecasts were coordinated with detailed planner knowledge of localized growth to determine the final yearly predicted load growth.
- The latest PSE gas models were used that contain all pipes down to the service level and the latest natural gas load files. Natural gas loads are calculated for every gas customer on our system based on their history and then this is temperature-compensated and applied to the models.
- All models are baselined against actual flows, loads and pressures to ensure accuracy.
- The loads in the model contain no interruptible loads for these studies.

NEEDS IDENTIFIED. The analysis determined that there are operational reliability concerns created by increased load growth resulting in low pressure issues, operational flexibility concerns due to limitations caused by excessive Cold Weather Actions, and aging infrastructure concerns.

Capacity. Some of the fastest growing zip codes are contained in the Sno-King area, which are contributing to significant load growth over many years. Both the supply and distribution systems need reinforcement in order to serve recently added and projected customer loads.

Reliability. The supply system is unable to meet minimum design requirements without manual operations (see “operational flexibility” below). The downstream supply and distribution systems cannot maintain adequate system pressures when the upstream supply system is unable to maintain its system pressure.

Operational Flexibility. Six Cold Weather Actions are scheduled for this area along with 100 percent curtailments, and these actions are markedly insufficient to address the reliability concerns. Manual operations carry an inherent operational risk that an action may not be able to be implemented when needed due to weather and road conditions and/or equipment and personnel issues. There are limitations to manual operations based on location and availability of sufficient equipment and trained personnel. As demand continues to increase, manual operations are insufficient to support the system.

Aging infrastructure: Critical pieces of the pipeline infrastructure have maintenance concerns in addition to a need to be increased in size for capacity reasons. Both of these issues contribute to reliability concerns.

SOLUTION ASSESSMENT. Solution criteria includes technical and non-technical criteria as follows that must be met. PSE developed solutions criteria for system performance in the areas of capacity, reliability, cost and constructability.

Technical Solution Criteria

- Must meet all performance criteria for supply and distribution system requirements, including reliability
- Must address all relevant needs identified in the Needs Assessment Report
- Must not cause any adverse impacts to the reliability or operating characteristics of PSE’s system
- Must be able to meet a 25-year planning horizon – staging (phased approach) is acceptable
- Must be safe

Non-technical Solution Criteria

- Meet environmentally impacts and permitting requirements
- Constructible to meet capacity need dates, both current and future
- Utilize proven/mature technology
- Reasonable, prudent project costs
- Must assess and account for community and transportation impacts

Evaluation of Solution Alternatives. PSE is completing a thorough alternative analysis that includes analyzing pipeline and non-pipeline solutions (including LNG, CNG, energy efficiency and demand response) to determine the most cost-effective solution for this area's need.

CURRENT STATUS. Final completion of the long-term alternatives analysis is expected to be completed by the end of 2022.

5. Natural Gas Reliability Marine Crossing (NPA Analysis Pilot)

Estimated Need Date: Current
Date Need Identified: 2019

The marine crossing in King County serves roughly 13,000 customers on the Gig Harbor peninsula and Vashon/Maury Island.

NEEDS ASSESSMENT. A high pressure natural gas supply system needs assessment was performed for the Gig Harbor peninsula, Vashon Island and Maury Island area. Based on results of this needs assessment, it has been determined a long-term supply solution should be developed, while also developing a backup supply solution for the area.

NEEDS IDENTIFIED. The dynamic marine environment in which this crossing has operated for more than 50 years has resulted in the need for reinforcement or replacement of parallel 8-inch undersea high pressure laterals. Seafloor movement and fatigue induced by ocean currents have resulted in the crossing nearing end of its service life.

Reliability. The supply system is unable to meet minimum design requirements should the lateral exceed fatigue limitations. As a result, the downstream supply and distribution systems cannot maintain adequate system pressures when the upstream supply system is unable to maintain its system pressure.

Operational Flexibility. The existing marine crossing is the only pipeline supply of natural gas to roughly 13,000 customers on the Gig Harbor peninsula and Vashon/Maury Island. While the supply is augmented by PSE's Gig Harbor LNG facility to meet system peak loads, a pipeline connection is required to maintain natural gas service to all customers in the area.

Aging infrastructure: Segments of the undersea pipeline infrastructure have maintenance concerns requiring mitigation.

SOLUTION ASSESSMENT. PSE developed solutions criteria that must be met in the areas of capacity, reliability, cost, constructability and customer impact.

Solution Criteria

- Must meet all technical criteria
- Must be able to be constructed and permitted within a reasonable timeframe
- Must have reasonable project costs
- Must use mature technology
- Must have the least customer impact

Evaluation of Solution Alternatives. PSE is completing a thorough alternative analysis that includes analyzing pipeline and non-pipeline solutions to determine the most cost effective solution for this area's need.

CURRENT STATUS. Project initiation to review alternative solutions has begun and is expected to be completed in 2021. Limited system modifications are planned in 2021 to enable operation of an emergency backup supply plan should the marine crossing experience a failure prior to completion of the project.