CLEAN ENERGY ACTION PLAN

CHAPTER TWO

PSE PUGET SOUND ENERGY

2023 Electric Progress Report

Contents

1. Introduction

Washington State's Clean Energy Action Plan (CEAP) is a new aspect of Puget Sound Energy's (PSE's) Integrated Resource Plan (IRP) process. Introduced in the Clean Energy Transformation Act (CETA) in 2019, the CEAP identifies steps utilities can take over the next 10 years to meet the requirements of CETA. This is PSE's first Electric Progress Report and the first to include a CEAP update. As with any new requirement or assessment, the CEAP will evolve, and future IRPs will benefit from the lessons we learned in previous planning processes.

Puget Sound Energy is committed to achieving the requirements of CETA and carbon neutrality by 2030 and a carbon-free electric energy supply by 2045, and the CEAP presented here reflects these goals. Bridging PSE's Clean Energy Implementation Plan (CEIP) and IRP, the CEAP informs our decisions about specific and interim targets and actions over ten years, per RCW 19.280.030[1].

Table 2.1 presents near-term renewable and non-emitting — or clean energy — targets starting in the 2021 IRP and progressing through this progress report. The 2021 IRP established a clean energy target with a linear ramp from existing renewable energy generation to the 80 percent target in 2030. The 2021 CEIP expanded this target to make aggressive progress near-term toward the 80 percent goal. This 2023 Electric Progress Report (2023 Electric Report) retains the 63 percent clean energy target for 2025 established in the 2021 CEIP; however, given an increase in the load forecast, this report's resource plan requires additional renewable and non-emitting generation to meet the same target.

Table 2.1: Renewable and Non-emitting Energy Targets for 2025

Document	Clean Energy Target[1] by 2025 (%)	Clean Energy Generation to Meet Target[1] (MWh)
2021 IRP	56	10,046,493
2021 CEIP	63	11,381,593
2023 Progress Report	63	12,324,846

Notes: Clean energy targets represent a percent or quantity (MWh) of renewable or non-emitting energy of delivered load. The delivered load is adjusted for projected future demand-side resources (conservation, demand response, select distributed energy resources), PURPA contracts, and voluntary renewable programs.

2. Requirements

The 2021 IRP marked a significant departure from past IRPs largely due to CETA. The new rules, WAC 480-100-620 (12),[2] outline the requirements for this report. The utility must develop a 10-year clean energy action plan for implementing RCW 19.405.030[1]□ .

In this CEAP, the utility must include the following:

- A 10-year action plan that is the lowest reasonable cost (see section 3)

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[1] RCW 19.280.030

[2] WAC 480-100-620

- Establish resource adequacy requirement (see section 3.2)
- Identify any need to develop new or to expand or upgrade existing bulk transmission and distribution facilities (see section 5)
- Identify cost-effective conservation potential assessment (CPA) (see section 3.1)
- Identify how the utility will meet the requirements of the clean energy transformation standards (see section 4)
- Identify potential cost-effective demand response (see section 3.4)
- Identify renewable resources, non-emitting electric generation, and distributed energy resources and how they contribute to meeting the resource adequacy requirement (see section 3.3)
- Identify the nature and extend for alternative compliance reliance (see section 6)
- Incorporate the social cost of greenhouse gasses as a cost adder (see section 7)

3. Ten-year Resource Additions

From the 2023 Electric Progress Report 22-year period, Table 2.1 summarizes the 10-year outlook for the resource mix in PSE’s preferred portfolio. The portfolio benefit analysis, which considers the equitable distribution of benefits and how burdens may be reduced over the CEAP's ten-year horizon, informed our final selection of resources while ensuring the preferred portfolio met PSE’s peak capacity, energy and renewable needs, and addressed market risk.

Table 2.2: 10-year Annual Incremental Resource Additions Preferred Portfolio

Resource	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total 2024–2033
Conservation[1]	33	32	44	36	36	60	41	42	78	43	445
Demand Response	71	65	71	47	49	16	17	17	17	16	387
DER Solar[2]	97	75	51	70	73	93	91	98	98	102	850
Net Metered Solar	*38*	*21*	*21*	*40*	*40*	*61*	*61*	*67*	*67*	*71*	*490*
CEIP Solar	*55*	*24*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*79*
New DER Solar	*4*	*30*	*30*	*30*	*33*	*32*	*30*	*31*	*31*	*31*	*281*
DER Storage[3]	21	18	29	32	29	28	30	28	4	4	223
CETA-qualifying Peaking Capacity[4]	237	0	237	0	237	0	0	0	0	0	711
Wind	300	300	500	0	0	0	400	200	100	100	1,900
Solar	100	0	0	0	200	400	0	0	0	0	698
Hybrid Total	150	150	400	0	150	600	0	0	0	0	1449
Hybrid Wind	*0*	*100*	*200*	*0*	*100*	*200*	*0*	*0*	*0*	*0*	*600*

Resource	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total 2024–2033
Hybrid Solar	*100*	*0*	*100*	*0*	*0*	*200*	*0*	*0*	*0*	*0*	*399*
Hybrid Storage	*50*	*50*	*100*	*0*	*50*	*200*	*0*	*0*	*0*	*0*	*450*
Standalone Storage	0	100	600	300	0	0	0	0	100	100	1,200
Total	1010	740	1932	485	774	1198	579	385	396	364	7,862

Notes:

1. Conservation in winter peak capacity includes energy efficiency, codes and standards, and distribution efficiency.
2. Distributed Energy Resources (DER) solar includes customer solar photovoltaic (PV), Clean Energy Implementation Plan (CEIP) solar additions, non-wires alternatives, and ground and rooftop solar additions.
3. Distributed Energy Resources (DER) storage includes CEIP storage additions, non-wires alternatives, and distributed storage additions.
4. CETA-qualifying peaking capacity is functionally similar to natural gas peaking capacity but operates using non-emitting hydrogen or biodiesel fuel. We describe CETA qualifying peaking capacity in Chapter Five: Key Analytical Assumptions and present alternative fuel assumptions in Appendix D: Generic Resource Alternatives.

3.1. Conservation Potential Assessment

We analyzed demand-side resource (DSR) alternatives in a conservation potential assessment (CPA) to develop a supply curve used as an input to the portfolio analysis. Then the portfolio analysis determines the maximum amount of energy savings the model captured without raising the overall electric portfolio cost. This study identified the cost-effective level of conservation, which includes non-energy benefits from the portfolio benefit analysis to include in the portfolio. We evaluated the amount of cost-effective conservation to meet the portfolio's capacity and energy needs, optimizing the lowest cost and considering distributed and centralized resources.

➔ See Appendix E: CPA and Demand Response Assessment for the full CPA Assessment. A complete discussion of how we chose the conservation levels for the preferred portfolio is in Chapter Three: Resource Plan.

Figure 2.3: 10-year Achievable Technical Potential Conservation Savings (Energy aMW and Peak MW)

Demand-side Resources	Total Savings (aMW)	Winter Peak Savings (MW)	Summer Peak Savings (MW)
Energy Efficiency	167	214	212
Distribution Efficiency	11	11	10
Codes and Standards	159	196	245

3.1.1. Impacts and Actions

This electric report informs the target setting process and, through this analysis, we identified 10-year savings of 167 aMW as cost-effective. We will use this to inform the draft 2023 Energy Independence Act (EIA) target for the 2024-

2025 biennium after adjusting for intra-year ramping and savings at the meter. Under the EIA, utilities must pursue all cost-effective, reliable, and feasible conservation. Puget Sound Energy fulfills these requirements by undertaking additional analysis to identify the conservation potential over 10 years and set two-year targets. Setting the final two-year targets is part of PSE's biennial conservation plan process, which will take place over the next few months and builds on the information in this electric progress report.

3.2. Resource Adequacy

We must meet capacity need over the planning horizon with firm capacity resources or contractual arrangements to maintain reliability. All resources, including renewable resources, distributed energy resources, and demand response, contribute to meeting the capacity needs of PSE's customers, but they make different kinds of contributions.

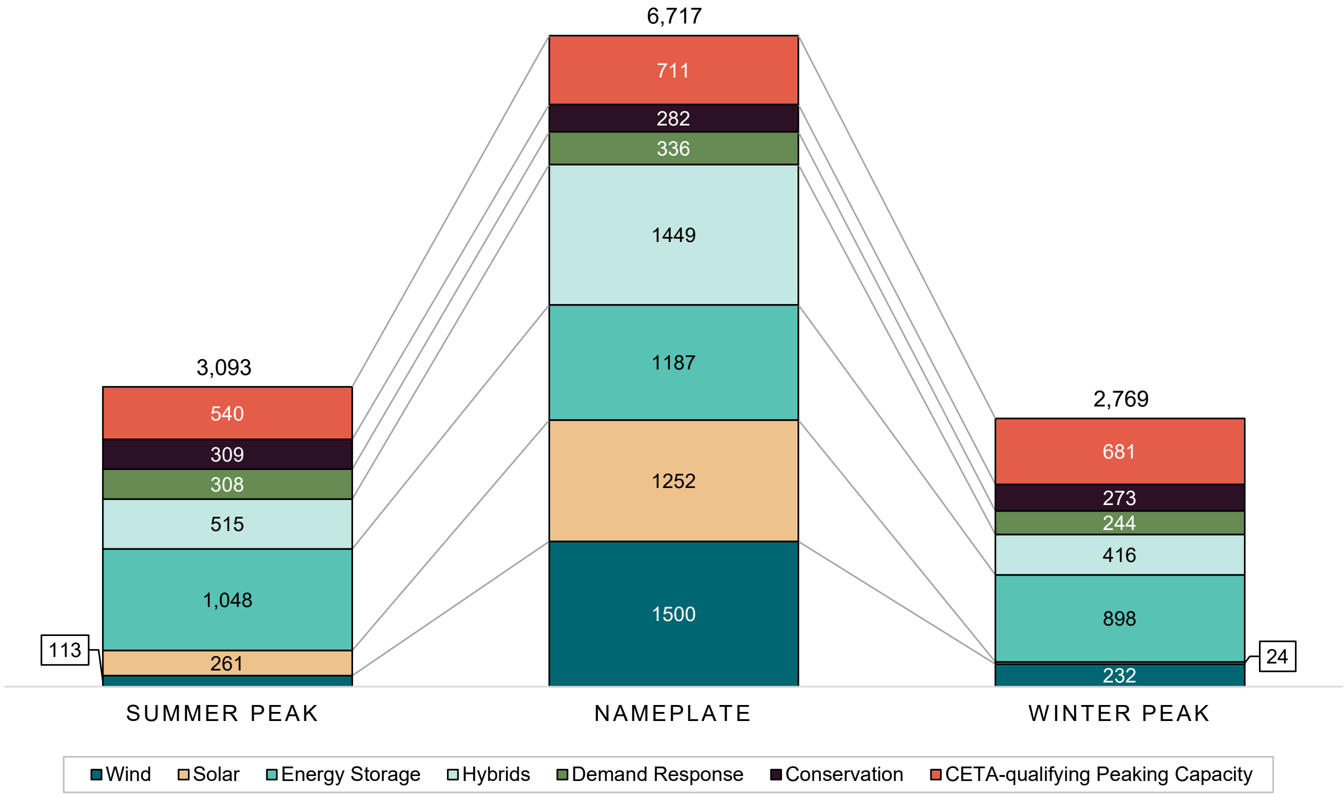
We have established a five percent loss of load probability (LOLP) resource adequacy metric to assess physical resource adequacy risk. The LOLP analysis measures the likelihood of a load curtailment event in any given simulation regardless of the frequency, duration, and magnitude of the curtailment(s). Therefore, the possibility of capacity being lower than the load anytime in the year cannot exceed five percent.

Assessing the peak capacity each resource can reliably provide is an integral part of resource adequacy analysis. To quantify the peak capacity contribution of renewable resources (wind, hydro, and solar) and other resources (thermal, storage, demand response, and contract), we calculate the effective load-carrying capacity (ELCC) for each of those resources. The ELCC of a resource is unique to each utility and dependent on load shapes and supply availability, so it is hard to compare the ELCC of PSE's resources with those of other entities.

We analyzed summer and winter peak capacity for this report, and the analysis indicated that the winter peak is higher than the summer peak. With the increase of renewable energy and energy storage in the portfolio, those resources contribute to the summer peak need better than the winter. For example, solar has a four percent peak capacity contribution in the winter but a 55 percent contribution in the summer. We added solar to the portfolio because it meets the CETA requirement and the summer peak need, but it does very little to meet the winter peak need.

Because the peak capacity contribution of each resource does not match the nameplate energy values, we need more resources to meet the peak need. For example, solar's 24 MW winter peak capacity contribution requires over 1,200 MW of installed nameplate capacity. After adjusting for peak capacity contribution, 6,717 MW of new resources installed nameplate capacity equals 3,093 MW summer peak capacity and 2,769 MW winter peak capacity, as detailed in Figure 2.1.

Figure 2.1: Nameplate Capacity Adjusted to Peak Capacity Contributions (MW) for 2030



➔ See Chapter Seven: Resource Adequacy Analysis and Appendix L: Resource Adequacy for a complete description of the resource adequacy modeling.

3.3. Renewable and Non-emitting Resources

We modeled several types of renewable and non-emitting utility-scale resources for this Electric Progress Report. Supply-side resources provide electricity to meet the load. These resources originate on the utility side of the meter. These resources include wind, solar, pumped hydro energy storage, battery energy storage, hybrid resources (combination of wind, solar, and battery), combustion turbines using alternative fuels such as biodiesel and hydrogen, and advanced nuclear small modular reactors (SMR).

Distributed energy resources (DER) are small, modular energy generation and storage technologies installed on the distribution systems rather than the transmission system. Distributed Energy Resources are typically under 10 MW and provide a range of services to the power grid. These resources include wind, solar, storage, and demand response technologies and may be networked to virtual power plants (VPPs). This report included demand response, distributed solar, and distributed storage programs as generic DERs.

➔ A full description of resources modeled for this progress report is in Appendix D: Generic Resource Alternatives, with a brief description in Chapter Five: Key Analytical Assumptions.

3.3.1. Impacts and Actions

Biodiesel

Biodiesel is a commercially available fuel that can be combusted in existing and new peaking plants. Biodiesel provides a carbon-neutral alternative to existing backup fuels like petroleum-derived diesel. Biodiesel is energy-dense and can be stored on site for short periods — one to two months — to provide reliability in the event green hydrogen or renewable natural gas supplies are exhausted or unavailable.

We will continue to monitor and engage with regional biodiesel manufacturers to determine the limits of biodiesel fuel supply. We anticipate a shift in biodiesel supply as the transportation sector is rapidly electrified and alternative fuels, such as biodiesel, become increasingly available to other industries.

Renewable Diesel

Renewable diesel — frequently referred to as R99 — is a commercially available fuel that can be combusted in various existing and new peaking plants. R99 provides a carbon-neutral alternative to existing backup fuels like petroleum-derived diesel. R99 is energy dense and can be stored on site (for periods measured in years) to provide reliability if green hydrogen or renewable natural gas supplies are exhausted or unavailable. Puget Sound Energy successfully tested R99 fuel in the Crystal Mountain generator and is coordinating with authorities to test R99 in a Frederickson generator in 2023.

We will continue to monitor and engage with regional R99 manufacturers to determine the limits of the R99 fuel supply. We anticipate an increase in R99 supply in 2024 as the transportation sector is rapidly electrified and alternative fuels, such as R99, become increasingly available to other industries.

Biodiesel and renewable diesel are derived from non-petroleum feedstocks like vegetable oil, animal fats, municipal waste, agricultural biomass, and woody biomass. Biodiesel is produced using a transesterification separation method, and renewable diesel uses a hydrogenation process. Renewable diesel meets all of the ASTM–D975 specifications. Renewable diesel can be blended with or replace petroleum-derived diesel without affecting engine operations or air operating permit requirements. Renewable diesel has a carbon intensity of approximately 60 percent less than petroleum diesel and reduced NOx, particulate matter, and VOC emissions.

Hydrogen

Green hydrogen has the potential to aid in the decarbonization of the electric sector without compromising reliability standards. Electrolyzers convert surplus renewable energy to hydrogen gas stored for long periods until needed during a peak event. During a peak event, green hydrogen is combusted with either existing retrofitted equipment or at new peaking plants. Until recently, high costs have dissuaded the development of hydrogen infrastructure for the energy sector, but production tax credits included in the Inflation Reduction Act have the potential to put green hydrogen in cost-parity with more conventional fuels.

Puget Sound Energy aims to be a leader in developing hydrogen infrastructure to bring the benefits of green hydrogen to the Pacific Northwest. Puget Sound Energy holds a place on the board of the Pacific Northwest Hydrogen Association[3], which is seeking to establish a network of suppliers, storage, and off-takers in the region as part of the Department of Energy's Hydrogen Hub (H2Hub) Funding Opportunity as part of the Infrastructure Investment and Jobs Act (IIJA). In addition to our work with Pacific Northwest Hydrogen Association, we are also working with Fortescue Future Industries and other regional interested parties to explore the development of a hydrogen production facility at the former Centralia coal mine in Centralia, Washington[4].

Beyond these initial efforts, we may explore pilot programs soon to learn more about blending hydrogen in existing, retrofitted, and new peaking plants. We will also continue to research fuel supply and security considerations.

Advanced Nuclear and Other Emerging Technologies

Clean energy dispatched on demand will be a key element of a decarbonized power grid. Energy storage, such as batteries, improves the ability of wind and solar resources to follow demand, but the energy-limited nature of energy storage systems constrains their effectiveness in longer-duration peak events. We are currently missing cost-effective clean energy resources, which follow load and generate power through long-duration peak events. Several emerging resources have the potential to fill this niche but require advancements in operability and commercial availability. We will continue to monitor the development of technologies such as advanced nuclear small module reactors (SMR), carbon capture and sequestration, and deep-well geothermal.

Energy Storage

Energy storage will be an essential component of a decarbonized power system to shift variable energy resources and load. As energy storage is added to PSE's system, we will learn how to use this new resource to optimize operational efficiency. We are reviewing energy storage submittals as part of the ongoing 2021 All-Source Request for Proposal (RFP).

We will also monitor advances in energy storage technology, such as new battery chemistries and long-duration batteries, or other storage mediums, such as gravity- or compression-based storage systems. We will evaluate these technologies as they become commercially viable.

3.4. Demand Response

Demand response programs are voluntary, and once enrolled, customers usually receive notifications in advance of forecasted peak usage times, requesting them to reduce their energy use. Some programs require action by the customer; others can be largely automated and are usually referred to as direct load control programs. For example, an

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[3] https://pnwh2.com/

[4] https://ffi.com.au/news/centralia/

automated program might warm a customer's home or property earlier than usual with no action required on the part of the customer.

One example of a program that requires customer action is asking a wastewater plant to curtail pumping during certain peak energy need hours if they can. Because customers can always opt out of an event, demand response programs include some risk. If PSE relies on a certain amount of load reduction from demand response to handle a peak event, but customers opt out, we must use generating resources to fill the customer's needs.

We organized demand response programs modeled for this 2023 Electric Report in four categories:

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

➔ See Appendix E: Conservation Potential and Demand Response Assessments for the full CPA Assessment. We included a complete discussion of how we chose the demand response programs for the preferred portfolio in Chapter Three: Resource Plan Decisions.

Figure 2.4 lists the estimated 10-year achievable technical potential for demand response programs modeled for this report's residential, commercial, and industrial sectors. The table shows the attainable potential of each demand response program in MW, and the winter and summer peak need it fills to illustrate the total potential impact of demand response on system peak.

Table 2.4: 10-year Achievable Technical Potential Demand Response Programs for Model Year 2033 (MW)

Program	Category	Nameplate	Winter Peak	Summer Peak
Signal-capable Standard Water Heater[1]	Residential	74	61	51
Signal-capable Electric Heat Pump Water[1]	Residential	16	14	9
Signal-capable Heating, Ventilation, and Air Conditioning[1]	Residential, Commercial	102	73	98
Bring Your Own Smart (Internet-connected) Thermostat	Residential, Commercial	83	65	64
Signal-capable Electric Vehicle Charger[1]	Residential	21	15	20
Reduced (Lower) Electric Usage at Utility's Request	Commercial, Industrial	20	14	21
Time of Day Rates (Optional)	Residential, Commercial, Industrial	58	33	77
Electric Rate Allowing Electricity Cut Off in Periods of High Demand	Commercial	12	9	11

Note:

1. Capable of receiving internet, cellular, or radio signals.

3.4.1. Impacts and Actions

Distributed energy resources, including demand response, are a significant component of PSE's preferred portfolio from the 2023 Electric Progress Report and represent a piece of our strategy to achieve the targets laid out under CETA. Puget Sound Energy issued a DER Request for Proposal (RFP) in 2022. We are still working through the analysis and will have an updated target in the 2023 CEIP Biennial update.

4. Equitable Transition to Clean Energy

The Clean Energy Transformation Act (CETA) sets out important new expectations for the clean energy transition: that utilities must ensure that all customers benefit from the transition to clean energy.

4.1. Assess Current Conditions

To move toward an equitable transition to clean energy, we performed an economic, health, and environmental benefits (EHEB) assessment (the assessment) in 2021 to guide us as we developed our CEAP and CEIP. The purpose of the assessment was two-fold: first, to use the definitions we provided in our CEIP for named communities to identify highly impacted communities and vulnerable populations within our service area, and second, to measure disparate impacts to these communities using specific customer benefit indicators.

➔ See the updated assessment in Appendix J: Economic, Health, and Environmental Assessment of Current Conditions.

The initial qualitative and quantitative customer benefit indicators we developed through the assessment provide a snapshot of the economic, health, environmental, and energy security and resiliency impacts of resource planning on highly impacted communities and vulnerable populations within PSE's service territory. PSE built upon those initial customer benefit indicators in the assessment in developing its CEIP. Due to the timing of the IRP process and the CEIP adjudication, the proposed customer benefit indicators included in the CEIP may change based on the upcoming Washington Utilities and Transportation Commission decision on PSE's CEIP and in the future through public participation and input from PSE's Equity Advisory Group. The customer benefit indicators help measure progress toward achieving an equitable distribution of benefits and reducing burdens.

4.2. Customer Benefit Indicators

A key component to ensuring the equitable distribution of burdens and benefits and a reduction of burdens to vulnerable populations and highly impacted communities in the transition to a clean energy future is to include customer benefit indicators (CBIs) in the preferred portfolio development process. For this 2023 Electric Progress

Report, PSE used the CBIs established in the 2021 CEIP through extensive public participation and consultation with our equity advisory group.

We expanded on applying CBIs to the portfolio analysis with input from interested parties. First, we linked CBIs to specific portfolio modeling outputs to reflect customer benefit indicators in developing the preferred portfolio. We then combined these outputs into broader CBI areas, providing a context for interpreting the portfolio outputs. We indexed each portfolio from the sensitivity analyses on how well it performed in each CBI area to understand which benefits or burdens it may confer on our customers. Portfolios had to score well in several CBI areas to be considered in a preferred portfolio.

➔ See Chapter Three: Resource Plan, Chapter Eight: Electric Analysis, and Appendix H: Electric Analysis and Portfolio Model for more detail on the customer benefit indicator framework.

In summary, we have taken several actions that put us on a pathway to ensure all customers benefit from the transition to clean energy:

- Developed a public participation plan for the CEIP to obtain input on the equitable distribution of benefit and burdens
- Established the Equity Advisory Group
- Refined customer benefit indicators and metrics with the EAG and the CEIP public participation process
- Updated the portfolio benefits analysis to incorporate the customer benefit indicators and related metrics in the 2023 Electric Progress Report and future IRPs or CEIPs

Identifying and using customer benefit indicators is a developing process. Future IRPs will benefit from more input from the Equity Advisory Group (EAG) and the CEIP public participation process.

4.3. Vulnerable Populations and Highly Impacted Communities

As part of our work for the CEAP, we reviewed the CBI baseline data, often broken down into metrics for vulnerable populations and highly impacted communities, published in the 2021 CEIP. This report provides more detailed information about the 2020 and 2021 CBI data.

We will publish the metrics for 2022 for all CBI data included in Appendix J: Economic, Health and Environmental Assessment of Current Conditions of this report in our 2023 biennial CEIP update. We incorporate vulnerable populations and highly impacted communities in the IRP process by considering these groups while developing the achievable technical potentials for energy efficiency programs as part of the CPA discussed in Appendix E: Conservation Potential and Demand Response Assessments. The generic supply side resources we studied as part of the IRP lack detailed enough geographic information to establish relationships between resource selection and impacts on named communities.

➔ See Appendix J: Economic, Health, and Environmental Assessment of Current Conditions for details on the changes to the analyses.

5. Resource Deliverability

We will work to optimize our use of PSE's existing regional transmission portfolio to meet our growing need for renewable resources in the near term. However, the Pacific Northwest transmission system may need significant expansion, optimization, and possible upgrades in the long term 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. Table 2.5 shows the regional transmission need for new resources outside PSE.

Table 2.5 Regional Transmission Need Based on 2023 Preferred Portfolio (MW)

Region	2030 (MW)	2033 (MW)
East of the Cascades (Central and Eastern Washington)	3,449	3,447
Rocky Mountain Region (Montana and Wyoming)	400	800
Cross Cascades Total	3,849	4,247
British Columbia	0	0

➔ See Appendix J: Regional Transmission Resources from the 2021 IRP on specific opportunities for expanding transmission capabilities and regional efforts to coordinate transmission planning and investment. The 10-year delivery system plan is in this report's Appendix K: Delivery System Planning.

Our delivery system needs investments to deliver energy to our customers from the edge of PSE's territory and to support DERs within the delivery grid. The delivery system 10-year plan described in Appendix K: Delivery System Planning identifies work needed to ensure safe, reliable, resilient, smart, and flexible energy delivery to customers, regardless of resource fuel source. This work includes specific upgrades to the transmission system to meet NERC compliance requirements, other evolving regulations related to DER integration and markets, and distribution system upgrades to enable higher DER penetration. Specific delivery system investments will become known when energy resources, whether centralized or DERs, begin siting through the established interconnection processes. The readiness of the grid and customers for DER integration will decrease the cost of interconnection and increase the number of viable locations. Proactive investments in grid modernization are also critical to support the clean energy transition and maximize benefits. We summarized the key investment areas in the following section.

5.1. Impacts and Actions

Puget Sound Energy is pursuing the acquisition of new additional transmission capacity and optimization of existing transmission capacity rights required to facilitate the delivery of its preferred resource portfolio. We are exploring ongoing opportunities to contract with the Bonneville Power Administration (BPA) for additional transmission rights by submitting transmission service requests (TSRs) and participating in BPA's annual cluster study. The BPA annual cluster study results may trigger requirements for funding BPA system reinforcement projects needed to award the requested TSR(s). Funding these reinforcement projects will be critical to adding capacity to the regional transmission system and projects delivering to PSE's system.

Puget Sound Energy seeks to repurpose specific portions of our transmission portfolio to enhance our value to align with the preferred resource portfolio. Existing Mid-C transmission capacity allocated for market purchases could be strategically redirected for new renewable projects and projects delivering to Mid-C. Colstrip Units 3 & 4 transmission rights could be repurposed for new Montana resource deliveries. In addition, standalone PSE generation facilities could be further developed to co-locate with new renewable projects for optimized energy delivery over shared transmission (e.g., Lower Snake River, Wild Horse, Goldendale).

6. Achieving CETA Compliance: 100 Percent Greenhouse Gas Neutral by 2030

Under CETA, utilities can meet up to 20 percent of the 2030 greenhouse gas neutral standard with an alternative compliance option. Utilities can use these alternative compliance options from January 1, 2030, to December 31, 2044. An alternative compliance option includes any combination of the following:

- Investing in energy transformation projects that meet criteria and quality standards developed by the Department of Ecology, in consultation with the Department of Commerce and the Commission
- Making an alternative compliance payment in an amount equal to the administrative penalty
- Purchasing unbundled renewable energy credits (RECs)

For this report, we modeled unbundled RECs to achieve CETA compliance 2030–2044, where renewable and non-emitting energy could be less than 100 percent of delivered energy annually. The preferred portfolio only incurs one alternative compliance payment in 2030 of $3.18 million worth of unbundled RECs to make up for 3.4 percent of delivered energy. For all future years of the CEAP horizon, the preferred portfolio meets the 100 percent standard without the need for alternative compliance options.

➔ See Chapter Five: Key Analytical Assumptions for a discussion on alternative compliance assumptions and costs. Appendix I: Electric Analysis Inputs and Results for portfolio modeling results.

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7. Social Cost of Greenhouse Gases

The social cost of greenhouse gases (SCGHG) was included per WAC 480-100-620(12)(i).[2]

➔ General assumptions for the SCGHG are in Chapter Five: Key Analytical Assumptions, and a detailed modeling description of the SCGHG is in Appendix G: Electric Price Models.
