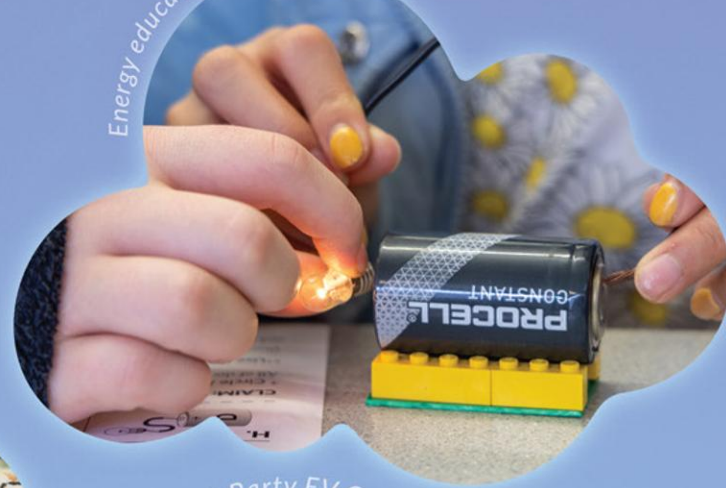
SNOHOMISH COUNTY
PUD
PUBLIC UTILITY DISTRICT NO. 1


Energy education in local classrooms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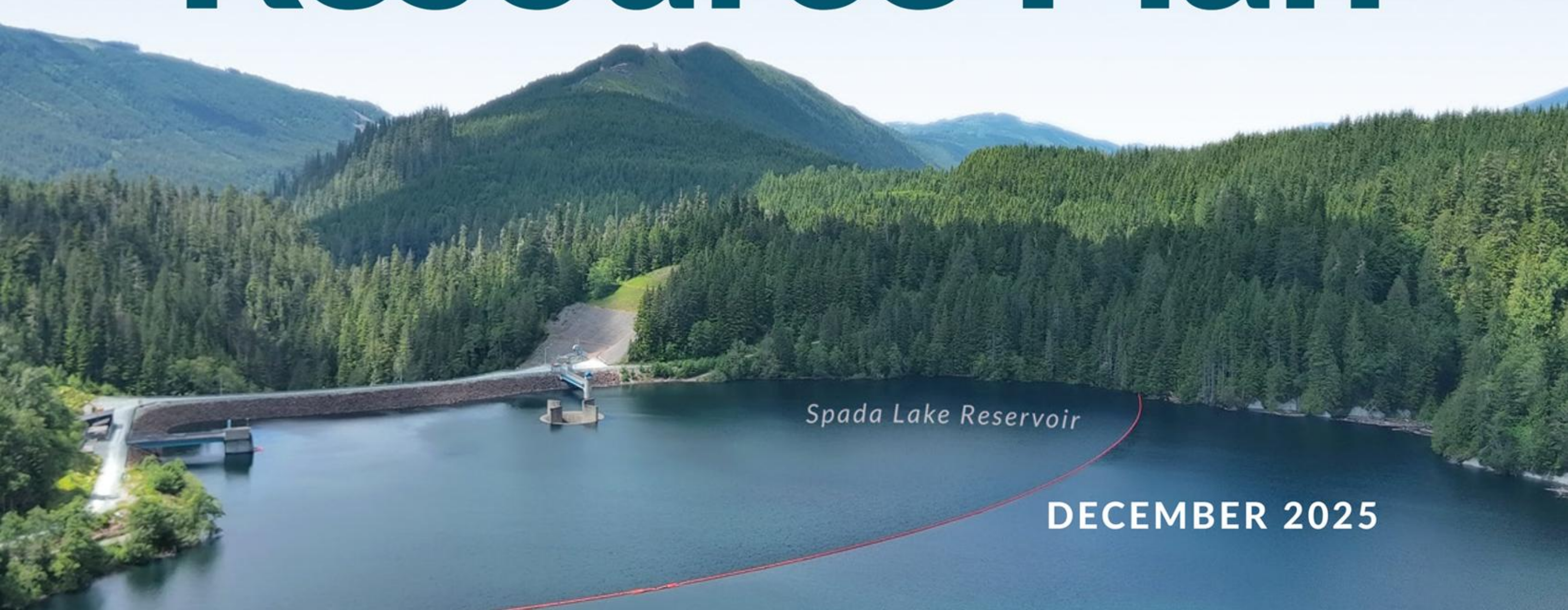
Block Party EV Car Show

2025 Integrated Resource Plan


Spada Lake Reservoir

DECEMBER 2025

To Our Customers, Stakeholders, and Community Partners,

I am pleased to present Snohomish County PUD's 2025 Integrated Resource Plan (IRP), a strategic roadmap that guides how we will meet the energy needs of our customers in the years ahead. This plan reflects our commitment to delivering reliable, affordable, and environmentally responsible power while remaining responsive to a rapidly evolving energy landscape.

The 2025 IRP is shaped by modest projected load growth and a dynamic regulatory environment, including Washington State's Renewable Portfolio Standard and the Clean Energy Transformation Act. In response, our resource strategy emphasizes a balanced portfolio of conservation, demand response, clean energy resources, and strategic purchases of Bonneville Power Administration (BPA) Tier 2 power. These additions will help us meet growing demand while maintaining flexibility and resilience.

Importantly, this plan positions the PUD to adapt to upcoming changes in our power supply, including BPA's new Load-Following product and the next BPA power contract beginning in 2028. By planning ahead, we ensure that our resource choices remain aligned with our long-standing values: low rates, clean power, and reliable service.

At Snohomish PUD, our purpose is to deliver essential utility services to help our communities thrive. The 2025 IRP reflects that purpose by prioritizing sustainability, affordability, and reliability. We are proud of the work that has gone into this plan and look forward to continuing our tradition of leadership in clean energy and customer service.

Thank you for your continued trust and partnership.

Sincerely,

Jason Zyskowski

Jason Zyskowski
Chief Energy Resource Officer
Snohomish County PUD

Acknowledgements

The 2025 Integrated Resource Plan represents the contributions of numerous individuals both within the PUD and external. We acknowledge the thoughtful input from all stakeholders whose engagement and expertise informed the development of this plan. In particular we want to recognize the contributions from:

Our Customers.

PUD staff engage our customers for questions, comments and feedback on our planning processes and to gain their perspectives. This feedback is invaluable as we seek to shape a resource strategy that meets our customers' needs. There have been many public engagements throughout the development and finalization of the 2025 IRP, which are described in more detail in Technical Appendix C. PUD staff thank our customers for their participation, we are grateful for the opportunity to serve as public servants, to provide safe, reliable, affordable and environmentally sustainable electricity to our community.

Our Elected PUD Commissioners.

During the development of the 2025 IRP, Commissioners Sidney Logan (President, District 1), Tanya Olson (Vice-President, District 3), and Julieta Altamirano-Crosby (Secretary, District 2) provided regular feedback through their active participation in public meetings, which has helped shaped the 2025 IRP to reflect their perspectives on behalf of their constituents.

Our IRP Technical Team.

The PUD utilizes a cross-functional team of subject matter experts to peer review IRP inputs and outputs to ensure the technical soundness of the approach, as well as the appropriateness of the resulting strategy. Members of the Technical Team for the 2025 IRP include: Aaron Swaney, Adam Cornelius, Adam Lewis, Adam Peretti, Alex Chorey, Andrew Cox, Andrew McDonnell, Angela Johnston, Brenda White, Christina Leinneweber, Dawn Presler, Doris Payne, Doug O'Donnell, Dwane Small, Emily Kubiak, Emily Parry, Felicienne Ng, Greyson Murakami, Ian Hunter, Jane Avatare, Jeanne Harshbarger, Jeff Feinberg, Jenna Peth, Jessica Spahr, John Norberg, John Petosa, Karl Haack, Kenn Backholm, Kim Johnston, Kimberly Haugen, Laura Lemke, Laura Reinitz, Lauren Way, Logan Forbis, Maria-Isabel Gomez, Marie Morrison, Michael Coe, Michael Landau, Nathan Rhoades, Nick Peretti, Orion Eaton, Peter Dauenhauer, Quinton Harrington, Rhyan Kyle, Ryan Collins, Sarah Bond, Scott Gibson, Scott Richards, Scott Spahr, Shane Frye, Shelley Pattison, Sirena Fothergill, Suzanne Oversvee, Ted Light, Zack Scott.

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1 Executive Summary

Integrated resource planning is a comprehensive process that considers how a utility will provide reliable electric service to its customers at the lowest reasonable cost while adhering to the policy requirements that govern electric utilities. This process must also consider the risks and uncertainties inherent in a rapidly changing and complex industry. Accordingly, an integrated resource plan (IRP) must be flexible, allowing the utility to adapt to changing circumstances without adverse financial or operational impacts. To achieve this objective, a range of alternatives are considered and evaluated, from which a preferred plan is established. [1]

Key steps in the PUD's 2025 IRP process

- Gather public perspectives and feedback to inform study scenarios.
- Assess the planning environment and establish guiding principles.
- Identify a variety of futures or scenarios the utility could face.
- Analyze the utility's existing and committed resources to determine the potential range of future energy and regulatory needs.
- Define the types of demand and supply-side resources considered to be reliable and commercially available over the study period to meet the future needs identified in scenarios.
- Optimize portfolios for each scenario that identify the mix of reliable and available resources best suited for meeting future energy and regulatory needs, based on lowest reasonable cost and lowest reasonable risk criterion.
- Find commonalities and themes across scenarios, selecting a portfolio or Long-Term Resource Strategy that best positions the utility to meet future needs while addressing potential risks and maintain flexibility.
- Establish a near-term action plan with steps the utility can take to implement the plan over the next two to four years.

The PUD's 2025 IRP covers the 20-year planning horizon of 2026 through 2045. This planning horizon enables the IRP to study how the PUD will transition to the 100% clean energy environment by 2045, as prescribed by Washington State's Clean Energy Transformation Act.

[1] Revised Code of Washington, Chapters 19.280 and 19.285 prescribe the statutory requirements of an integrated resource plan

Guiding Principles for 2025 IRP

The 2025 IRP effort was governed by the following guiding principles:

1. Reflect updated PUD portfolio needs and opportunities associated with the transition to the BPA Load-Following power product and the Post-2028 BPA Power Contract;
2. For future load growth not met by the PUD's existing or committed resources, implement new conservation acquisitions measures and pursue clean, renewable resource technologies where feasible. Resource planning must take into consideration resource options "that provide the optimum balance of environmental and economic elements;"
3. Comply with all applicable Board policies, regulations, state laws and established IRP planning standards; and
4. Preserve the PUD's flexibility to adapt to changing conditions.

Progress on 2023 IRP Action Plan

The PUD completes an IRP biennially, and this continuous process enables the PUD to refine its Long-Term Resource Strategy in response to the changing operating environment and make progress on objectives identified in the IRP. Below are the Action Plan items from the 2023 IRP Update, accompanied by a summary of progress achieved to date.

1. **Actively engage with BPA's post-2028 contract process and analyze new power products**
   - PUD staff engaged in the Post-2028 process and was successful in negotiating a new contract that is largely similar to the prior contract but with additional provisions for energy storage resources. Furthermore, PUD staff conducted an extensive analysis of the current BPA product offerings and determined a change to Load-Following would benefit our customers by reducing cost and cost variance in the face of extreme weather events. In October 2025 the PUD changed from BPA's Slice/Block power product to Load-Following and the 2025 IRP process was overhauled to reflect the new environment.

2. **Acquire 10.54 aMW or more cost-effective conservation by 2025**
    - As of October 13, 2025, the PUD is on track to acquire at least the target and potentially more. The results will be reported to Washington State in 2026 for the 2023 – 2025 biennium.
3. **Continue planned development of additional Time of Day Rate options for customers and explore additional cost-effective demand response programs**
    - The planned deployment of Automated Metering Infrastructure (AMI) has faced challenges and delays largely attributed to supply chain shortages. The deployment of AMI is a required prerequisite for Time-of-Day Rates. As a result, there have been delays in smart rate deployments. Despite these delays, PUD staff are continuing to develop new rate options and marketing strategies that will be launched when AMI deployment is sufficient to support program success.
4. **Develop low-cost, locally sited energy storage, and perform due diligence for future projects**
    - PUD staff are currently in the construction phase of the Arlington Battery Energy Storage System, a 25MW/100MWh battery system located at the PUD's North County facility. The PUD contracted with a developer and is providing the interconnecting substation while the developer will build and maintain the energy storage system. Anticipated commissioning of the project is expected in 2026.
    - PUD staff performed an analysis of PUD owned parcels to determine the feasibility for new energy storage sites at existing infrastructure. Staff identified three (3) potential sites with sufficient area for a new energy storage project and examined potential transmission and distribution benefits for each site.
5. **Perform due diligence on regional renewable energy projects, and prepare for potential procurement activity**
    - PUD staff published a request for proposals (RFP) for regional renewable energy projects. Staff reviewed the submitted proposals and selected a solar photovoltaic project in Eastern Washington for further consideration. The PUD released a letter of intent (LOI) and was allocated an 84.5MW share of the 127.5MW project. The solar facility is expected to reach commercial operation in 2030. Power Purchase Agreement negotiations are currently underway; if mutually acceptable terms are reached, a PPA will be presented to the Board for consideration.
6. **Acquire 50MW of short-term market contracts**
    - The PUD acquired 50MW of short-term market contracts to augment the energy and capacity position for the winter on-peak energy period from 2024-2025. These contracts provided resource-specific hydropower output from Washington facilities and included the associated incremental hydropower RECs needed for compliance with the Energy Independence Act (EIA) Renewable Portfolio Standard (RPS) compliance.

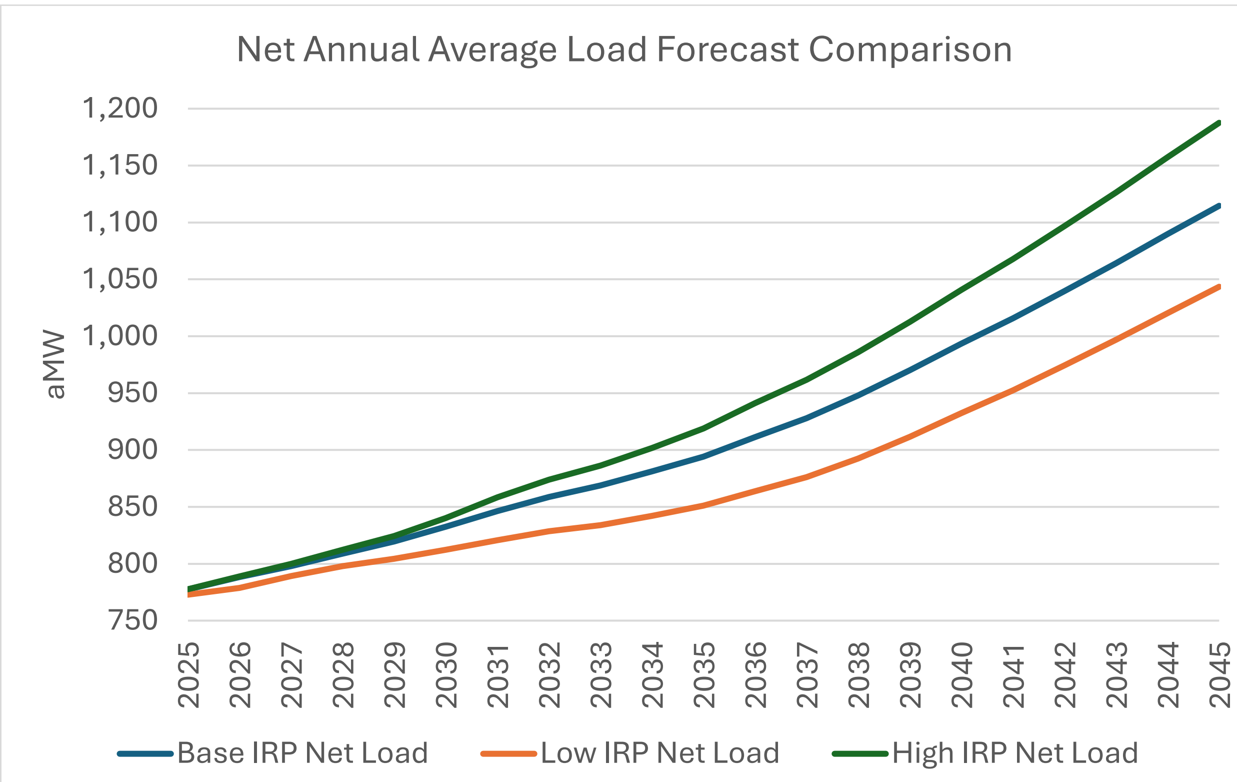
7. **Ensure continued compliance with state clean energy mandates**
    - The PUD continues to comply with the EIA, while pursuing the most cost-effective compliance pathway for PUD customers. In 2022, the PUD successfully applied the no load growth methodology for the 2021 compliance year, resulting in 2021 savings of approximately $5 million while extending the PUD's supply of EIA compliant Renewable Energy Credits (RECs) available for future compliance years. The PUD continues to transact in the REC market to supplement the PUD's supply of RECs generated from owned or contracted resources.
8. **Continue commitment to best-practice rooftop solar customer processes, while continuing evaluation of Community Solar project opportunities**
    - In response to customer feedback and Northwest Power and Conservation Council (NWPCC) work, the PUD contracted for a Solar Potential Assessment (SPA) for the first time the results of the assessment are included in this 2025 IRP. The PUD is exploring programs to maximize the benefits of customer-owned solar facilities by collaborating with new customers to provide a rate credit if RECs are granted to the PUD.
9. **Perform due diligence on local hydro capacity uprate projects**
    - After the PUD changed to the Load-Following product the need for capacity resources changed, as their attributes were now applied to the Load-Following billing paradigm. Under Load-Following, resources outside the service territory do not contribute to peak demand reduction and therefore do not have the same capacity value. The two projects envisioned for a capacity uprate are outside the PUD service territory and cannot reduce the monthly peak requirement. As a result, due diligence has been paused until the operating environment prompts reconsideration.
10. **Develop and enhance local partnerships for fusion energy**
    - PUD staff continue to engage with local fusion partners and track the development of the fusion sector. Continued engagement into the future while the technology develops is an opportunity to partner where appropriate with an emergent local sector.
11. **Continue participation in regional forums on climate change modeling, resource adequacy development, and organized market formation.**
    - The PUD continues to play a leadership role in many emerging regional issues. PUD staff have served on the leadership board and Program Review Committee of the Western Resource Adequacy Program (WRAP), served in leadership positions in work groups and task forces associated with Markets+ and the day-ahead market development effort, and contribute to committees focused on regional power planning best practices, such as the System Planning Committee, organized by the Pacific Northwest Utility Coordinating Council.

PUD Portfolio Needs

The PUD's portfolio needs are generally classified into two categories: (1) energy needs and (2) regulatory needs. Energy needs are measured as the capability to generate electricity to serve load or reduce peak demand needs, whereas regulatory needs are measured as the number of environmental attributes required to meet applicable clean energy regulatory requirements. Based on the forecasted needs of the PUD, the 2025 IRP evaluates potential portfolios that can meet both categories of needs, the results of which are summarized below.

Annual Energy Needs Grow with Load

Figure 1-1 PUD Load Forecast



Load growth in the PUD's service territory is the result of many factors including population growth, electrification, and increased adoption of electric vehicles. These factors contribute to annual energy needs and regulatory compliance needs increasing over time. This growth drives planned renewable resource procurements in the 2030's through the end of the study period. The supply of RECs in the secondary market is not viewed as sufficient to meet future

PUD needs in any scenario studied. Therefore, there is a need for resource procurements in 2030 through the end of the study period.

Key Findings of the 2025 IRP

- Throughout the entire study period and under all scenarios and sensitivities, conservation and clean energy resources represent the primary resource additions that produce the lowest cost portfolio given the PUD's increasing load and regulatory compliance requirements.
- Demand response and smart rate options are identified as a low-cost approach to mitigating demand costs of the BPA Load-Following product.
- The BPA Load-Following product supplies all capacity (ability to ramp up and ramp down with load changes) and all energy needs until 2028. After 2028, conservation, clean energy resources, and flexible purchases of BPA Tier 2 power are expected to meet energy needs.
- Local investments and customer collaboration are an important component of the lowest-cost PUD resource strategy. Conservation, demand response and local solar investments are opportunities to invest in Snohomish County and Camano Island. This opportunity is in alignment with PUD Strategic Priority #3: Actively Help Our Communities Thrive.
- Additional key insights are discussed in **SECTION 7 KEY INSIGHTS** this document.

Scenarios

The 2025 IRP utilized eight scenarios to consider the range of possible futures the PUD could face during the 2026 - 2045 study period. These scenarios were developed based on feedback from the public and PUD subject matter experts. Table 1-1 below summarizes key variables considered by the scenarios evaluated in the 2025 IRP analysis:[2]

Table 1-1 PUD Scenario Descriptions

Scenario	Description
Base Case	Moderate forecast load growth and moderate-cost operating environment
Low Growth	Low forecast load growth and low-cost operating environment

[2] The 2025 IRP scenarios are described in Section 4 – *Scenario & Planning Assumptions*.

High Growth	High forecast load growth and high-cost operating environment
Advanced Technology	High load growth with plentiful access to renewables, energy storage, and emerging technologies at low-cost
Limited Renewable Project Availability	Base load growth with limited access and high-cost environment for REC and renewable acquisition

Four additional sensitivities of the base case were considered to examine one variable's impact on the resource plan. These were high BPA costs, low BPA costs, shallow REC market and a CETA only policy environment. Further descriptions of scenarios and sensitivities can be found in **SECTION 4 SCENARIOS AND PLANNING ASSUMPTIONS**.

Long-Term Resource Strategy

The PUD's Long-Term Resource Strategy must be flexible enough to yield low and reasonable costs for customers across a wide variety of potential futures but be defined enough for the PUD to take concrete actions, especially as it relates to the PUD's need to meet energy and regulatory requirements.

Risk Factors

To address the challenge of developing a resource strategy that is suitable for various futures, the PUD evaluated a wide range of scenarios that encompass many potential risks and assessed the commonalities of the most economic portfolio combinations across scenarios. The risk factors were identified with customers and a cross-departmental team of PUD staff over a four-month public visioning process. Those principal risk factors, and the scenario or sensitivity, that most directly consider them is depicted in Table 1-2.

Table 1-2 Risk Factors and Scenario/Sensitivity Assignment

Risk	Scenario/Sensitivity
Low economic growth and load	Low Growth
High economic growth and load	High Growth
Renewable project development is impacted by policy or transmission limitations	Limited Renewable Project Availability
Renewable energy credits have limited availability for compliance	Shallow Renewable Energy Credit Market
BPA costs change	High BPA Costs, Low BPA Costs
Policy changes impact the PUD	CETA Only Policy Environment, Limited Renewable Project Availability

New generation or storage resources become available at low costs	High Technology

Scenario Results

Staff found a similar set of resource acquisitions proved cost-effective to meet PUD needs across most scenarios. While timing and resource scales differed modestly, core portfolio components remained consistent. The most significant deviation across portfolios came from highest load growth trajectory scenarios and at the latter portion of the study period (2030's and beyond), suggesting that the PUD may have additional time to address unique needs in those scenarios based upon cumulative evidence of load growth. Table 1-3 provides a comparison of key resource acquisition types by category and scenario for the first 10 years of the study period and highlights the relatively narrow range of portfolio variance across scenarios.

Table 1-3 Portfolio Additions in Years 1-10 Across Scenarios

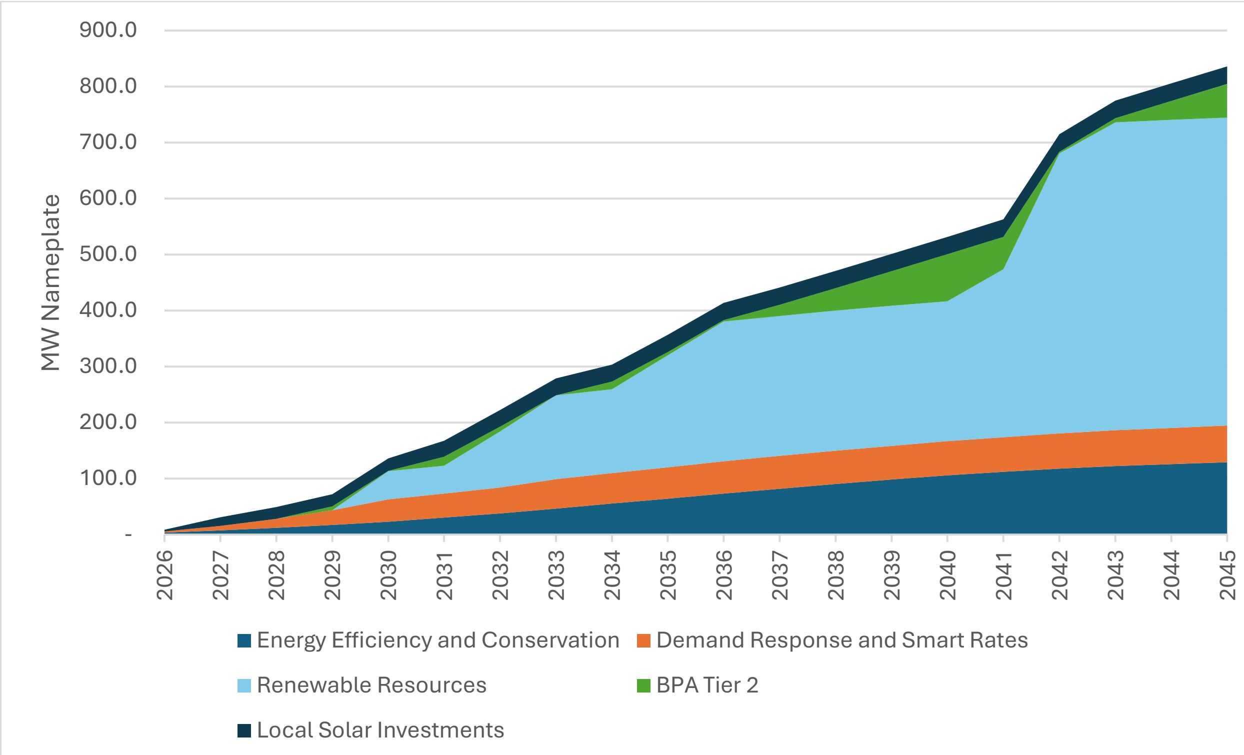
Scenario	Conservation (aMW)	DR & Rates (MW)	Local Solar (Nameplate MW)	Renewable Resources (Nameplate MW)	BPA Long-Term Tier 2 (aMW)	Battery Energy Storage (Nameplate MW)
Base	64.2	56.1	34.0	100	-	-
Low	57.5	56.1	34.0	-	-	-
High	74.9	56.1	34.0	200	-	-
High Technology	64.2	56.1	34.0	150	-	-
Limited Renewable	74.9	57.1	34.0	200	-	25
High BPA Costs	74.9	56.1	34.0	200	-	25
Low BPA Costs	64.2	57.1	34.0	250	-	50

Shallow REC Market	64.2	57.1	34.0	300	-	100
CETA Only Policy Environment	64.2	51.7	34.0	250	-	100

Long-Term Resource Strategy Components

The stability of results across scenarios allows the PUD to consider that the resources added for any planned future will still provide value and meet portfolio needs across a wide range of other scenarios. To establish specific scale and timing estimates for the PUD to plan towards, the Base Case scenario, which represents the expected load, market and existing portfolio resource generation outcomes at the time of publication, was used. The Long-Term Resource Strategy is shown in Figure 1-2 and its component parts are described in the narrative sections that follow. It should be noted that while nameplate is appropriate for renewable resources and local solar investments in the chart, BPA Tier 2 is represented as the annual aMW of Tier 2 purchases, conservation is the energy savings in annual aMW, and Demand Response is represented by peak hour demand savings. These units are displayed together to provide a snapshot of aggregated investments needed for load service.

Figure 1-2 Long Term Resource Strategy Additions (MW)



Conservation

Conservation provides the foundation for the PUD's resource plan, delivering multiple value streams for meeting portfolio needs. The PUD's 2-year, 4-year, and 10-year conservation targets are shown in the figure below. Conservation provides the PUD value by contributing to capacity needs (by reducing load that otherwise would have occurred during peak hours), reducing the PUD's energy needs, reducing transmission costs, and by reducing load associated with regulatory obligations under the EIA and CETA.

Figure 1-3 Conservation Targets (Annual aMW) [3]

2027 (2-year)	2029 (4-year)	2035 (10-year)
7.5	17.0	64.2

Demand Response and Smart Rates

Demand Response and Smart Rate programs provide the PUD with low-cost, within service territory resources to meet peak demand needs and provide regulatory value. The

[3] Conservation targets are expressed at the BPA busbar, cumulatively, such that the 2027 target is the targeted conservation acquired in 2026 & 2027 added together.

development of these programs is highly contingent upon the timing, rollout, and leveraging of the PUD's AMI program. That infrastructure will allow the PUD to access and develop the lowest cost load-shifting programs. The PUD completed a comprehensive Demand Response Potential Assessment in support of this IRP, and additional details are contained in that assessment. The PUD's 2-year, 4-year, and 10-year demand response and smart rates targets (combined as DR targets) are given in the table below and are expressed in Peak Hour Nameplate Capability in MW.

Figure 1-4 DR Targets (Nameplate MW)

2027 (2-year)	2029 (4-year)	2035 (10-year)
8.1	26.6	56.1

Local Solar

The PUD has been successful in developing multiple local solar projects, including community solar projects. The 2025 IRP finds additional local medium-scale solar projects to be cost-effective due to their low transmission and resource support costs, regulatory value, and flexibility in timing and scale. The regulatory value of medium utility-scale solar has increased based on recent Washington State legislation granting a 4 times multiplier on generation from projects under 5MW commissioned before 2030. The total nameplate target is for MW of solar installations not to exceed 5MW increments.

Figure 1-5 Medium Utility-Scale Solar (Nameplate MW)

2027 (2-year)	2029 (4-year)	2035 (10-year)
0	5	10

Renewable Energy Certificates

The PUD uses RECs to comply with the RPS and anticipates using them for CETA compliance. RECs can be acquired with energy from a renewable project, or separately (termed "unbundled") as a compliance instrument only. The 2025 IRP finds unbundled RECs paired with the existing PUD portfolio to be the most cost-effective way to meet compliance requirements, however, the availability of unbundled RECs is uncertain and there may be less available than is needed for compliance purposes. Renewable resource acquisition was found to be a cost-effective way to mitigate unbundled REC supply risks and contribute to load service needs. Unbundled RECs were added in all portfolios studied to augment the existing portfolio and planned acquisitions.

Summary

The totality of the PUD's Long-Term Resource Strategy additions are shown below for 2-, 4- and 10-year horizons. Additional detail and the total resource strategy is given in **SECTION 7 KEY INSIGHTS AND ACTION PLAN**.

Table 1-4 Long-Term Resource Additions Summary

	2027 (2-year)	2029 (4-year)	2035 (10-year)
Conservation (Cumulative Annual aMW)	7.5	17.0	5
Demand Response (Cumulative Peak Hour MW)	8.1	26.6	56.1
Medium Utility-Scale Solar (Cumulative Nameplate MW)	0	5	10
Incentivized Large Customer-Owned Solar (Cumulative Nameplate MW)	15.6	16.9	20.4
Utility-Scale Renewable Resources (Cumulative MW)	0	0	200

CETA Compliance

This is the PUD's first IRP with CETA requirements under the Load-Following product, and as such, it is important to share with the reader how the PUD considered compliance obligations, what the outcomes are forecast to be, and how the PUD considered meeting its requirements analytically.

The PUD projects that in changing to Load-Following, the PUD will have a fuel mix that roughly matches BPA's resource portfolio, historically approximately 92% clean on average. The PUD is still well-positioned for CETA compliance, and the clean energy resources and RECs in the Long-Term Resource Strategy are forecast to be sufficient for CETA compliance.

Action Plan Summary

The following is a summary of near-term actions identified by the 2025 IRP to ensure the PUD can meet the future needs of its customers. Further details of the full long-term resource strategy and action plan can be found in **SECTION 7 2025 ACTION PLAN**.

1. **Acquire 7.5 aMW of cost-effective conservation by 2027**
2. **Develop cost-effective Demand Response & Smart Rates options, maximizing the regulatory and peak management value**
3. **Develop local PUD solar and explore programs for large (>50 kW) customer-owned solar resources**
4. **Perform due diligence on regional renewable energy projects, and prepare for potential procurement activity**
5. **Perform additional analysis on BPA Tier 2 product options**
6. **Ensure compliance with clean energy mandates**
7. **Perform due diligence on local battery energy storage**
8. **Explore partnerships with local fusion energy companies**
9. **Continue to engage in regional transmission policy and planning efforts to ensure sufficient transmission capacity to serve load**
10. **Continue to engage in Organized Markets development**
11. **Demonstrate regional leadership on power, transmission and policy issues**
12. **Continue to build and enhance community engagement on long-term planning**
13. **Continue to advance the PUD's long-term planning tools to capture more risks, opportunities and scenario-planning tools with the goal of achieving lowest reasonable costs for customers.**
14. **Develop a strategy and framework to manage new large load requests**

Organization of the Document

The organization of the 2025 IRP document is as follows:

- Section 1 is this Executive Summary.
- Section 2 describes the PUD, including current load forecast and trends, existing and committed power supply resources, and demand side programs.
- Section 3 discusses the industry's changing dynamics and planning environment, including recently adopted or proposed legislation that may affect utility operations and costs. These set the stage for the IRP planning process.
- Section 4 details the scenarios, range of forecasts and planning assumptions incorporated in the 2025 IRP analysis.
- Section 5 summarizes the analytical framework and planning standards used to examine the PUD's load resource balance and identify future resource need.
- Section 6 describes the portfolio results for the scenarios and the selection of the Long-Term Resource Strategy.
- Section 7 describes the key insights of the 2025 IRP analysis and the near-term Action Plan to implement the selected Long-Term Resource Strategy.

- Appendix A describes the clean energy action plan including the 10-year portion of the long-term resource plans contribution to meeting clean energy goals.
- Appendix B contains a summary of the clean energy implementation plan with a near term 4-year vision for clean energy compliance.
- Appendix C describes the public process for engaging with customers and soliciting feedback in development of the IRP scope.
- Appendix D has been intentionally left blank.
- Appendix E shows the analysis of demand response value drivers based on WA State Bill 5445 giving regulatory value to demand response and smart rates.
- Appendix F describes the emerging supply-side generation and energy storage technologies that were not included in the resource options but are at some stage of development. These technologies are being followed for future inclusion pending commercial developments.

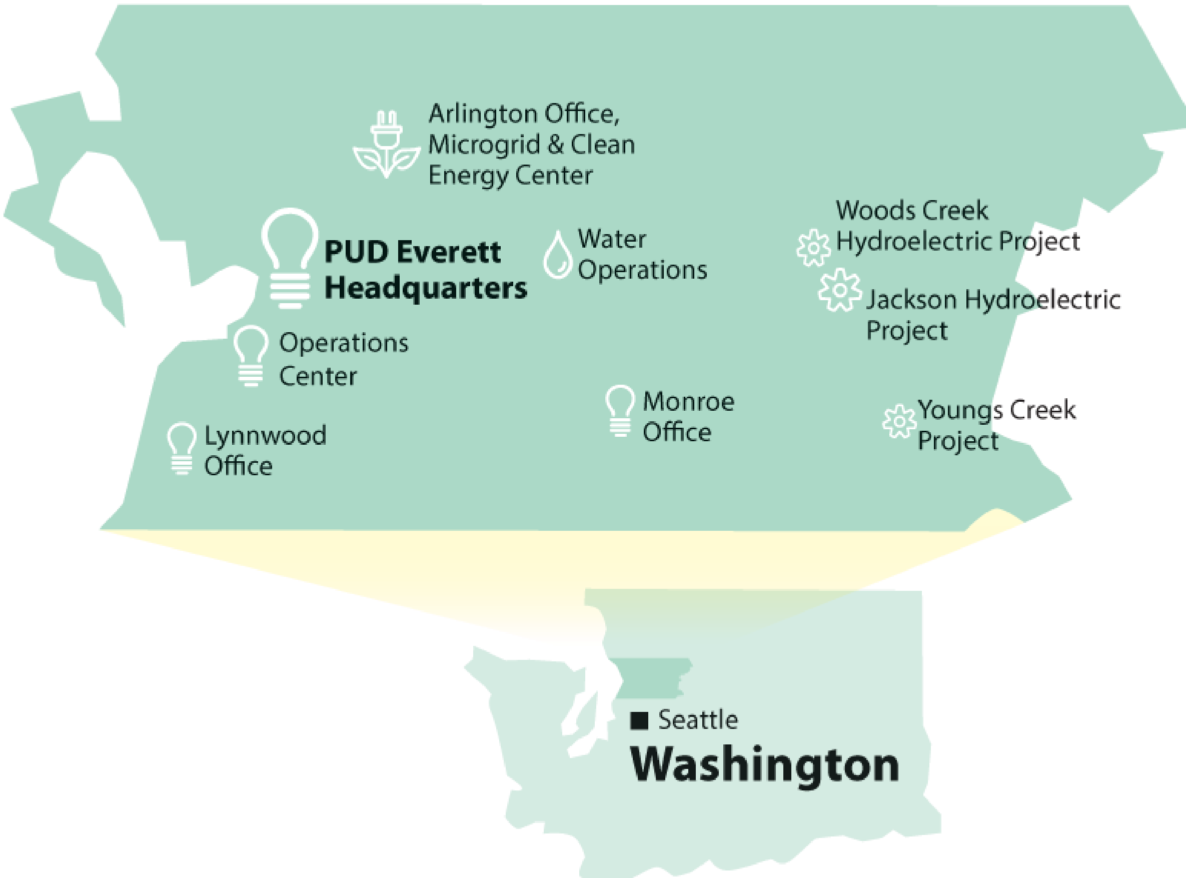
2 Who We Are

The Public Utility District No. 1 of Snohomish County (the PUD) began utility operations in 1949 by purchasing the electric distribution facilities for Snohomish County and the Camano Island portion of Island County from Puget Power & Light. The PUD is the 12th largest public utility in the U.S. and the second largest in Washington state serving more than 380,000 electric customers and more than 23,000 water customers.

The PUD is committed to delivering the best possible service, keeping rates competitive and maintaining the highest levels of reliability for our customers. As stewards of critical community resources, the PUD takes these responsibilities seriously.

The PUD is governed by a Board of Commissioners, which is composed of three members. They represent specific areas of the county and are elected at-large for staggered six-year terms. The legal responsibilities and powers of the PUD, including the establishment of rates and charges for services rendered, reside with the Board of Commissioners. The PUD is a not-for-profit utility and takes great pride in serving our customers in our community.

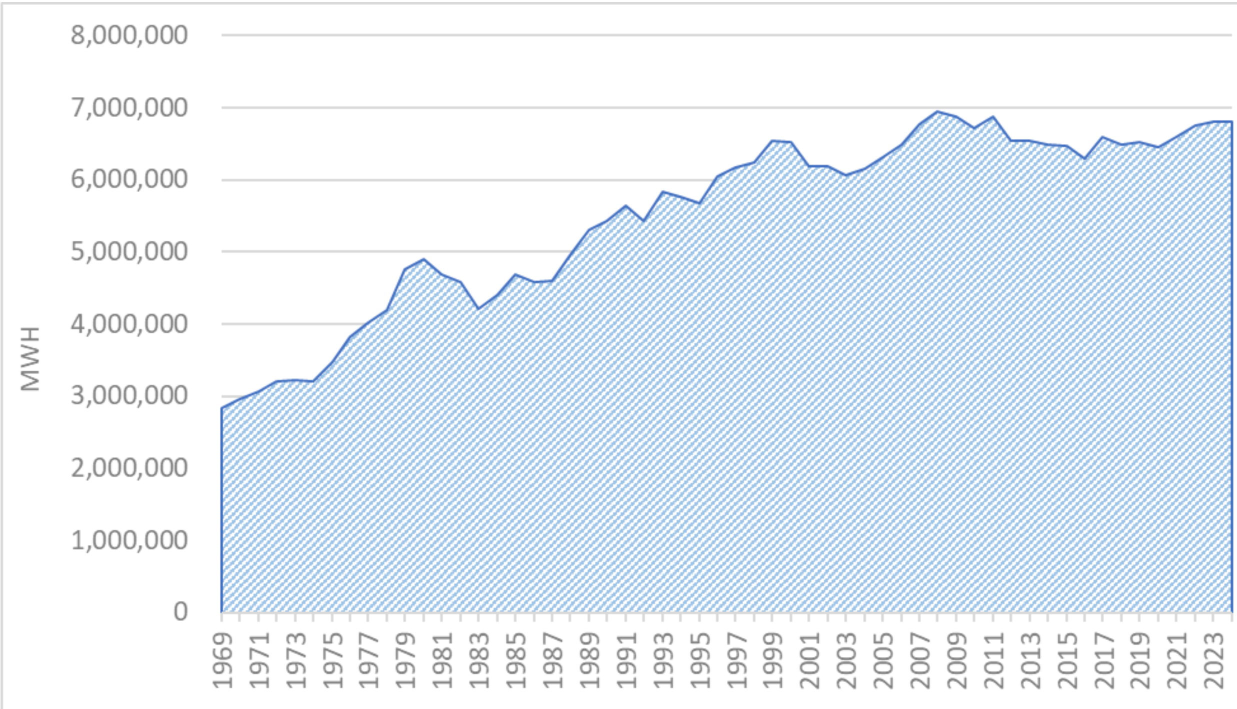
Figure 2-1 Snohomish PUD Service Territory



Load Growth

From 1970 to 2024, the PUD's total load grew at an average annual rate of 1.7%, with residential and commercial loads increasing by 1.8% and 3.5% respectively, while industrial load declined by 0.8% annually. Conservation and energy efficiency have been a key strategy for managing costs and load growth. Between 2010 and 2024, the PUD acquired 133 average megawatts of new conservation. As a result, the adjusted average annual load growth from 2010 to 2024 was -0.03%. This trend is reflected in **FIGURE 2-2 SNOHOMISH PUD HISTORICAL ANNUAL MWH RETAIL SALES**, which shows relatively flat retail sales since 2008, despite significant population and economic growth in Snohomish County.

Figure 2-2 Snohomish PUD Historical Annual MWh Retail Sales



Current Trends Influencing Load Growth

The economic environment in Snohomish County and Washington State remains in a phase of sustained recovery from the impacts of the COVID-19 pandemic. The unemployment rate in Snohomish County has declined significantly—from a peak of nearly 20% during the height of the pandemic in 2020 to 6.1% in June 2025. The leisure and hospitality sectors were among the hardest hit, while high-tech and professional industries were more resilient due to their ability to pivot to remote work environments.

Despite the challenges of the pandemic, the PUD successfully connected approximately 5,000 new premises in 2020, slightly above the pre-pandemic trend of around 4,000 new connections annually. Looking ahead, this pace is expected to continue, with projections of 4,000 to 5,000 new connections per year in response to sustained population growth and development activity. Snohomish County's population is projected to surpass 1 million residents by the 2040 timeframe. This continued growth is fueling strong housing demand across the region, increasing pressure on housing inventory. Along with population and housing expansion, Washington State's clean energy policies are accelerating the adoption of electric vehicles (EVs). Under the state mandate, all new passenger vehicles sold by 2035 must be zero-emission. As a result, Snohomish County expects a significant increase in EV adoption over the coming decade, which will drive rising demand for residential, commercial, and public EV charging infrastructure.

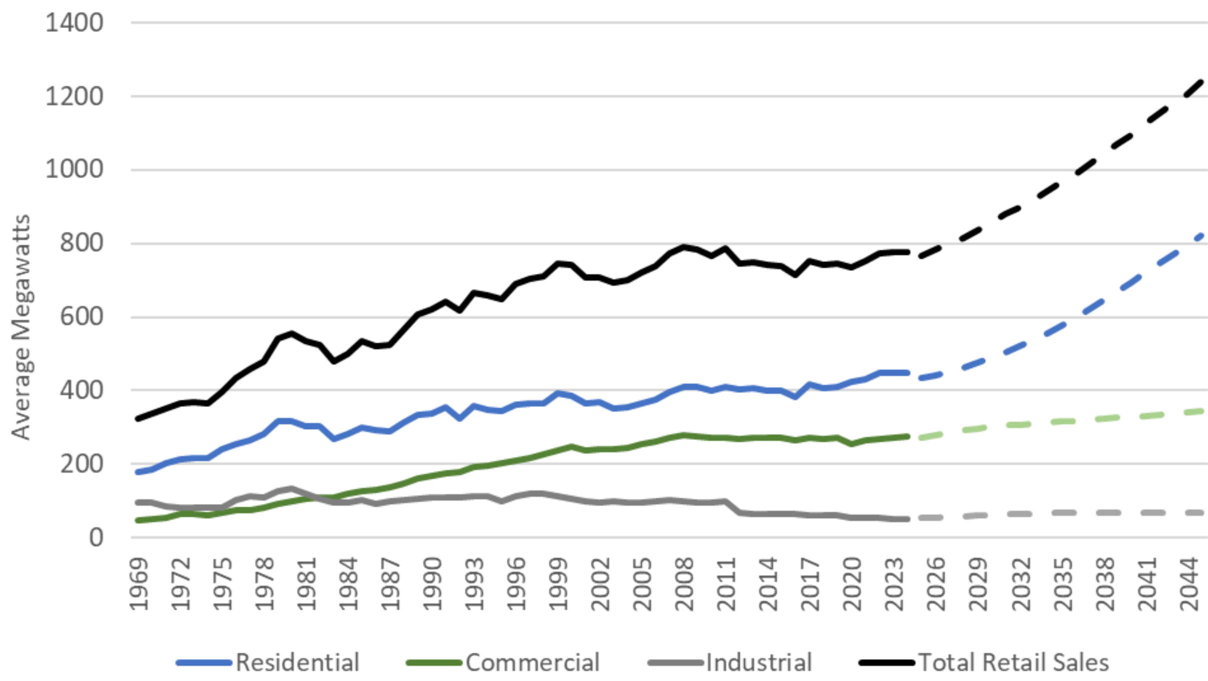
Snohomish County's main employment base remains in aerospace manufacturing, primarily Boeing's Everett Plant, and hundreds of small aerospace companies delivering parts for the 747, 767, 777, and 787 programs. Naval Station Everett, Snohomish County, and Providence Hospital are also major employers in the region. Growth also continues in the biotech sector in South Snohomish County, as well as continued changes to the manufacturing sector in the Everett area and North Snohomish County. The Cascade Industrial Center, which spans from Marysville to Arlington, will be the second largest manufacturing-industrial center in the county. The Port of Everett's development of the Waterfront Place Central and Riverfront is also underway and is expected to provide jobs and easy access to the waterfront. This effort, located east of downtown Everett, will transform the waterfront into a sustainable and unique commercial, recreation, and residential community.[1]

Historical Perspective on Load Growth

Figure 2-3 shows that historically following recessionary periods, the PUD's total retail sales rebound and resume their prior upward slope. In previous recessionary periods, customer demand recovered to meet or exceed pre-recessionary loads. However, recovery from the previous 2008 recession had been markedly different for the PUD, with retail sales generally flat. This finding casts some doubt on the degree to which structural growth in demand should be expected in the period following the Covid-19 economic impact. The flattening of retail sales in recent years is likely due to several factors, such as the culmination of decades of energy efficiency acquisitions and the growing impact of building codes and standards improvements.

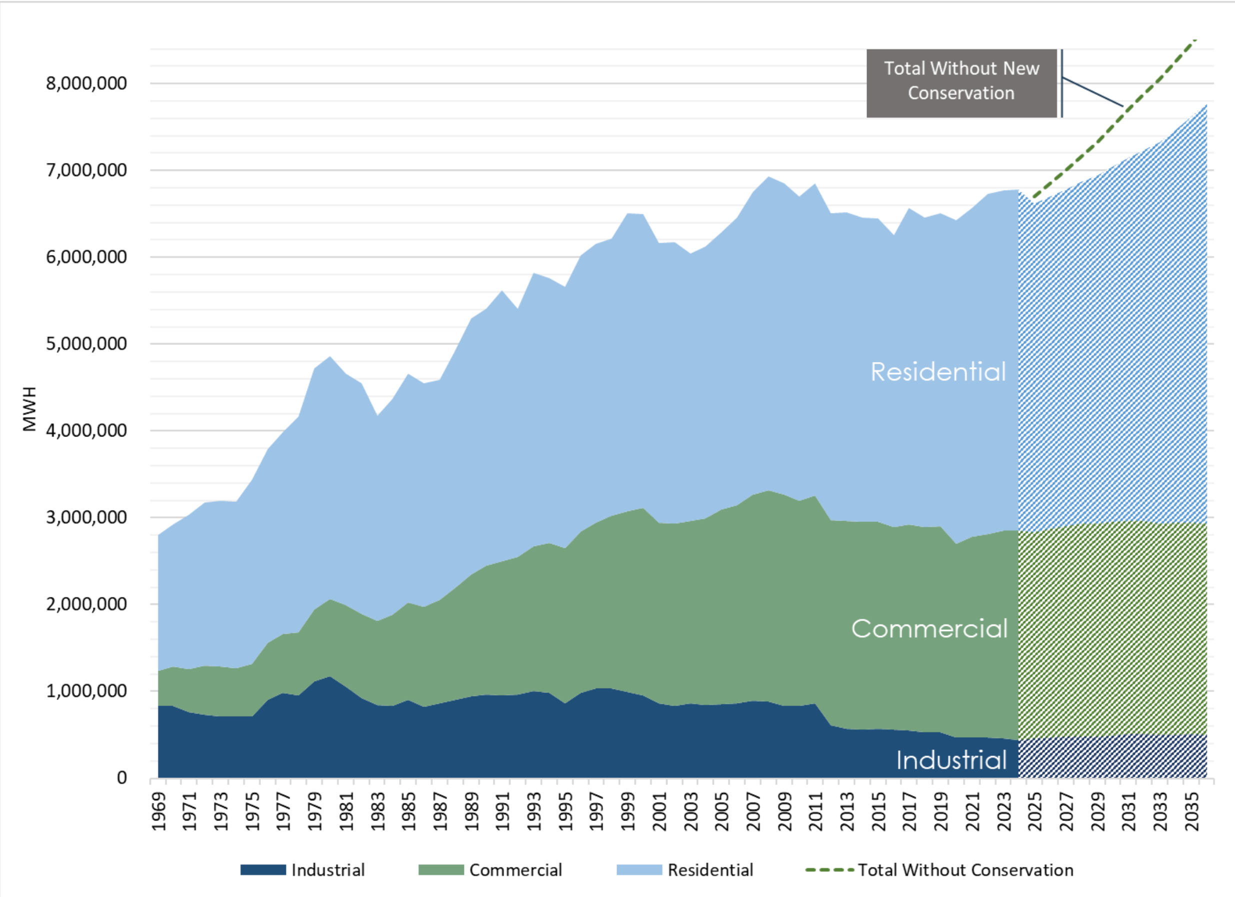
[1] Section 2 – *Who We Are,* discusses the PUD's load forecast methodology and current trends. Section 4 – *Scenarios and Planning Assumptions,* describes the various future socio-economic factors and elements considered in the study scope of 2025 IRP analysis.

Figure 2-3 Historic PUD Annual aMW load by sector before conservation



Despite these considerations the PUD expects to see sustained positive load growth in the foreseeable future, reflecting strong population inflows, a resilient regional economy in the greater Puget Sound area, and the increasing adoption of electric vehicles. This growth is further supported by ongoing development and electrification trends in new housing such as the shift toward electric heating, cooking, and water heating. Together, these factors are reshaping load patterns and supporting long-term growth in system demand. Figure 2-4 shows the impact of these sources of residential load growth in context of overall load growth and the relative growth of other customer segments.

Figure 2-4 Historic Snohomish PUD Load By Sector in Annual MWh



Overview of the PUD's Portfolio

The PUD relies on a diversified power portfolio consisting of a broad range of conservation and energy-efficiency programs, a long-term power supply contract with the Bonneville Power Administration (BPA), PUD owned hydroelectric projects, and PUD owned or contracted small renewable projects. The PUD is a full-requirements customer of BPA and uses the Load-Following power product for most of its long-term power supply.

Existing & Committed Resources

The PUD relies on a portfolio of resources to meet customer demands. These include:

- **Supply side resources**
  - BPA Power Sales Agreement for Load Following
  - PUD-owned generating resources

- Small renewables program and customer-owned generation
- Regional transmission contracts

- **Demand side resources**
  - PUD energy efficiency programs
  - Demand response programs

Existing Supply Side Resources

BPA Power Contract

The PUD meets its load obligations by managing the energy available from the BPA power contract in concert with its owned resources and other long-term power supply contracts.

BPA is a revenue-financed federal agency under the U.S. Department of Energy that markets wholesale electricity to more than 140 utility, industrial, tribal and governmental customers in the Pacific Northwest. Its service area covers more than 300,000 square miles with a population of approximately 14 million in Idaho, Oregon, Washington and parts of Montana, Nevada, Utah and Wyoming.

BPA sells electric power at wholesale rates, which is generated from 31 federal hydroelectric projects in the Columbia River basin, including one nonfederal nuclear plant and several other small nonfederal power plants. The federal hydroelectric projects and the related electrical system are known collectively as the Federal Columbia River Power System (the "Federal System"), which has an expected aggregate output of approximately 9,089 annual average megawatts under average water conditions and approximately 8,135 annual average megawatts under adverse water conditions. The Federal System produces more than one-third of the region's electric energy supply.

Load-Following Product

The PUD currently purchases the Load-Following product from BPA for the contract term of October 1, 2025 through September 30, 2028. The PUD plans to continue purchasing the Load-Following product from BPA on Oct 1, 2028 but will continue to evaluate the best product choice for cost and load service. The PUD purchases more than 90% of its power supply from the BPA under the long-term power contract. The Load-Following product provides firm power service to meet customer load minus dedicated resources with BPA assuming load service planning responsibility for peak loads. This product is scheduled by BPA to serve load but requires a separate service with additional cost to integrate renewable resources. The PUD also switched transmission products from Point-to-Point (PTP) to Network Transmission (NT) to help facilitate the Load-Following power product.

For the duration of the current BPA power contract, BPA determines the total of its customers' loads and the size of the Federal hydro or "Tier 1 System," to allocate costs. This Rate Period High Water Mark process establishes the maximum amount of energy the PUD is eligible to purchase from BPA at cost, or the Tier 1 rate. Under the current contract the size of the Tier 1 System varies due to changes in BPA's system obligations, customer load growth, and maintenance outages and refurbishments to the Federal System. Table 2-1 shows the actual BPA Tier 1 system size and Tier 1 contract allocation amount for the PUD for the 2015 through 2025 period:

Table 2-1 BPA Tier 1 System Size and Contract Allocation

Fiscal Year	BPA Tier 1 System Size (in aMW)	Maximum Tier 1 Available to PUD Rate Period High Water Mark (in aMW)	Actual BPA Tier 1 Contract Allocation to Snohomish PUD (in aMW)
2015	6992	811	755
2016	6983	791	759
2017	6983	791	778
2018	7023	786	729
2019	6866	786	729
2020	7054	795	723
2021	6995	795	723
2022	6802	762	718
2023	6670	762	742
2024	7097	799	742
2025	7029	799	761

After September 2028, the Federal System size will be fixed at 7,250 Average MW reducing the system allocation calculation to only depend on the planned load proportion.

PUD-Owned Generating Resources

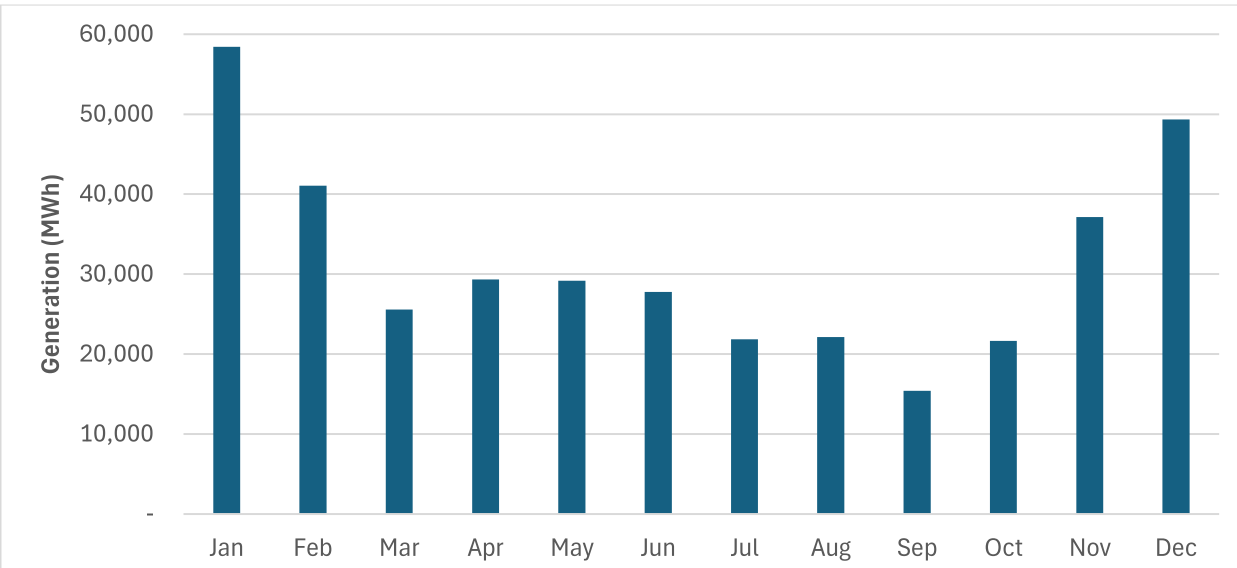
Jackson Hydroelectric Project

The Jackson Hydroelectric Project (Jackson Project) is located on the Sultan River, north of the City of Sultan, and is owned and operated by the PUD. The project has two large 47.5 MW nameplate Pelton generating units and two smaller 8.4 MW Francis generating units for a total nameplate capacity of 111.8 MW. The firm energy for the project, based on the 1940-41 water year, is ~29.5 aMW. The average annual or expected output is approximately 49 aMW. Project output is delivered directly into the PUD's electric system.

The Jackson Project is operated to maximize the revenue generated through the Secondary Crediting Services annually, subject to specified minimum releases of water into the Sultan River for maintenance of fish and the diversion of water into the City of Everett's water reservoir system. An agreement from 1961, with subsequent amendments, established the rights and duties of the City of Everett and the PUD to the uses of water from the project. The City of Everett receives its water supply from Lake Chaplain Reservoir, which the project feeds through the two 8.4 MW generators. The PUD received a new 45-year project license as the sole licensee in September 2011. The new license did not alter how the project is operated. License requirements to maintain stream flows and supply the City of Everett's potable water supply do limit the project's ability to change generation within a day.

For the 2021 through 2024 period, the Jackson Project generated an annual average of 378,972 MWh, with a minimum of 297,996 MWh in 2023 and a maximum of 443,267 MWh in 2021. Figure 2-5 Jackson Average Monthly Generation 2021-2024 below shows Jackson's average monthly generation over the 2021 through 2024 period.

Figure 2-5 Jackson Average Monthly Generation 2021-2024

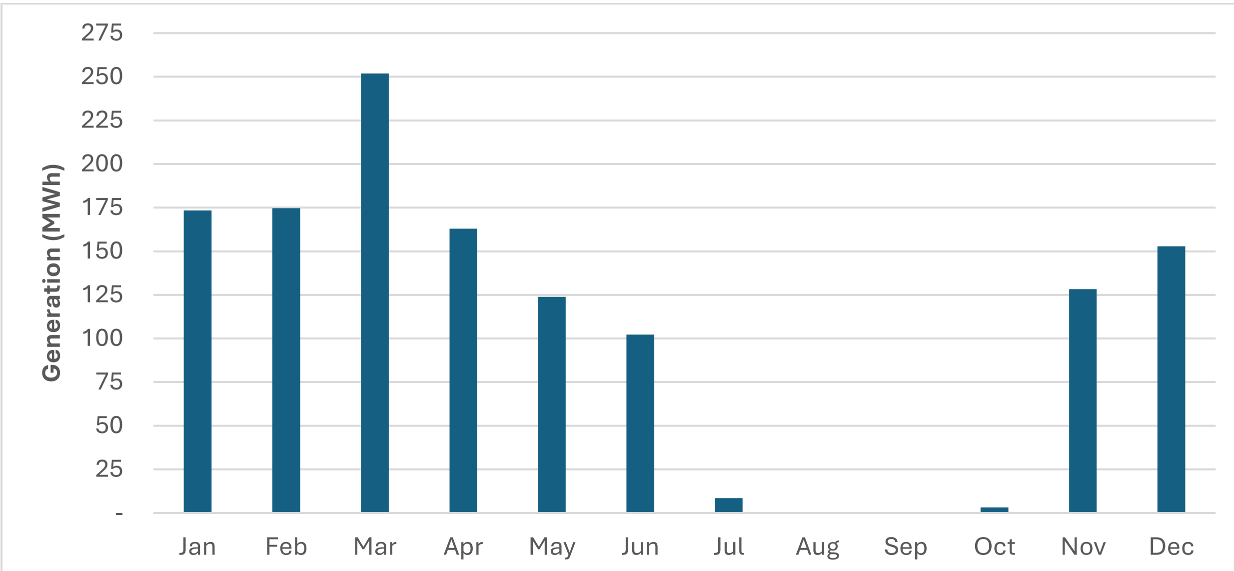


Woods Creek Hydroelectric Project

The Woods Creek Hydroelectric Project is located in Snohomish County, north of the city of Monroe, with a nameplate capacity of 0.65 MW. The PUD purchased the powerhouse and adjoining acreage in February 2008. Prior to its acquisition, the PUD had been purchasing the output from this plant. This project is adjacent to Woods Creek, a tributary of the Skykomish River, with the powerhouse located at the base of a natural impassible barrier to anadromous fish. The majority of its generation is produced between November and April.

Since acquiring the project, the PUD has made numerous engineering and efficiency improvements which has increased annual production from the historical 10-year average production of 497 MWh to just under 1,800 MWh, depending on hydrological conditions. Improvements to the project that increase production without increasing diversion or impoundment are considered “incremental hydro.” Incremental hydro qualifies for Renewable Energy Credits and can be applied toward the PUD’s annual renewables requirement.[4] For the 2021 through 2024 period, Woods Creek has generated an annual average of 1,282 MWh. Figure 2-6 shows the actual generating profile for this resource.

Figure 2-6 Woods Creek Average Monthly Generation 2021-2024



Youngs Creek Hydroelectric Project

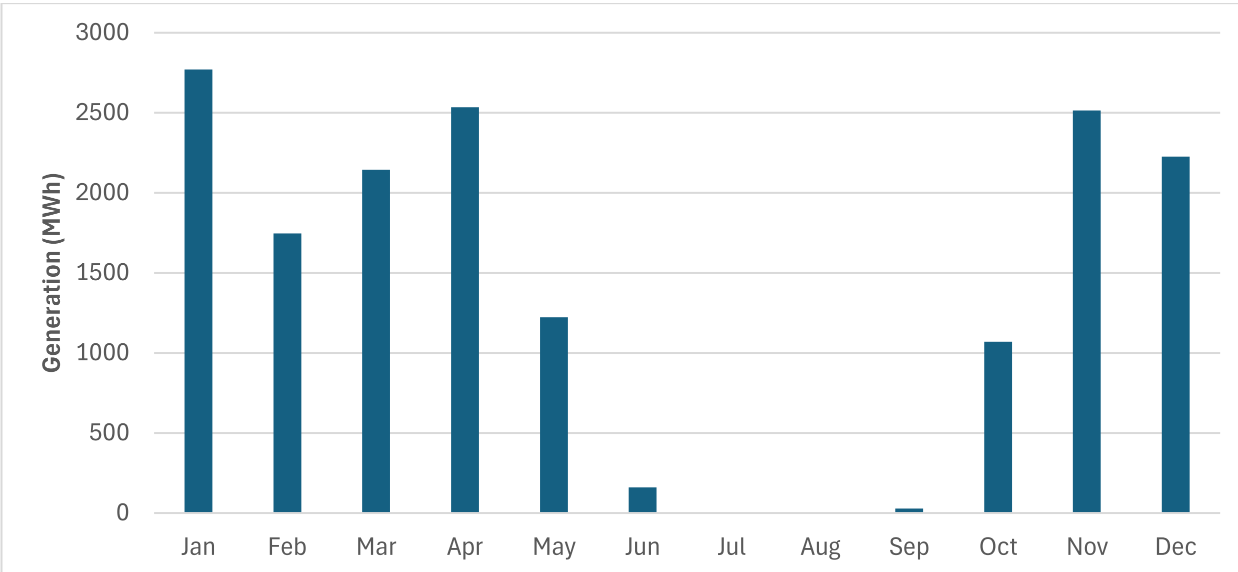
In 2008, the PUD purchased the unconstructed Youngs Creek Hydroelectric Project located on Youngs Creek, a tributary of Elwell Creek near Sultan in Snohomish County. The project is situated above a natural impassable barrier to anadromous fish. Commissioning of this new run of river resource, with single Pelton unit at 7.5 MW nameplate, occurred in November 2011. Youngs creek acted as a project base for Hancock Creek and Calligan Creek and all three projects have similar designs.

Youngs Creek was the first new hydroelectric resource to be constructed in the region in more than 17 years. It is licensed through 2042. For the 2021 through 2024 period, the project

[4] Washington Administrative Code (WAC) Section 194-37-040 (13)(b) provides: “Incremental electricity produced as a result of efficiency improvements completed after March 31, 1999, to a hydroelectric generation project owned by one or more qualifying utilities [see definition of qualifying utility in RCW 19.285] and located in the Pacific Northwest or to hydroelectric generation in irrigation pipes and canals located in the Pacific Northwest, where the additional electricity generated in either case is not a result of new water diversions or impoundments.”

generated an annual average of 16,418 MWh, with the majority generated during the winter and spring months as shown in Figure 2-7.

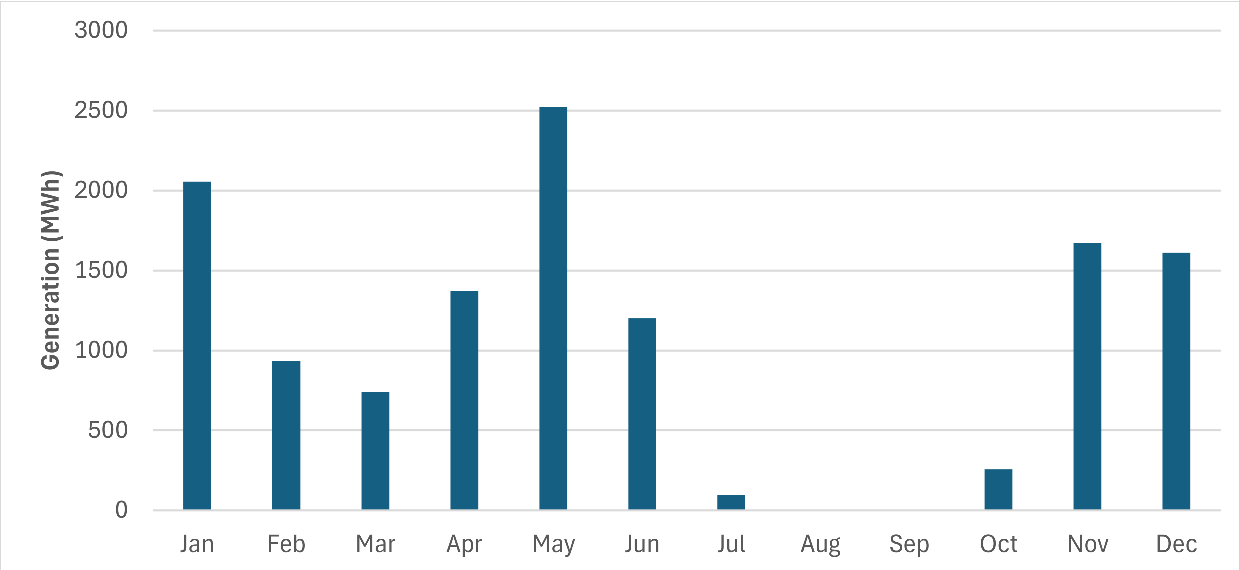
Figure 2-7 Youngs Creek Average Monthly Generation 2021-2024



Calligan Creek Hydroelectric Project

In 2015, the PUD received an original 40-year license for the Calligan Creek Hydroelectric Project located on Calligan Creek, a tributary to the North Fork Snoqualmie River in King County. The project is located above Snoqualmie Falls, a natural barrier to anadromous fish. Construction on this run of river 6.0 MW Pelton unit began in 2015 and began commercial operation in February 2018. For the 2021 through 2024 period, the project generated an annual average of 12,464 MWh, with the majority generated during the winter and spring months (Figure 2-8). The output of this project is currently sold on a short-term basis until October 2028.

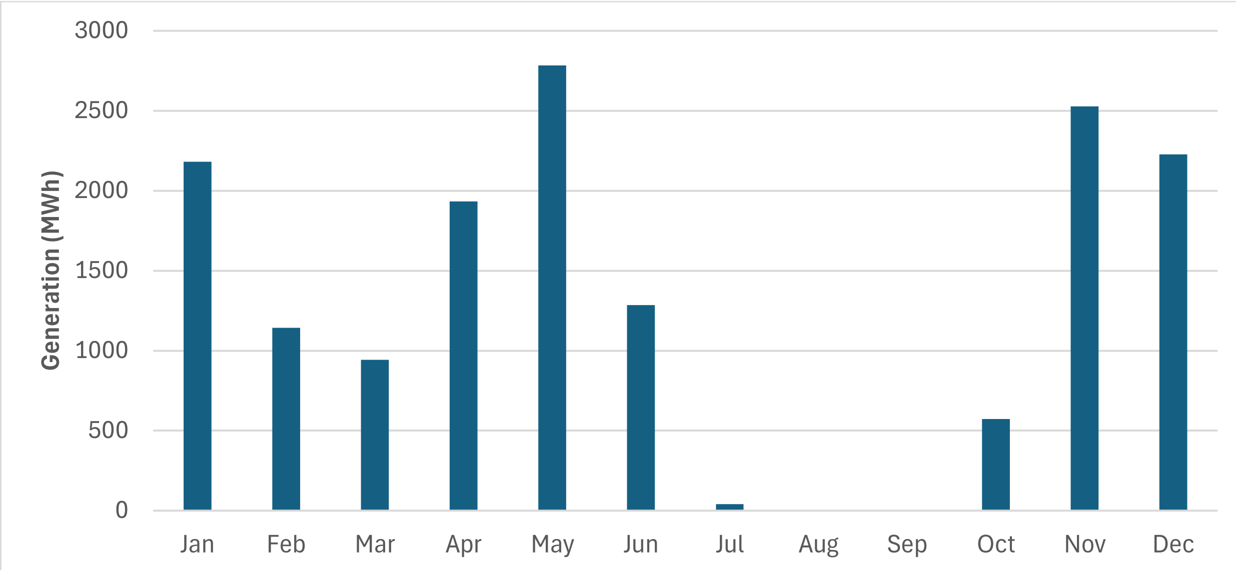
Figure 2-8 Calligan Creek Average Monthly Generation 2021-2024



Hancock Creek Hydroelectric Project

In 2015, the PUD received an original 40-year license for the Hancock Creek Hydroelectric Project located on Hancock Creek, a tributary to the North Fork Snoqualmie River in King County. The project is located above Snoqualmie Falls, a natural barrier to anadromous fish. Construction on this run of river 6.0 MW facility with one Pelton unit began in 2015 and began commercial operation in February 2018. For the 2021 through 2024 period, the project generated an annual average of 15,641 MWh, with the majority generated during the winter and spring months (Figure 2-9). The output of this project is currently sold on a short-term basis until October 2028.

Figure 2-9 Hancock Creek Average Monthly Generation 2021-2024



Arlington Microgrid & Community Solar

In 2017 the PUD announced the Arlington Microgrid (AMG) Solar Array as part of its new local office complex in Arlington, Washington, located east of the Arlington Municipal Airport. This facility is a demonstration testbed for several distributed energy technologies interconnected to be self-sustaining if islanded from the electrical grid.

The project was funded in part through a Clean Energy Fund II grant provided by the Washington State Department of Commerce. The microgrid project consists of a:

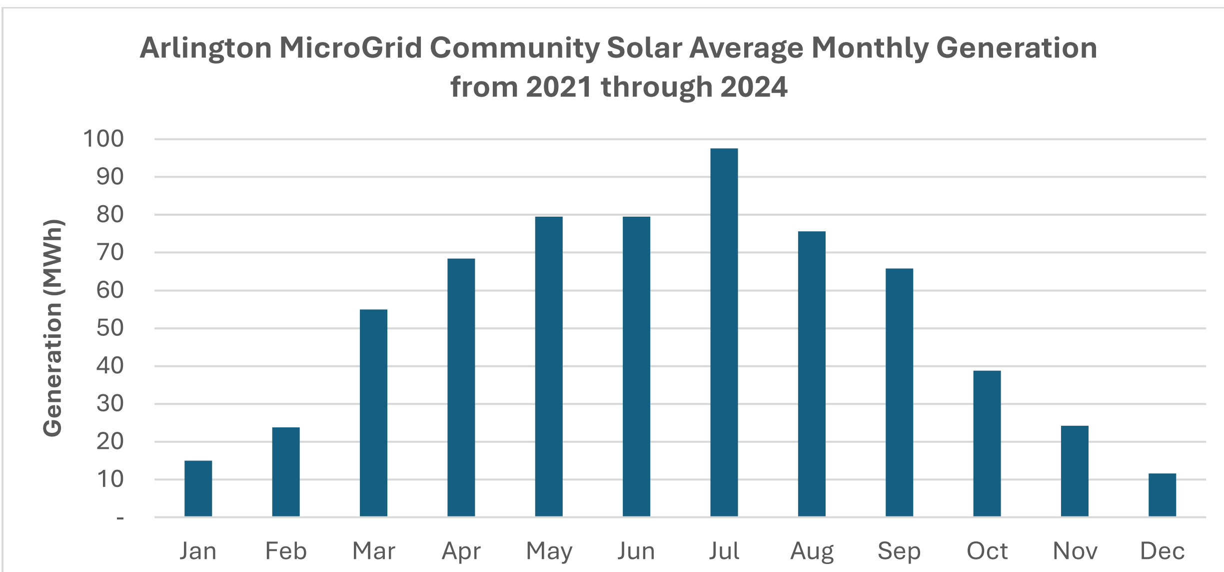
- 500 kW utility scale solar array
- 1000 kW/1500 kWh lithium-ion battery
- Two vehicle-to-grid (V2G) charging systems with connected electrical vehicles
- Clean Energy Center (CEC) to provide the load and demonstration area
- Backup data center for PUD information technology resilience.

These components are interconnected and controlled via a central control system for microgrid operations and connect with the North County Office opened in February 2025. The battery storage system may be called upon by the PUD as needed and will support microgrid operations in the event of loss of the PUD grid connection. The vehicle to grid (V2G) chargers provide an additional source of energy and provide testing for larger scale V2G applications. The PUD is currently participating in a solar smoothing and balancing pilot with

BPA utilizing the renewable plus storage to understand the impacts of storage on renewable output.

The solar array at the AMG was designed and built as a community solar project to support the PUD's clean renewable energy development efforts while providing opportunities for PUD customers to participate and benefit from solar energy generation. Customers were given the opportunity to purchase or lease "shares" of the output of the solar project without requiring their own rooftop, to fund, or install their own solar panels. This aspect of the project was highly successful with 8100 units offered at 1/5 of a panel each. All units were sold over the course of several weeks and over 500 customers participated. The community solar project is expected to last 20 years.

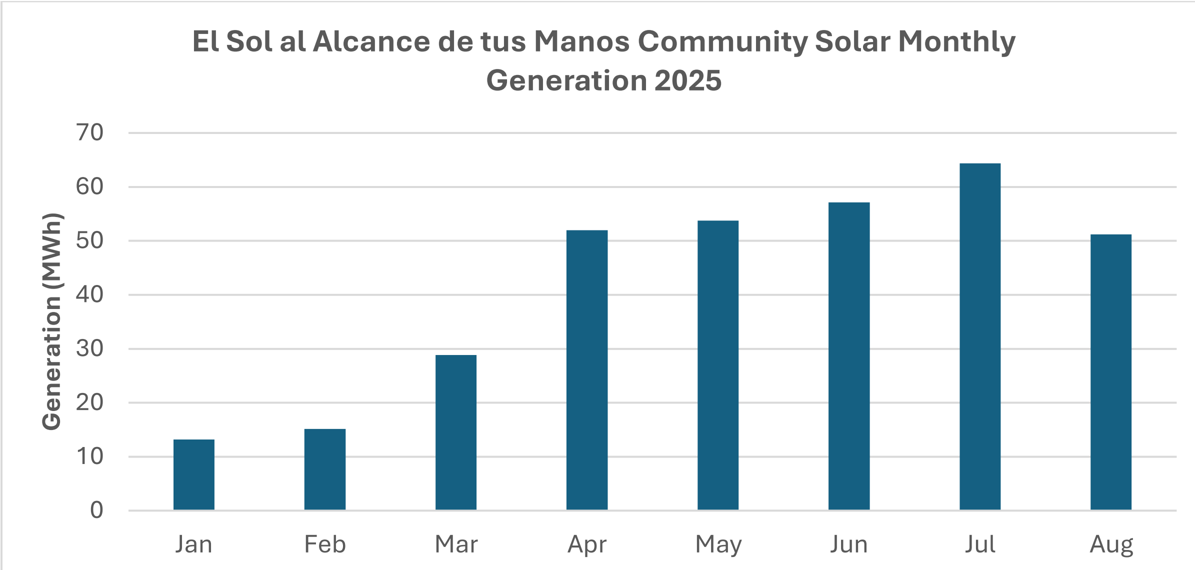
Figure 2-10 Arlington Solar Average Monthly Generation 2021-2024



El Sol al Alcance de tus Manos - South Everett Community Solar

The PUD received a grant from the Washington State Clean Energy Fund (CEF) to build a solar project in south Everett to generate funds for the PUD Community Energy Fund administrated by St. Vincent de Paul. The total project is 400 kW and was completed in December of 2024 at the Walter E Hall Park facility in Everett. Project generation through August of 2025 is included in Figure 2-11 below. Forecast generation is expected to match the shape of the Arlington Solar Project.

Figure 2-11 El Sol al Alcance de tus Manos Monthly Generation Jan - Aug 2025



Long-Term Power Supply Contracts

The PUD has several long-term contracts for energy, each associated with a specific generating resource. The PUD has no ability to shape deliveries under these contracts.

Hampton Lumber Mill – Darrington Cogeneration Contract

In 2006, the PUD executed a 10-year contract with Hampton Lumber Mills-Washington, Inc., for 100% of the electrical output from the 4.5 MW cogeneration project that utilizes wood waste. The project is a primary employer for residents in the town of Darrington, WA. The project began commercial operation in February 2007 and produces approximately 2 aMW. The contract was amended in December 2011 to reflect acquisition by the PUD of both the energy and RECs from the project for the 2012 through 2016 term; a 2016 amendment extended the contract term through 2025 which was further extended to 2028. This project is recognized as an eligible renewable resource under the EIA and qualifies for the two times distributed generation multiplier for every MWh generated.

Packwood Lake Hydroelectric Project

This small hydroelectric project is located at Packwood Lake, 20 miles south of Mount Rainier in Packwood, Washington, and began operating in 1964. This project is managed and operated by Energy Northwest and has a nameplate capacity of 27.5 MW. The PUD is a participant in this project and contracts for a 20% share, or 1.3 aMW, on a firm energy basis. Since October 2011, the PUD has been taking delivery of its 20% contractual share, which it plans to maintain for the foreseeable future. The PUD's 20% share of the project's output has averaged just under 20,000 MWh for 2021 through 2024 period.

Small Renewables Program

The Small Renewables Program was adopted by the Board of Commissioners in August 2011 to encourage development of customer-owned, distributed generation inside the service area. The program established a standard methodology for determining the price the utility may pay for the energy and environmental attributes produced by the customer-owned resource. The contract term ranges from one to five years. Participation in this program is limited to renewable resource technologies between 100 kilowatts and 2 megawatts (MW) nameplate, with a total program limit of 10 MW aggregated nameplate capacity.

Customer-owned Renewables

The PUD introduced its Solar Express program in March 2009 to incentivize the development of renewable distributed generation by residential customers. This program sunset for new enrollments at the end of 2017 after having reached a total of 1,167 photovoltaic systems and a total of 11.3 MW nameplate of installed rooftop solar. In aggregate, these PV systems produced 6,988 MWh in 2024. Despite the sunset of the Solar Express program, the PUD continues to interconnect customer-owned, generally rooftop, distributed generation systems upon request. To date customers have installed over 47MW DC of nameplate solar across over 5000 installations. In 2024 customers installed close to 5MW DC nameplate solar over 550 installations.

Firm Transmission Contracts

Until October 2025 the PUD utilized long-term firm Point-to-Point (PTP) transmission on BPA's system. This firm transmission was used to schedule and deliver power from the source of the generation to the homes and businesses in Snohomish County and Camano Island.

When the PUD elected to change its power product to Load-Following it also changed its transmission product to better fit its BPA power product; the PUD now purchases Network Transmission (NT). NT is a transmission product that allows the PUD to designate Network Resources and Network Loads. BPA then optimizes and manages its transmission system to provide firm capacity for delivering those designated resources to the designated loads in accordance with Part III of BPA's current Open Access Transmission Tariff.

This is contrasted from the PTP product, which provides a set of fixed paths for the customer to manage. While the PUD expects to fully serve its load utilizing NT transmission, the PUD currently maintains contracts for 580 MW of firm point-to-point capacity with BPA. These contracts include 7 different points of receipt (where BPA picks up power for the PUD) and 9 points of delivery (where BPA will deliver power for the PUD). The point-to-point transmission services can be used for marketing power sales and market connections as NT does not allow sales or remarketing of resources.

The contract term expirations for the PUD's firm point-to-point contracts with BPA range from 2026 through 2044; under BPA's transmission business practices, said contracts are eligible for the PUD to request renewal (rollover rights) with a first right of refusal.

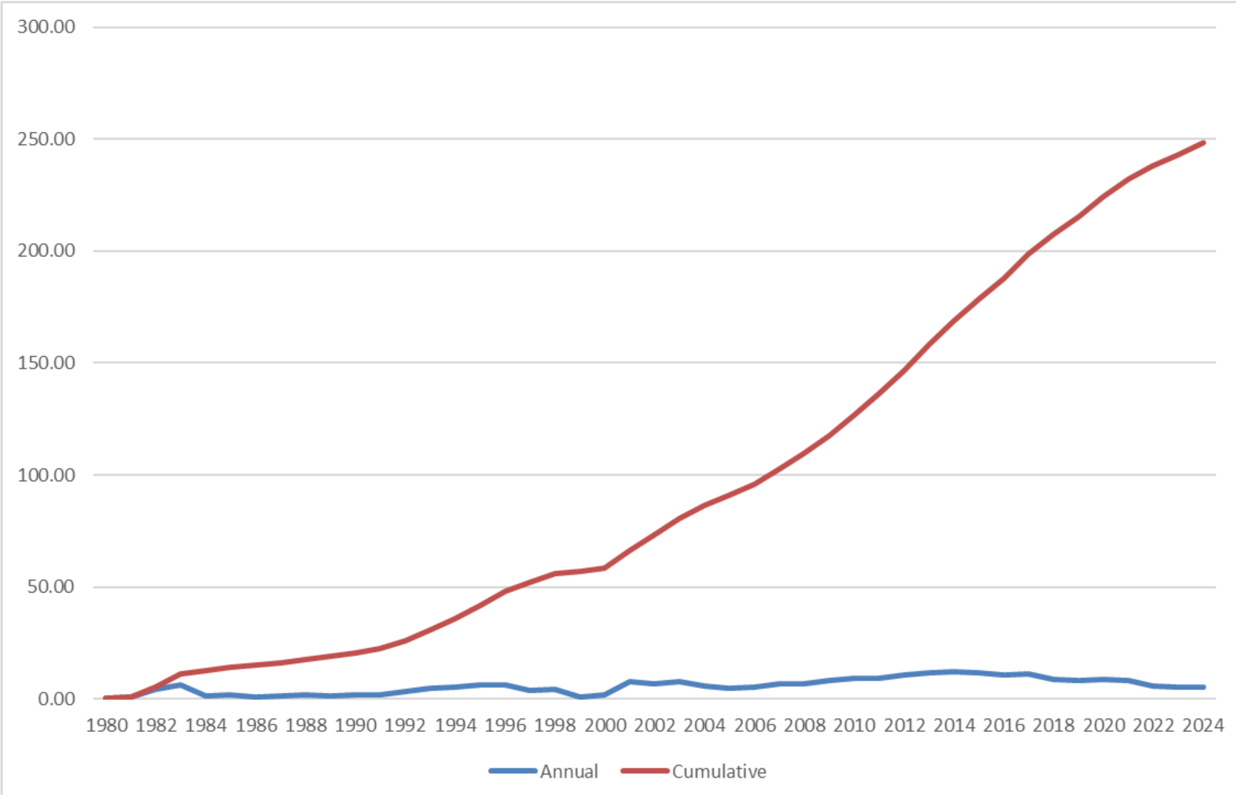
Existing Demand Side Resources

Conservation

The PUD has actively engaged in conservation and demand-side management for over 45 years. Since 1980, conservation and energy efficiency programs have resulted in the cumulative acquisition of almost 250 aMW of conservation resources, or enough to power more than 80,000 homes annually. Figure 2-12 shows the gross annual and cumulative savings accomplishments for the PUD through 2024:[5]

[5] The cumulative savings calculation does not include degradation of savings as energy efficiency measures reach the end of their useful life.

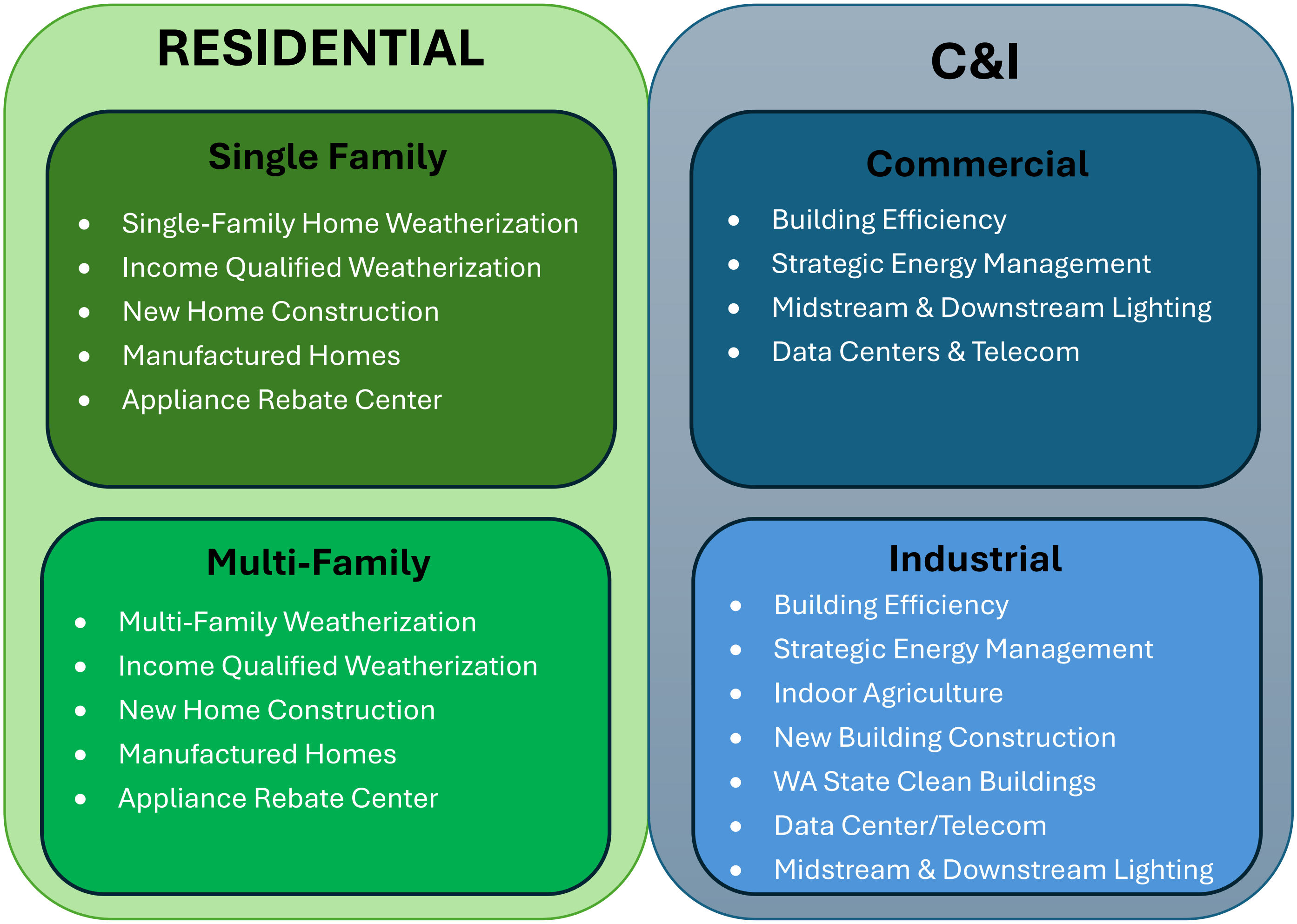
Figure 2-12 Annual and Cumulative Conservation Achievements 1980-2024



The acquisition of new conservation through energy efficiency programs encourages customers to use energy more efficiently, which can defer the acquisition of new supply side resources or reduce the need for BPA Tier 2 energy, postpone the need for new transmission and distribution system upgrades, create value for customers, increase affordability for households, and reduce operating costs for businesses. Conservation is a low-cost resource with minimal environmental impacts.

The PUD offers financial incentives, technical assistance, and educational services for all customer classes. For residential customers, the PUD provides a comprehensive set of energy efficiency programs targeting single and multi-family residences, new construction, and low-income households. Financial incentives are offered for efficiency products including new heating systems, window and insulation upgrades, and home appliances. For commercial and industrial customers, the PUD offers financial incentives and technical assistance to help reduce energy use and annual operating costs. Efficiency products include HVAC, high-efficiency lighting, insulation, process load efficiencies, motors, and equipment controls. highlights key programs and the sector served. Figure 2-13 highlights key programs and the sector served.

Figure 2-13 Energy Efficiency Programs by Target Sector



Program Innovation

In addition to the PUD's traditional conservation programs, the PUD actively seeks out new approaches to markets and emerging technologies. Examples include:

- In partnership with Snohomish County, the PUD secured state matching funds to help improve efficiency for income qualified housing.
- With grant funding from Washington State the PUD provided over $5 million to 1,429 households for energy efficient appliances. The PUD was responsible for nearly half of the households served by the program across the state.
- With market transformation in efficient lighting, the PUD was able to revise its incentives to focus on how best to increase other efficiency opportunities for its commercial and industrial customers. Savings from these other areas can reduce peak demand periods and aid in reducing the PUD's energy needs.

- The PUD recently added numerous new technologies to its program offerings. Emerging products such as direct outside air systems for HVAC, electric hybrid water heaters, high efficiency control systems, and advanced lighting controls provide exciting new opportunities for energy savings and often provide important secondary benefits to customers.

Community Programs

The PUD places high value on offering programs and measures to serve all customers in our community. Recently, staff worked with the NWPCC to study whether the PUD's programs were reaching all customers and markets. Specific attention was given to difficult to reach populations (income qualified customers, multifamily tenants, manufactured home dwellers, small business owners, commercial tenants, and industrial customers). In general, the study showed that most of the hard-to-reach markets were well served by the PUD's energy efficiency programs. Income qualified residential customers participated at rates roughly equal to their distribution in the customer population. Manufactured home dwellers and rural residential customers had proportionally high participation rates. As a group, small business owners, commercial tenants, and industrial customers, participated proportionally throughout PUD's service territory.

Regional and National Efforts

The PUD remains actively engaged in regional and national conservation activities to identify new technologies, develop new delivery strategies and affect policy related to energy efficiency and conservation.

- The PUD actively participates and provides financial support for market transformation efforts through the Northwest Energy Efficiency Alliance, Consortium for Energy Efficiency and the Electric Power Research Institute.
- The PUD is a member of the Regional Technical Forum and the Snohomish County Sustainable Development Task Force and supports the Pacific Northwest Integrated Lighting Design Labs.
- The PUD actively participates in the Conservation Resources Advisory Committee tasked with reviewing and the development and review of the conservation supply curves developed by the NWPCC in their periodic regional Power Plan releases. The PUD supports establishing achievable energy efficiency targets and recognizes the need to conduct research, development and demonstration activities to ensure a sustainable pipeline of future energy efficiency resources.

Demand Response Program and Strategy

Demand response involves the development of programs, pricing structures and technologies to influence when and how customers use electricity. By shifting electricity demands from peak hours when loads are highest to hours of lower loads, the PUD can reduce its costs and maintain or increase reliability, all of which can reduce customers' power bills. Demand cost management under the BPA Load-Following product represents a high value vector of cost mitigation. The BPA rate structure determines the relative value of energy on a monthly diurnal basis coupled with the peak hour demand cost.

Demand response programs take multiple forms: dispatchable load controls, scheduled load controls, voluntary calls to action, and price incentives. Dispatchable load control programs give utilities the ability to call on resources without any action by the customer. Dispatchable resources are often available within 10 or 15 minutes after being requested or "dispatched" by a utility. Scheduled load control programs require customers to temporarily change business processes and typically require advance notice by the utility ahead of a request for load reduction.

The PUD's adopted 2023 IRP included an action item to develop time-of-use (TOU) rate options for customers and to explore cost-effective demand response programs. The IRP is aligned with the PUD strategic plan priority to **Enhance and Evolve Customer Experiences** by *giving our customers increased flexibility and control over their usage and costs*. The ConnectUp program deployment of automated meters ramped up from 2024 through 2025 with expected full deployment by 2027. Time of use rate options have been determined to be a cost-effective solution for several IRPs but rely on the ConnectUp program.

Other demand response efforts in the Northwest were driven primarily by the need to: 1) demonstrate technology; 2) test customer acceptance; and/or 3) explore demand response costs and potential. National programs – largely from summer peaking utilities – were found to be more mature yet still considered 'developing,' and not fully mature.

In 2021 the PUD launched three pilot smart rate options, FlexTime, FlexResponse and FlexPeak programs to develop understanding of customer behavior under various smart rate options. The FlexTime program used time-of-day rate designs to encourage load shifting, FlexResponse used incentives on devices to allow calls for load reduction during critical times and FlexPeak using critical peak pricing notifications to reduce peak load in critical conditions.

Demand response is viewed as having the potential to serve as a reliable resource for peak demand cost management. Demand response may also impact and potentially defer transmission and distribution investment needs over time, as well as serve as a customer engagement offering. A comprehensive strategy will incorporate the benefits and assess the value that demand response products and programs can bring to the PUD and power supply portfolio. This effort is expected to develop specific demand response options - with quantified cost and performance attributes – that can be incorporated into the list of available demand side resource options for future IRP processes.

3 The Planning Environment

Part of the process for determining the best way to meet future customer needs and demands involves establishing an environment in which the PUD sees itself operating. This environment must consider both the current landscape of policy and trends and how they may evolve over time. To evaluate these trends, the more significant factors have been categorized by their sphere of influence on the PUD:

- The PUD's Strategic Priorities
- The Puget Sound Economy
- BPA
- Energy Policy and Regulatory Requirements
- Electric Industry Regional Efforts

These factors all inform and influence the scenarios and sensitivities to be studied in the IRP.

PUD's Strategic Priorities

The Board of Commissioners expects the PUD to deliver power and water to its customers in a safe, sustainable, and reliable manner while successfully navigating complex changes in our industry. The PUD accomplishes this by empowering its teams to provide quality service to its community and prudently managing costs while investing for the future. The Strategic Priorities, adopted by the Commission in 2023 and supported by specific objectives and initiatives in the PUD's 2023-2027 strategic plan, are designed to support the PUD's mission of providing quality water and electric energy products and services and include a distinct focus on 5 key areas:

1. Bolster operational reliability and resiliency
2. Enhance and evolve customer experiences
3. Actively help our communities thrive
4. Build a sustainable future with our communities
5. Create a culture and capabilities needed for the future.

The IRP's long term resource strategy and action plan have direct impact on the PUD's ability to achieve the strategic priorities. It is imperative that the two plans are synergistic in their focus and long-term objectives. Below are specific strategic objectives within each priority the IRP supports or impacts.

Figure 3-1 IRP Impacts on Strategic Priorities

Strategic Priority	
1. Bolster operational reliability and resiliency **1.3 Ensure resource adequacy by expanding and protecting resources** **1.4 Preserve exceptional customer value**	The IRP has a foundational role in ensuring resource adequacy by strategically assessing resource needs, efficiently managing existing resources and acquiring new resources needed to meet current and future needs. This dual approach of expansion and preservation ensures that the PUD can deliver cost-effective, reliable service while adapting to evolving environmental, economic, and regulatory conditions. Including demand-side and supply-side resource options gives the IPR a comprehensive suite of options to meet customer requirements.
2. Enhance and evolve customer experiences **2.3 Give customers increased flexibility and control over their usage and costs**	The IRP includes demand-side resources as potential resources which partner with our customers for energy and demand management. Conservation investments help both PUD customers control their costs and help ensure the PUD uses its existing low-cost energy most efficiently. Demand response rates and programs are offerings the PUD values for managing its own costs while customers employing these demand response options gain additional control over their own costs for mutual benefit.
3. Actively help our communities thrive	The IRP was scoped collaboratively with customers through an extensive public engagement process that gave customers multiple opportunities and avenues to share their perspectives. Feedback from

3.1 Strengthen our community connections **3.2 Support the economic vitality of our communities**	customers is included in the scoping of the IRP study The IRP includes supply and demand side resource options that result in investments in Snohomish County and Camano Island and supports the local economy. The IRP has included conservation investments as a resource of choice for many years due to the localized benefits of resources developed in Snohomish County and Camano Island. Transmission and regulatory benefits for local resources are included in the least-cost analysis.
4. **Build a sustainable future with our communities** **4.2 Help our customers and communities achieve their goals**	The IRP follows the PUD guidelines and directives that only sustainable energy investments are considered. The customer feedback received showed support for clean energy resource options in the IRP. Conservation measures ensure the PUD takes full advantage of the existing clean cost-effective portfolio and maintains the environmental value of the PUD's portfolio.
5. **Create the culture and capabilities needed for the future** **5.3 Increase organizational alignment and effectiveness**	The IRP uses a deliberately collaborative process relying on a cross-functional team of subject matter experts ensuring the resource decisions are well vetted and aligned with other efforts across the organization. Finding synergies between organizational efforts and resource planning is advantageous to organizational investments and initiatives and ensures widespread organizational support for the IRP action plan.

The Economy – Puget Sound and Beyond

In 2024, the Puget Sound region experienced an adjusted 0.9 percent increase in employment, with a similar expected growth of 0.6 percent in 2025[6]. However, expectations of economic growth in 2025 are tentative due to the uncertainty surrounding persistent inflation and the Federal Reserve's future decision to hold or lower rates. From June 2024 to June 2025, the Consumer Price Index for both the Seattle area and the nation have increased by 2.7 percent. Retail sales have increased by 5.61 percent in the region from 2024 to 2025, having steadily recovered from the pandemic. While retail sales growth is forecasted to increase by 4.63 percent in 2025 to 2026, shifting consumer sentiment due to future price uncertainties may quickly change this forecast.

In May 2025, the unemployment rate in Snohomish County was 4.3 percent[7], in line with the national unemployment rate at 4.2 percent[8]. However, the Puget Sound region is forecasted to experience increased unemployment levels at 5.0 percent by the end of 2025, as several major employers in the region have announced layoffs.

Financial and Regulatory Framework

When the PUD changed its BPA long term power product to Load-Following, the costs and risks of power service changed as well. BPA is required by statute to provide load service for the PUD's total net requirements including hourly peaks and annual load growth which fundamentally changes the framework under which the IRP operates by removing load service risks at either the hourly or annual metric. Because BPA is obligated to provide load service, the risks to the PUD in the future are primary financial, stemming from increased BPA exposure, new resource costs, or regulatory compliance risks associated with state clean energy legislation. The new IRP structure seeks to minimize these risks.

BPA

BPA is a significant supplier of power to the region; as such, its success and long-term viability are of great importance to public utilities like the PUD and its customers. When the PUD transitioned to Load-Following, the PUD's reliance on BPA for its power needs increased. Ensuring access to low-cost clean federal energy represents a high priority for the

[6] Western Washington University Center for Economic and Business Research. The Puget Sound Economic Forecaster. June 2025
[7] US Bureau of Labor Statistics. Retrieved July 24, 2025. https://www.bls.gov/news.release/archives/laus_06242025.pdf
[8] Western Washington University Center for Economic and Business Research. The Puget Sound Economic Forecaster. June 2025

PUD. BPA costs are an important driver for PUD portfolio costs and two sensitivities surrounding BPA costs are studied within the base case to understand the impacts of changing BPA costs, either increasing or decreasing.

Because BPA derives a significant portion of its generation from hydroelectric facilities on the Columbia River, the Columbia River Treaty between Canada and the United States governing water and power rights on the Columbia River should be addressed. While the treaty is currently under review at the federal level, any potential changes would be speculative and are not considered in the IRP. As the treaty changes, future IRPs and IRP updates will include any resulting changes to hydroelectric generation forecasts.

Post 2028 Contract

The PUD's long-term power contract with BPA expires on September 30, 2028, and the PUD, along with the other Pacific Northwest public utilities, negotiated with BPA for a new long-term power contract. In 2020 BPA launched the Provider of Choice (POC) initiative to engage its customers on the structure of the Post-2028 contract. The results of the POC public process were published as an Administrator Record of Decision in March of 2024. Contract details are largely similar to the prior 20-year power contract with impactful changes reflected in the IRP study. The new POC contract begins October 1, 2027 and expires on September 30, 2044, however the IRP study does not account for a change of contract structure following the end of the POC contract term and assumes the POC contract structure continues through the end of the study period. At this time the structure of a new 2045 BPA contract would be hypothetical and is not considered.

BPA Tier 2

Under the current Regional Dialogue contract the PUD's load does not exceed its allocated contract amount of Tier 1 power. However, once the POC contract begins in 2028 the PUD will face above high water mark or "Tier 2" load. Tier 2 load service is for load above the Tier 1 contract allocation and is structured and priced differently to preference Tier 1 power. The PUD will need to make two choices in 2026 regarding which Tier 2 products to purchase (if any). The first choice will be the type of product(s), and the second is the associated volumes. Descriptions of Tier 2 products and their associated attributes are included in **SECTION 5 BPA TIER 2**.

Transmission

When the PUD changed to Load-Following for power delivery, the transmission portfolio also transitioned to better accommodate the new power product. The PUD became a Network

Transmission (NT) customer and converted a significant portion of its long-term point-to-point transmission contractual rights for NT use. The NT product substantially changes the planning environment for supply-side resources previously modeled in the IRP process. Network Transmission is a product that places the responsibility of serving network loads upon the transmission provider. The product incurs charges based on network usage during the peak network hour instead of a flat reservation cost for firm service. Because the cost of NT service is separated from the average amount of transmission usage, the IRP does not include transmission costs for new supply side resources unless they impact local load within the service territory.

Curtailments remain a risk for Network service. Load shedding events are extremely rare, meaning curtailment risks are primarily financial and regulatory through the loss of environmental attributes from curtailed generation. Tier 2 product provisions would similarly protect load service from impact in the case of curtailments. Network transmission costs are calculated in the IRP. While the costs can be mitigated with demand side resources, they are unaffected by other types of resources. These costs are included in the total portfolio costs.

In 2023 BPA launched an initiative in a special rate case process to reform its Standard Large Generation Interconnection Procedures (LGIP) to alleviate long interconnection queue delays. At the time of reform, the LGIP was a “first-come, first-served” serial process where studies were done as project information was available. In a serial process, changes to projects during system impact or facility studies on a project near the front of the queue would have adverse impacts on projects farther down the queue leading to restudy delays and costs. In the TC-25 effort BPA revised its methodology to use a “first-ready, first-served” “cluster study” format where a window would open to projects meeting certain readiness requirements and all projects would be studied simultaneously rather than sequentially. This change to the interconnection process is ongoing with the transition cluster study expected to open its application window in 2025 and the study itself to start in October 2025.

In February 2025 BPA paused its Transmission Service Request (TSR) Study and Expansion Project (TSEP) when TSRs reached 65GW of unstudied transmission requests and the backlog becoming unmanageable. Transmission expansion is a challenge in the current environment. New transmission builds are not keeping pace with increasing needs and BPA determined that a revised transmission study process was needed. At the time of writing neither the new process nor next TSEP cluster study have not been announced, and the transmission request pause remains in effect. Consideration of transmission constraints is critical to developing a holistic resource strategy and the 2027 IRP update will include updates as available.

Energy Policy and Regulatory Requirements

Future legislative policy and regulatory requirements can have profound effects on the PUD's power supply portfolio and the future resources it may consider, acquire, or operate. For example, the requirements of CETA will help shape the portfolio options and choices available to the PUD over the planning horizon. In addition, there are several ongoing regulatory processes that may have a significant impact on the PUD's existing resources or future resource decisions.

Tariffs and Supply Chain

In 2024 the federal government began implementing a series of tariff policies on imported raw materials and manufactured goods. Manufacturers and consumers began preparing for cost increases associated with new tariff policies on supply side resource builds. The tariff policies are evolving over time and have impacted new resource costs in the IRP. As tariff policies change, the IRP update in 2027 will incorporate more information on costs and manufactured goods availability.

The direct impacts of the Covid-19 pandemic have largely passed in 2025; however supply chain impacts are ongoing, and lead times have dramatically increased over the past 4 years. Supply chain challenges represent delays for new supply side resource options and increase the project timelines for new utility scale renewable generation projects. These delays, including extended renewable development timelines, supply chain challenges, and interconnection request backlogs represent some of the questions for the IRP to examine.

Inflation Reduction Act and Tax Policy

The 2022 Inflation Reduction Act (IRA) provided tax benefits on renewable energy projects and energy storage and allowed non-taxed entities to claim some capital tax benefits on such projects. These tax credits reduce the effective capital costs of projects depending on several factors up to 30%, however the IRP only assumes a 15% reduction in capital costs and used updated market pricing from a Renewable RFP to further adjust renewable project pricing to capture uncertainty associated with tariff policy and tax credit changes during the course of the 2025 IRP analysis. As tax credit policy evolves, the IRP update in 2027 will include any future changes.

WA State Bill 5445

Washington State Bill 5445 is a new law passed in 2025 that gives incentives to distributed energy priorities to encourage development. For the IRP, these changes are represented by changes to demand response, energy storage, and local solar projects. For energy storage projects located within the current utility infrastructure sites and demand response programs, the bill grants equivalent RECs compliant with the EIA requirements based on resource capability and total system load. For solar projects commissioned before Jan 1, 2030, and located on utility or superfund sites within a utility's service territory the existing multiplier on RECs is increased from 2 times to 4 times generation. These changes represent new opportunities for energy storage, demand response, and local solar.

WA State Bill 5974

In 2022, former Governor Inslee issued a directive for Washington State (along with Washington State Bill 5974) requiring "all publicly owned and privately owned passenger and light duty vehicles model year 2030 or later that are sold, purchased, or registered in Washington state be electric vehicles." The policy tracks and follows similar policies in California. This mandate increases expectations of electric vehicle adoption through the study period. The 2025 IRP utilizes the existing policy environment and accounts for increased electric vehicle adoption; any changes to legislation or policy will be reflected in subsequent IRPs and IRP updates.

Energy Independence Act

In 2006, the voters of Washington State approved the EIA through the state's initiative process. This Act requires electric utilities with 25,000 or more customers to pursue all cost-effective energy conservation measures, and to acquire and include in their portfolios a mandated amount of eligible renewable resources, renewable energy credits, or combination of the two. The amount of eligible renewable resources required scales based upon the utility's retail load.

Utilities have three methods to comply with the renewable mandate of the EIA: meeting the load-based goals with resources or RECs, demonstrating investment of 1% of its retail revenue requirement in eligible renewable resources or RECs without load growth, or demonstrating investment in excess of 4% of the utility's annual retail revenue requirement (commonly referred to as the "cost cap" method) in eligible renewable resources or RECs. The IRP assumes the PUD will comply via load-based goals given the load growth expectations.

Clean Energy Transformation Act

In 2019, the Washington State legislature passed CETA. CETA places several new requirements on utilities centered around clean energy targets beginning in 2030. The core clean energy CETA provisions require:

- Elimination of coal from rates by 2026
- Utilities to be 100% carbon-neutral by 2030

    - “Alternative compliance” available for up to 20% of a utility’s total retail load amount
- Utilities to be 100% carbon-free by 2045

Because the PUD relies on a portfolio that is predominantly carbon-free, the PUD anticipates full compliance with CETA’s clean energy provisions. The Clean Energy Transformation Act (CETA) contains several requirements which have been incorporated in the IRP.

In 2030 the PUD must be 100% net carbon neutral. The PUD plans to achieve this using its clean power portfolio and utilizing compliant renewable energy credits for those carbon emissions associated with BPA market operations, which may account for up to 20% of the PUD’s total retail load.

The carbon emissions from BPA’s system are the most significant source of carbon associated with the PUD’s portfolio. Because BPA engages in market transactions to balance their hour-to-hour resource and load obligations, those market transactions may carry some portion of carbon emissions which is attributed to BPA’s overall fuel mix. This fuel mix is assigned, pro rata, to each of BPA’s customers translating into a carbon obligation for the PUD. In order to comply with the 2030 standard, the PUD expects to procure either renewable energy resources to serve load or environmental attributes for alternative compliance to achieve a net zero power portfolio from 2030 onward. CETA allows hydroelectric and non-emitting resources to supply clean energy to serve load including nuclear energy and fusion energy.

The current policy environment in Washington State contains multiple clean energy regulations with distinct goals and metrics creating a challenge for utilities. Trying to comply with both CETA and EIA using a single integrated compliance strategy is difficult given the divergent constraints. To help provide insight into these challenges the IRP studied a scenario with a single environmental policy environment for resource planning to highlight potential inefficiencies in the multiple-compliance program framework.

Climate Commitment Act

Washington’s Climate Commitment Act (CCA) is a cap-and-invest style regulation that “caps” the total amount of emissions economy-wide. The program accomplishes this by requiring any carbon emissions to retire an associated “allowance” which are limited in number. The amount of allowed emissions is equal to the number of allowances issued. These allowances are primarily provided by the state via auction.

Electric utilities, however, primarily achieve their carbon reduction efforts through compliance with the Clean Energy Transformation Act (CETA). The CCA provides electric utilities a number of allowances at no cost allowing them to mitigate the costs of program. This protects utility ratepayers from double-paying for carbon reductions.

Because the CCA is designed to be cost-neutral for electric utilities, the IRP does not directly consider the CCA when building resource portfolios but rather focuses on regulatory compliance associated with the Energy Independence Act (EIA) and CETA. Staff will continue monitoring the CCA and how it develops to determine whether this approach may need to be updated in future IRP iterations.

The Electric Industry Regional Efforts

The electric industry in the Pacific Northwest is facing dynamic changes. When assessing the state of the industry, several anticipated developments relevant to utility resource planning stand out and must be considered when considering future actions. These include the regional Resource Adequacy Program, the NWPCC's Power Plan, and the potential for newly forming day ahead electricity markets.

Western Resource Adequacy Program

The Western Resource Adequacy Program (WRAP) represents a regional program from the Western Power Pool based on member requests and a regional acknowledgement that resource adequacy concerns are growing, and a standardized resource adequacy metric is needed. The PUD was involved in the development of the WRAP program and its associated tariff with a binding requirement by summer of 2027. The PUDs 2023 IRP included WRAP as a consideration, but WRAP requirements were incomplete at the time. As WRAP developed and the PUD considered its power supply portfolio, WRAP compliance appeared increasingly challenging. The PUD's change to the Load-Following shifts WRAP obligations to BPA, representing a reduction in financial risk for the PUD as BPA has more resources to meet WRAP obligations. The PUD is no longer a full member of WRAP but remains committed to regional success and seeks to continue developing WRAP.

Northwest Power and Conservation Council

The NWPCC is a public agency created by the Pacific Northwest Electric Power Planning and Conservation Act of 1980. The agency's three primary functions include:

1. Develop 20-year electric power plans for the Northwest that guarantee adequate and reliable energy at the lowest economic and environmental cost;
2. Develop programming to protect and rebuild fish and wildlife populations affected by hydropower development in the Columbia River Basin; and
3. Educate and involve the public in the Council's decision-making processes.

Due to the nature of the Council's work and its structure within the Northwest Power Act, its five-year power plan serves as a guidebook for resource planning in the region. Many utilities, as well as BPA, look to the Council's Power Plans as a key source of information for their own planning needs.

The Council's 2021 Power Plan covering 2022 through 2042 with an action plan from 2022 to 2027 is the current power plan with the ninth power plan in development. The current plan was developed at a time when the Northwest power system was facing increased renewable energy penetration, changes in clean energy policy changes, baseload resource retirements, salmon recovery actions, electrification, and the climate change impacts to load.

Key findings for the 2021 Power Plan analysis include:

1. Much of the inexpensive efficiency has been achieved, and what remains is close to the price of power from the least expensive generating resources.
2. Utilities should study demand response programs in the form of Time of Use Rates (TOU) and Demand Voltage Reduction (DVR).
3. Renewable energy resources represent the lowest cost resource for meeting energy needs and clean energy requirements.
4. Energy imports from California in the form of renewable energy are important for the region. Thermal resources will be important in the power supply as the clean energy transition occurs slowly over time.
5. Regional collaboration on new market tools such as capacity or reserves products increase efficiency and reduce costs.

Energy Markets

Since 2015, several Northwest utilities either joined or signaled their intention to join the Energy Imbalance Market (EIM) is operated by the California Independent System Operator (CAISO). While the Northwest energy market has traditionally traded bilaterally on an hourly basis, the EIM is designed to balance energy and capacity needs through market dispatch on a sub-hourly basis. The region is monitoring the results and the cost/risk tradeoffs associated with joining an EIM, particularly as to how it can help contribute flexibility and value to the region.

Two day-ahead market options are in development across the western footprint representing new opportunities for the PUD: the Extended Day Ahead Market (EDAM) and Markets+. CAISO is working on the Extended Day Ahead Market (EDAM) to expand the footprint outside of California, while Markets+ is an offering from the Southwest Power Pool (SPP) representing a new market from the same administrators of the WRAP program. As a Load-Following customer, the PUD is not a market facing entity. However, the PUD will have a market presence vicariously through BPA. BPA issued a record of decision in 2025 opting to continue development of Markets+ and committing to join once the market is operational. When BPA joins Markets+ remaining in the EIM appears to be infeasible potentially leading to BPA, and by extension the PUD, exiting the EIM.

Day ahead markets will change how resources are dispatched and energy is traded across the Western interconnection. The PUD considers new markets as an opportunity for resource optimization to serve load. At this point it is unknown if or how resources owned by entities that are not market participants themselves can participate. As Markets+ continues development in its phase 2 the PUD will continue to advocate for hydro resources and BPA in the framework and update its planning models depending on further developments.

4 Scenarios and Planning Assumptions

Introduction

The 2025 IRP uses scenarios and sensitivities to test various environments by changing one or more key variables to compare resource plans. These different environments provide insights into how resource decisions change with varying input. Within each scenario or sensitivity, the opportunities and risks can be evaluated and the stability of resource plans across multiple environments gives insight into the best pathways. Maintaining flexibility in resource decisions to adapt to changing conditions helps to maintain least-cost, least-risk pathways for reducing costs to Snohomish PUD customers. The 2025 IRP examined 5 scenarios and 4 sensitivities.

Scenario Development

The scoping phase of the 2025 IRP provided critical insight from customers and subject matter experts regarding different scenarios and sensitivities in which to develop the IRP's portfolios, well beyond future load growth or future market energy price assumptions. These scenarios and sensitivities are born from questions such as:

- What if our service territory electrifies much faster over time than we think?
- What if technology advancements happen in a shorter timeframe than anticipated?
- What if the regional transmission system is constrained and new resources cannot be procured for load service?
- What if BPA costs change?
- What if the implementation rate of smart, grid integrated technology is faster than we think?
- What cost impacts would adding additional energy storage have?

Scenarios

Scenarios help explain how changes in economic, social, technical and environmental trends could affect the PUD's future load growth and resource forecast, and the cost and risk of various resource plans developed in response. These scenarios also provide useful insights into potential uncertainties and broad sets of risks the PUD could face under each of these futures. The 2025 IRP evaluated five scenarios that considered the range of futures the PUD could face for the 2026 through 2045 study period. The primary descriptors for each case are summarized below. All scenarios and sensitivities include climate change impacts, electrification growth, carbon pricing as per CETA, baseline organic rooftop solar installations and base conservation efforts.

1. Base Case Scenario
2. Low Growth Scenario
3. High Growth Scenario
4. High Technology Scenario
5. Limited Regional Renewables Scenario

Base Case Scenario

The future under the Base Case reflects moderate relative load growth due to expected economic growth and conditions. Market energy price forecasts take into account the progressively decarbonizing WECC region due to legislation such as Washington State's Clean Energy Transformation Act and various other regulatory and legislative mandates set by other states throughout the Western Interconnection. Resources across the Western Interconnection develop in line with current interconnection procedures.

Low Growth Scenario

The Low Growth Scenario reflects a future where economic growth and conditions are significantly less than average throughout our service territory and the greater WECC region. This could be caused by a variety of global or nationwide political, economic, and supply chain related causes. A low growth scenario also assumes cheaper market energy due to lower overall regional demand as well as a larger WECC-wide assumption in natural gas capacity. In the low growth scenario regional economic conditions result in lower energy prices, lower demand for energy projects and lower electric vehicle adoption.

High Growth Scenario

The High Growth Scenario is marked by higher relative average annual load growth for our service territory of Snohomish County and Camano Island. The socio-economic factors of population, employment, and income growth for the Puget Sound exceed the national average across the study period. The County's leadership in technology and innovation enhances its position in the global economy. The increased cost of housing in the greater Seattle area spurs residential development to more affordable Snohomish County. The advancement and application of innovative new technologies makes Puget Sound a hotbed for high tech industry, and South Snohomish County booms with new businesses and residents. New commercial and industrial development in North Snohomish County currently under construction finishes and comes to fruition causing a boom in economic development and with it energy and power capacity needs to supply that development. Load growth, resource costs and wholesale market energy costs are high, which makes this scenario prove comparatively challenging.

High Technology Scenario

The High Technology Scenario is a future where installed energy storage capacity throughout the WECC is exceptionally high, well beyond current and expected levels. The wholesale electricity market reflects a potential future where market participants buy energy in bulk during high renewable generation hours and dispatch that energy into peak hours however load is increased so prices stabilize at the base case level.

The High Technology scenario assumes novel or developing carbon free generation technologies become commercially available earlier at the same cost as they would in the base case. This includes earlier adoption of advanced nuclear technology such as small modular reactors, enhanced geothermal projects and fusion energy in the study period, at larger scales than in the base case. Other resources are available at lower cost than in the base case representing technological development of existing technology. The scale of resource availability is increased representing larger scales of project developments.

In the High Technology Scenario customer technology develops and is adopted at higher levels than the base case. In this scenario load is higher as more sectors of the Snohomish County and Camano Island economy electrify and electric vehicle adoption rates increase.

The High Technology scenario represents a more speculative future than the base case, high or low scenarios. Predicting the growth or development of new technologies is less predictable than economic indicators in the near term so this scenario is less predictive of resource decisions. However, this scenario does give valuable insight into the impacts of increased technological development on the resource decisions of the PUD and how resource plans could change to adapt.

Limited Renewable Project Availability

The Limited Renewable scenario envisions a WECC buildout where bulk transmission constraints, federal tariff policy, tax credit impacts, supply chain difficulties, or interconnection queue delays result in delayed and limited renewable energy projects being developed. In this scenario physical resources are limited leading to changes in regulatory compliance strategies. Due to limited physical resources being interconnected market prices are higher as supply is constrained, BPA Tier 2 costs are increased due to market price increases and less physical inventory is included in the long-term Tier 2 product. As fewer renewable projects attain operational status the market for environmental attributes is comparatively shallow leading to increased REC prices for similar demand.

Sensitivities

Sensitivities are single or limited variable changes to help understand how changes to a single variable impact resource decisions within the base case. The base case assumptions of carbon pricing, load, electrification, climate change, baseline rooftop solar and conservation efforts. Testing single or limited variable sensitivities grant insights to risks faced by the PUD and mitigation strategies for possible changes in the future. The 2025 IRP examined 4 sensitivities within the base case.

1. High BPA Costs
2. Low BPA Costs
3. Shallow Renewable Energy Credit Market
4. CETA Only Policy Environment

High BPA Costs

The PUD has historically gotten a majority of its bulk power from BPA however with the change to the Load-Following product the proportion of the PUD's power coming from BPA is expected to increase. Increased BPA costs for both preference or Tier 1 power and above-high-water mark or Tier 2 power are impactful to the PUD and may result in a different set of resource decisions. Load, market prices, resource costs and REC prices are the same as the base case while this sensitivity examines higher BPA Tier 1 costs, higher short and long-term Tier 2 costs and more physical resources in the long-term Tier 2 mix.

Low BPA Costs

In contrast to the High BPA Cost sensitivity the Low BPA cost sensitivity examines the impacts to resource decisions if BPA costs are lower than expected. Tier 1, short and long-term Tier 2 prices are lower in this variation of the base case while the long-term Tier 2 mix has fewer physical resources assuming fewer physical resource purchases. All other base case variables remain the same as above.

Shallow Renewable Energy Credit Market

The PUD's primary compliance approach to EIA RPS and CETA is to use a combination of bundled (RECs purchased with accompanying energy) and unbundled RECs (RECs purchased without accompanying energy). The PUD transacts in the bilateral market for unbundled RECs to help cost-effectively meet its compliance requirements. This sensitivity will assess the portfolio response to a shallow unbundled REC market depth that limits the supply for transactions, driving prices higher due to low supply while maintaining the same regional demand.

CETA Only Policy Environment

In 2030, both RPS and CETA will overlap, creating both clean energy and renewable energy requirements that are somewhat different. This sensitivity evaluates what a portfolio solution if CETA became the State's singular clean energy policy. If CETA becomes the single clean energy policy the Base Case variables remain the same except REC market depth will increase and REC prices will decrease.

Figure 4-1 IRP Scenario and Sensitivity Variable

Scenario	Load Forecast	BPA Costs	REC Price	Notes
Base	Base	Base	Base	
Low	Low	Low	Low	
High	High	High	High	
High Technology	High	Base	Low	Additional Supply Side Resource Options
Limited Renewable	Base	High	High	Later Supply Side Resources at Limited Scale
High BPA Costs	Base	High	Base	
Low BPA Costs	Base	Low	Base	
Shallow REC Market	Base	Base	High	
CETA Only Policy Environment	Base	Base	Low	

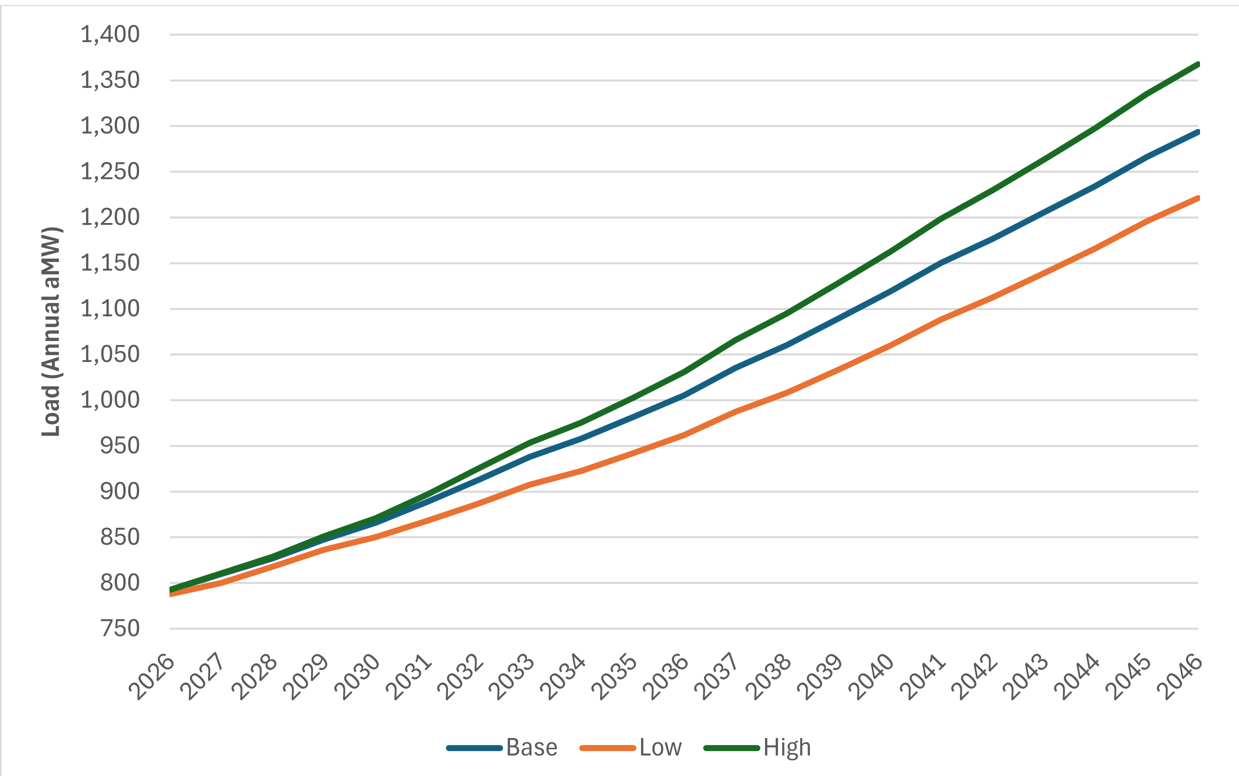
Load Forecasts

The range of load forecasts developed for the 2025 IRP rely on a mix of econometric and deterministic approaches. An econometric approach was used for modeling historical weather, consumption, and customer information to build a baseline from which future years can be predicted. In building this baseline, the PUD relies on actual consumption data from the past several years by sector and then, holding other variables constant, forecasts what consumption would have been under normal or expected historical weather.

With the baseline established, PUD staff then adjusted for expected future conditions, including changes in: population, housing type and efficiency, electric vehicle adoption[9], electric water and space heating adoption, county employment and projections in the goods-producing, service-producing and military sectors, known industrial developments, and other factors. These changes are summed and net effects are applied over the forecast period.

Figure 4-2 shows the average annual load forecast by scenario for the 2026 through 2045 study period, before new conservation. Note that the Limited Renewable Project shares the same load forecast as the Base Case Scenario and are not shown in Figure 4-2.

Figure 4-2 Average Annual Load Growth Trajectories Before New Demand-side Resources



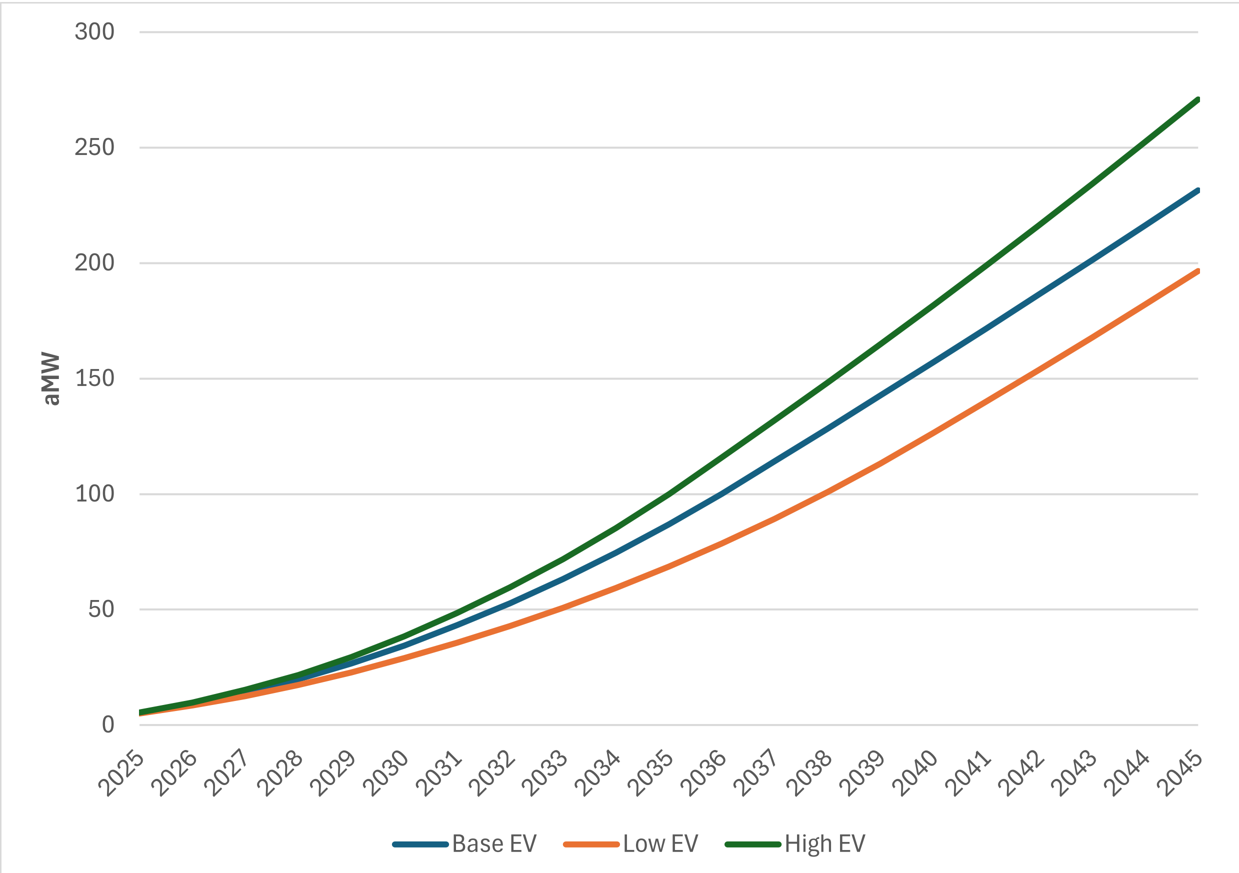
Electric Vehicle Adoption

Electric vehicle (EV) adoption assumptions were built into each of the scenario load forecasts and reflect the PUD's expectation that EV's may become a significant component of future load growth. State policy mandates more electric vehicle adoption and a phase-out of internal combustion engine vehicles leading to increasing EV adoption over all scenarios.

[9] Estimates for electric vehicle adoption (plug-in electric and battery electric technologies) in the PUD's service territory were derived from a 2017 joint study performed Energy and Environmental Economics (E3), *"Economic & Grid Impacts of Plug-In Electric Vehicle Adoption in Washington & Oregon,"* March 2017. This study was

In the High-Technology scenario EV growth is accelerated to account for EV technology developing faster and the infrastructure required for EV adoption to come earlier. The High Growth Scenario uses the same EV growth rate as the High-Technology scenario. The Low Growth Scenario uses a low EV adoption rate. All other scenarios and sensitivities use the Base level of EV growth. Figure 4-3 illustrates the adoption rates used in the Low Growth case, Base case, and High Growth case.

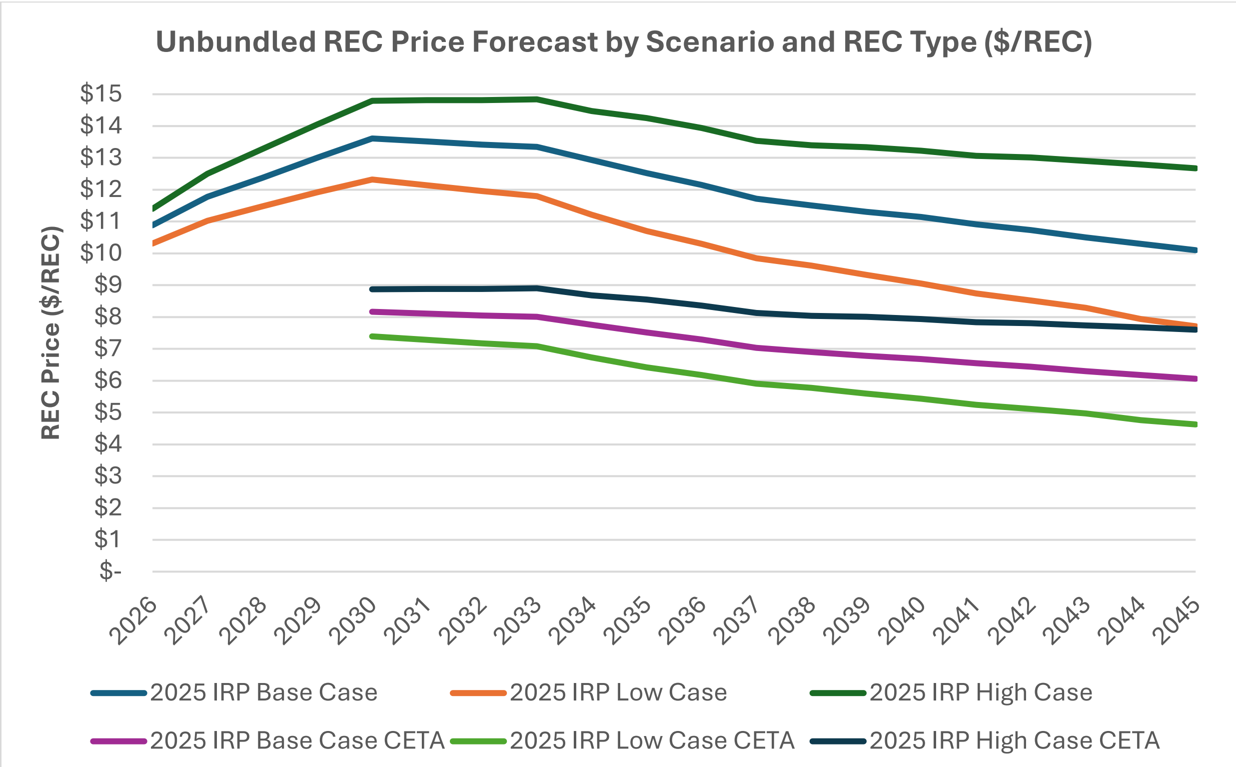
Figure 4-3 Electrical Vehicle Adoption Rate Assumptions (aMW)



REC Price Forecast

The 2025 IRP uses three price forecasts for EIA compliant RECs and three price forecasts for CETA compliant RECs used for alternative compliance options. The 100% net clean with maximum 20% alternative compliance portion of CETA begins in 2030, before that period CETA RECs are not shown with any price. In the 2026 to 2030 compliance period EIA compliant RECs continue to increase in price as regional loads and needs grow and resource connection delays limit new supply leading to increasing prices. In 2030 CETA becomes a constraint and the REC supply from hydro resources gain regulatory compliance attributes price is expected to be lower than EIA compliant RECs and prices decrease over time as the regional buildout of renewable resources increases REC supply.

Figure 4-4 Unbundled REC Price Forecast by REC Type ($/REC)



Planning Assumptions

BPA Long-Term Contract

In 2024 the PUD asked to change its BPA long-term power product from the Block-Slice Product to the Load-Following Product following a comprehensive analysis of potential "what-ifs" on past performance, a short-term look-ahead analysis, a long-term analysis and a qualitative analysis. The conclusion of these studies was the Load-Following Product provided better load service options with more cost stability for PUD customers. The PUD selected the Load-Following Product in the Provider of Choice Contract starting 2028 through 2045.

The **Load-Following** product provides firm power service to meet customer load minus dedicated resources, with BPA assuming load service planning responsibility for peak loads. This product is scheduled by BPA to serve load but requires separate service with additional cost to integrate renewable resources. The costs of the Load-Following Product fall into three categories: fixed structural costs, energy costs, and peak demand costs. Above contract high water mark load allocation may be served with Tier 2, non-federal resources, or a combination of both.

The **Block and Block with Shaping Capacity** products provide a planned amount of firm power to meet planned annual net load. The block product gives a set amount of power in each hour in either a flat annual block shape or a block shaped to the forecast load minus resources. When shaped, the block can vary between heavy and light load hours and by month. The PUD does not have sufficient owned or contracted resources to be a BPA Block customer without a significant cost impact.

The **Block/Slice** product is a composite of two distinct power products. The block portion is similar to the standalone Block product, with monthly energy volumes determined by load. All hourly deliveries are equal throughout the month, though each month's volume is different. Block amounts are calculated as the difference between the annual net requirements load and the firm slice amount. The Slice portion of the power product represents a federal system sale including firm requirements power, hourly scheduling, and environmental attributes but not operational control. The ability to ramp the Slice portion of the Block/Slice product was a key feature to integrate new renewable energy projects without the additional Resource Support Service costs. This was the BPA product the PUD held until October 1, 2025 when the formal switch to Load-Following occurred.

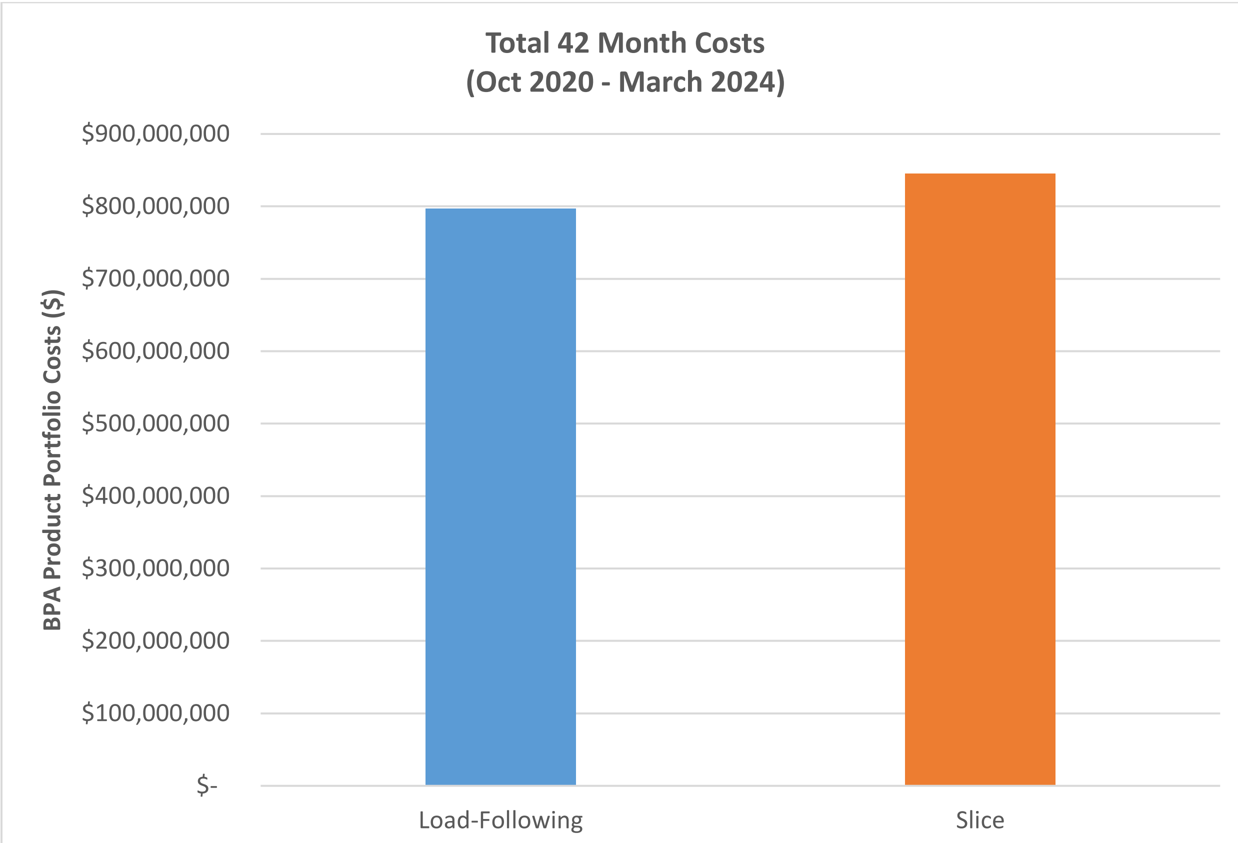
BPA Product Switch

In early 2024, the PUD requested an opportunity to examine the possibility of changing to the Load-Following product from BPA within the scope of the current Regional Dialogue contract. PUD staff conducted four different studies looking at various aspects of a potential Load-Following switch.

Look-Back Analysis

The Look-Back analysis examined how the PUD would have fared if it had been Load-Following in the prior three years. This period included 3 extreme weather events, one summer heat dome event and two regional cold events. The results of this analysis concluded the PUD would have benefited from access to BPA Load-Following capacity.

Figure 4-5 Look-Back Analysis Cost Results Oct 2020 - March 2024



The results of the Look-Back analysis indicated the PUD would have saved $48 million under the Load-Following product compared to what occurred assuming the same load conditions, market purchases or sales, BPA rates and power bills.

Look-Forward Analysis

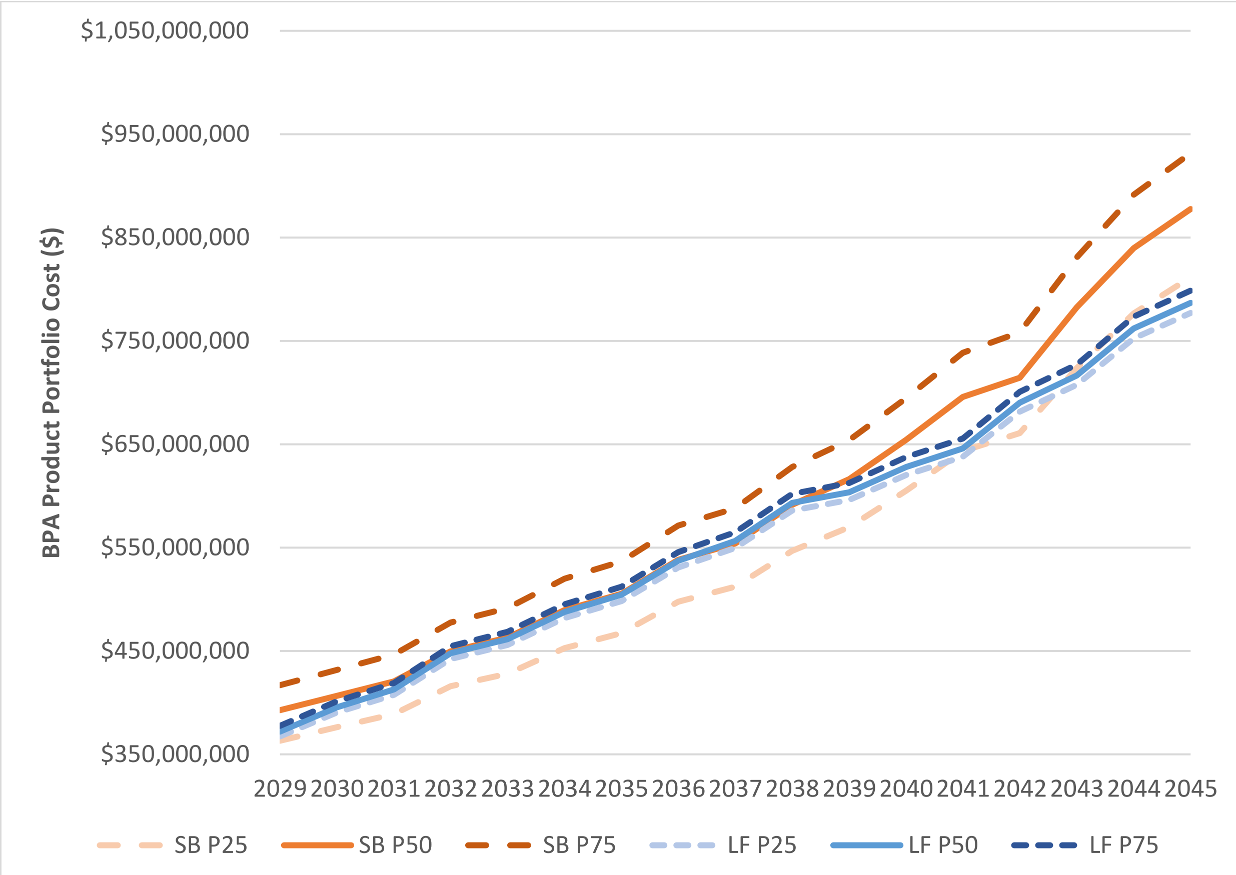
The Look-Forward analysis explored the planned future for fiscal year 2026 through fiscal year 2028 which aligns closely with the end of the current BPA contract in 2028. The Look-Forward study is a probabilistic analysis of both products under a wide range of hydro and load conditions across weather conditions. Upcoming requirements for the Western Resource Adequacy Program (WRAP) and organized market costs were included in the analysis. The PUD's transmission portfolio transition costs and resource integration costs were assumed for Load-Following. Comparing costs on an equal footing between the products in the expected operating environment showed Load-Following savings of $13 million over Block/Slice at expected conditions. Variability was higher under Block/Slice and structural costs related to WRAP compliance shifted in 2027.

Figure 4-6 Look-Forward Analysis Results FY26 - FY28

Long-Term Analysis

The Long-Term analysis studied the cost impacts from 2029 through 2045, incorporating the impacts of WRAP, Slice moving from an hourly product to a day-ahead product in organized markets. WRAP costs are significant in the early term for Block/Slice while resource builds offset WRAP costs while load service needs eventually result in sufficient procurements to eliminate WRAP compliance costs. Environmental compliance was a revenue opportunity in the post 2030 CETA environment with excess hydro production in expected scenarios generating more RECs than required for regulatory needs. Load-Following does not carry WRAP compliance costs and BPA Tier 2 provided for load service in the long-term study, however regulatory compliance costs are higher with Load-Following. The results of the study showed the total net present value costs of Block/Slice were $170 million more than Load-Following at expected conditions.

Figure 4-7 Long-Term Analysis Portfolio Costs 2029 - 2045



The Qualitative Study examined impacts that were not captured in the previous studies but were worth consideration. PUD staff were surveyed and 50 topics across 6 subject areas were identified. The areas of concern identified were financial systems, strategic plan alignment, resource diversity, future needs, market depth, and organizational impacts.

High level results of the qualitative study showed the PUD could meet its strategic goals with less complexity and risk with Load-Following than with Block/Slice. Changing to Load-Following will come with trade-offs for resource flexibility, local operational control, and resource diversity. Load-Following had small positive forecast impacts for the PUD's financial systems via less variance and increased credit rating. Both products aligned with the PUD's strategic plan and both have pathways forward to meet the strategic objectives. Resource diversity is expected to decrease with Load-Following meaning Block/Slice had an advantage in staff's opinion. Future needs identified WRAP compliance requirements, markets risks and regulatory compliance flexibility as requirements each product would need to satisfy. Load-Following had met future needs with less risk and complexity and was clearly superior in this aspect. Load-Following reduces market exposure in an increasingly thin wholesale energy market, making Load-Following less risky. Organizational impacts were expected for PUD departments working the Block/Slice product and real time power marketing. Staff level changes were expected under Load-Following, but exact impacts were unknown.

The results of the four product studies showed a net benefit to the PUD to switch to the Load-Following product. Staff recommended making a formal request to change the PUD's BPA power product and the commission agreed with staff assessments. The final product change occurred on October 1, 2025.

After the product change was confirmed with BPA and implementation began, the PUD determined that NT costs were lower than PTP, resulting in net savings. In addition, Resource Support Services (RSS) provided a net benefit for the Jackson Hydroelectric Project. Together, these factors reduced the overall cost of Load-Following compared to what had been projected during the product switch analysis.

BPA Tier 1 Allocation

Until October 2028 under the existing contract for ratemaking purposes, BPA determines the total of its customers' loads and the Federal System size to allocate costs over the two-year rate period[10]. This Rate Period High Water Mark process establishes the maximum amount of energy the PUD is eligible to purchase from the BPA at cost, or the Tier 1 rate. Under the current contract term beginning in October 2011, the size of the Tier 1 System has varied. Tier 1 System size variations occur due to changes in BPA's system obligations and hydro operations, and maintenance outages and refurbishments to the federal hydro system. Table 4-1 shows the actual BPA Tier 1 System Size and Tier 1 contract allocation to the PUD from 2015 through 2025.[11]

Table 4-1 BPA Tier 1 System Size and Snohomish PUD Tier 1 Allocation

Fiscal Year	BPA Tier 1 System Size (in aMW)	Maximum Tier 1 Available to PUD Rate Period High Water Mark (in aMW)	Actual BPA Tier 1 Contract Allocation to Snohomish PUD (in aMW)
2015	6992	811	755
2016	6983	791	759
2017	6983	791	778
2018	6945	786	729
2019	6945	786	729

[10] The 2026 Rate Period is 3 years by agreement to accommodate the new BPA contract negotiations
[11] BPA Tier 1 is allocated contractually based on the customer's Tier 1 Cost Allocation (TOCA) percentage.

2020	6985	795	726
2021	6995	795	726
2022	6802	762	718
2023	6670	762	720
2024	7098	799	756
2025	7028	799	771

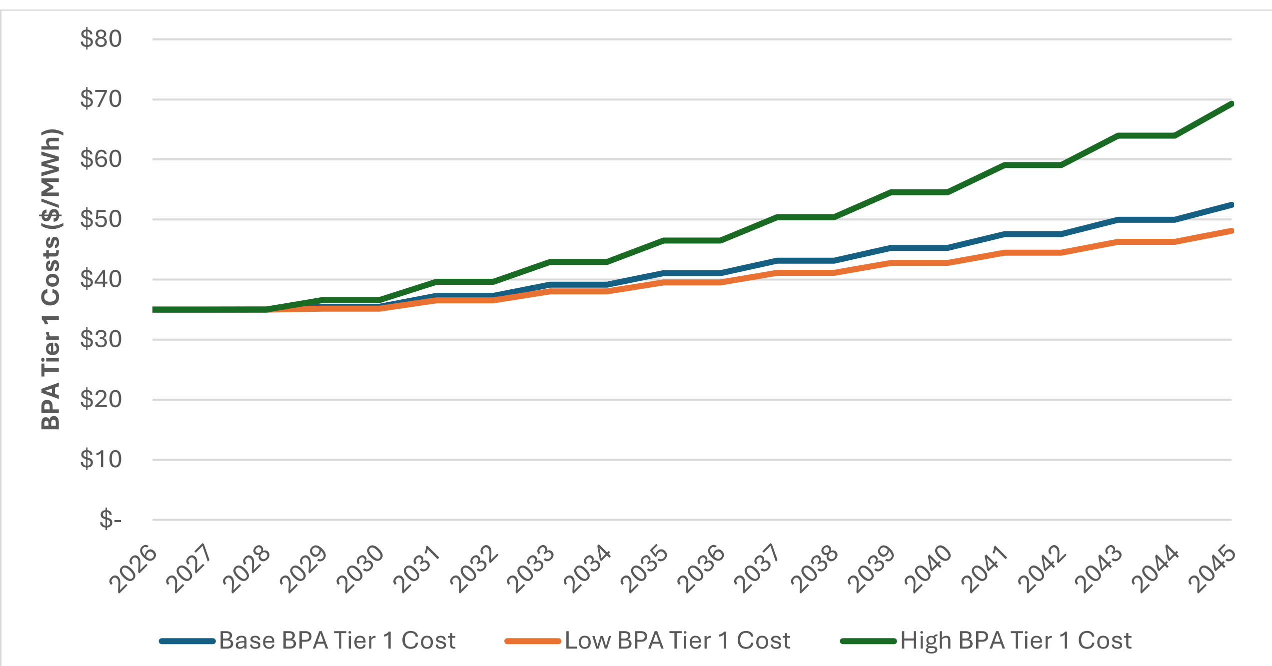
On October 1, 2028, under the new POC contract the BPA Tier 1 system size will be fixed at 7250 aMW granting a stable planning baseline for Tier 1 allocation.

With the change in BPA products the PUD will continue purchasing the Load-Following product for at least 2 rate periods following the start of the 2028 contract with an option to change products one time included in the contract provisions.

BPA Costs

The PUD's power portfolio is predominantly BPA Tier 1 energy; hence the PUD's power costs are correlated with BPA Tier 1 costs. One key variable for the assorted scenarios and sensitivities is BPA cost trajectories. Three forecasts were created to be used for low, base and high BPA cost environments. The chart below shows the costs across forecasts on a rate case basis for Tier 1 service based on the PUD's net requirements and the BPA energy charges

Figure 4-8 BPA Tier 1 Costs ($/MWh)



The base cost trajectory is used in the Base, High Technology, Limited Renewable Project, Shallow REC Market and CETA Only Policy scenarios or sensitivities. The low-cost forecast is used for the Low Growth and Low BPA Cost scenarios while the high-cost trajectory is used in the High Growth and High BPA Cost scenarios. These three cost trajectories give insights into PUD cost exposure and resource decisions based on BPA cost changes.

Carbon Costs

In IRPs prior to 2021 the cost of carbon was included in all scenarios ranging between 13 and 90 dollars per metric ton of carbon dioxide equivalent, depending on the scenario and year. After 2021, as per CETA, IRPs must include the price of carbon as defined by law. While the PUD has no plans to own or operate carbon emitting generation sources, any energy purchased from the wholesale market, including in BPA's fuel mix, will have some amount of carbon, as other market participants market may generate and/or sell electricity produced by carbon emitting sources.

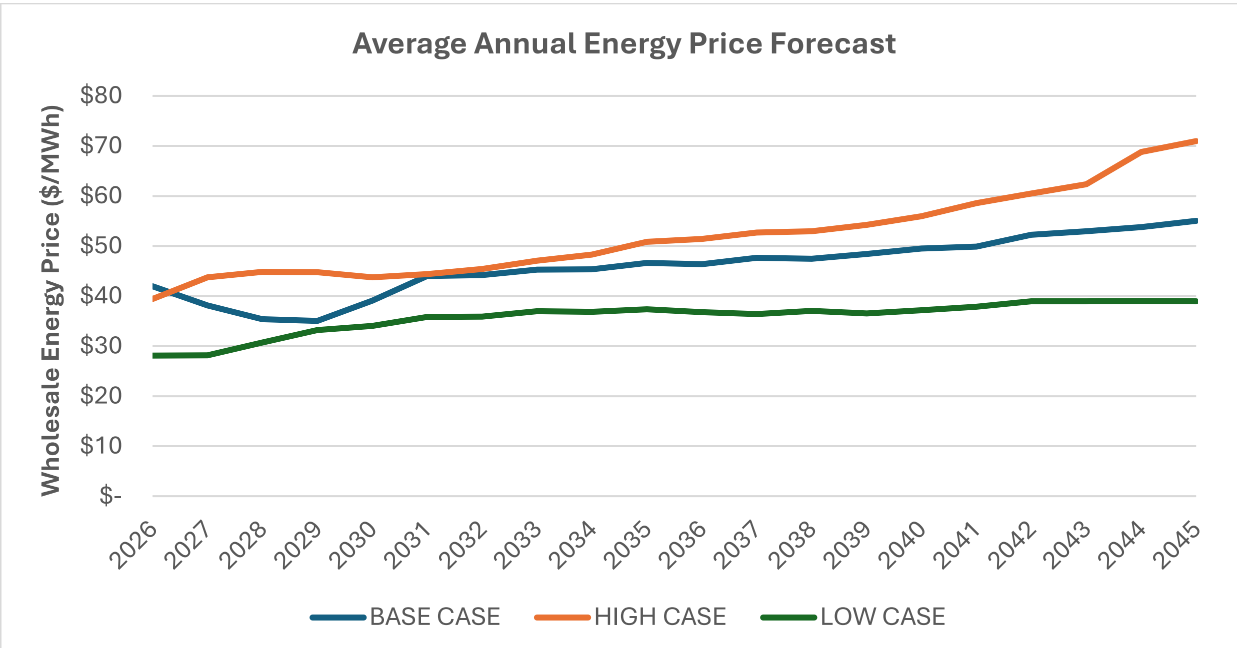
Table 4-2 Carbon Price ($/MWh)

Year	Carbon Price ($/MWh)
2026	$83.29
2027	$86.63
2028	$90.12
2029	$93.66
2030	$97.42
2031	$101.17
2032	$106.71
2033	$110.79
2034	$113.94
2035	$117.91
2036	$121.16
2037	$124.45
2038	$128.60
2039	$131.99
2040	$136.26
2041	$139.75
2042	$144.15
2043	$148.61
2044	$155.05
2045	$159.67

Forecast Wholesale Market Energy Prices

The PUD does not use a capacity expansion model to generate its own price forecasts. Instead peer utilities and organizations with market price forecasts are used if they have the societal cost of carbon included. The final market price forecast is a blend of forecasts from Puget Sound Energy, Avista Utilities, Seattle City Light, and the NWPCC. Using peer utilities gives a wider range of expectations with varying expected resource builds and hence price threads. A blended price thread is then expanded to create a high and low-price expectation. These market prices inform BPA Tier 2 prices and reflect expectations of fundamental energy prices.

Figure 4-9 Wholesale Market Price Forecast



5 Analytical Framework

This section of the 2025 IRP document discusses the quantitative analytical framework within the 2025 IRP. This framework includes input variables like load, resource option costs, resource output profiles and regulatory compliance attributes. The framework also includes discussion of the structure of the optimization model that uses IRP inputs to calculate the cost of the portfolio, with the goal of identifying the lowest reasonable cost portfolio for each scenario.

Scenarios, load forecasts, existing resource forecasts, and other key planning assumptions are described in Section 4 and provide additional insights on load forecast input variables. Section 6 discusses the outputs of the analytical framework: the resulting candidate case portfolios and the Long-Term Resource Strategy formed by consideration of those portfolios.

Optimization Framework

The goal of the 2025 IRP analysis, consistent with the statutory requirements in RCW 19.280.030, is to integrate into a long-range assessment the lowest reasonable cost mix of supply and demand side resources that meet current and future needs under a range of scenarios or futures. To perform this analysis, the PUD used an integrated portfolio approach, established parameters based on BPA billing and Washington State regulatory compliance requirements, selected resources from the demand and supply-side resource options, and developed candidate portfolios for each case scenario.

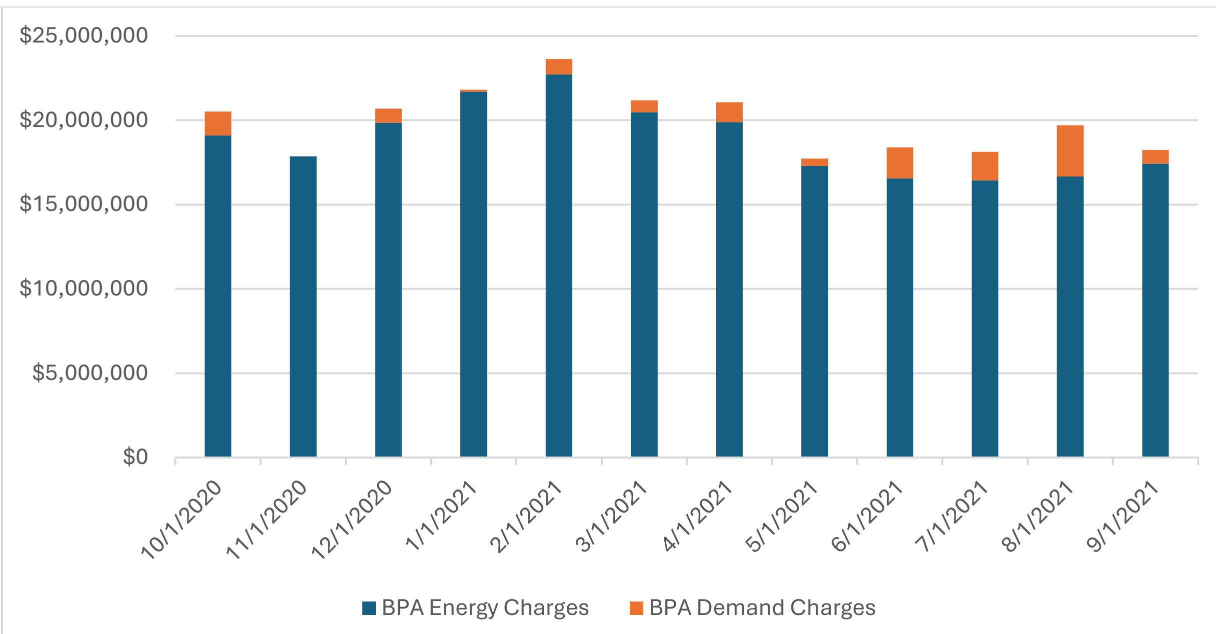
An in-house portfolio optimization model was developed to solve for the lowest reasonable cost portfolio, that satisfied regulatory compliance requirements and constraints, for each case scenario. This in-house model calculated millions of possible combinations of supply-side resources, conservation by cost bundle, BPA Tier 2 product options, demand response and rates programs, and unbundled RECs, and solved for the optimal combination of demand and supply-side resources, resulting in the lowest reasonable cost, identified as the net present value (NPV) of net portfolio costs for the scenario. **SECTION 6 PORTFOLIO RESULTS** provides additional detail on the new resource additions for each portfolio in the 2025 IRP analysis.

Solving Energy Needs

A significant effort in the integrated resource planning process is for the utility to assess how it can meet its customers' future needs with its existing energy resources, and when it will need to plan for new resource additions. Serving customer loads requires energy and capacity resources from a utility's power portfolio. In a power portfolio, energy resources provide power over extended periods of time, such as months or years. Examples include solar, wind, hydropower, and geothermal resources. This contrasts with capacity resources which are best suited to provide power or load relief on a targeted, time-limited basis.

The PUD is a Load-Following customer of BPA and as such, it receives energy and capacity through that product. The Load-Following product provides the PUD with a block of energy that is priced based on a forecast of annual energy consumption and monthly actual consumption, as well as capacity that ramps up and down with load and is priced based on the monthly peak hour load of the PUD. Most of the cost of the PUD Load-Following bill is from energy charges, and the balance is from capacity charges (called "Demand Charges" by BPA). As an example, the following is a monthly and annual breakdown of what PUD Load-Following charges would have been in FY2021 based on actual BPA rates and actual PUD loads.

Figure 5-1 FY2021 BPA Load-Following Bill Categorization Example



Under the BPA Load-Following product contract, BPA is obligated to serve up to 100% of the PUD's total retail load through tiered rate structures. Tier 1 energy is priced at the cost to produce energy from the federal system and is considered low-cost energy due to its average price. For example, the forecast average BPA Power cost in the PUD's 2026 budget is $37.40/MWh compared to the EIA's Northwest wholesale power price forecast for 2025 of $55/MWh[12]. Utilities can access Tier 1 energy up to a contractual ceiling called a High-Water-

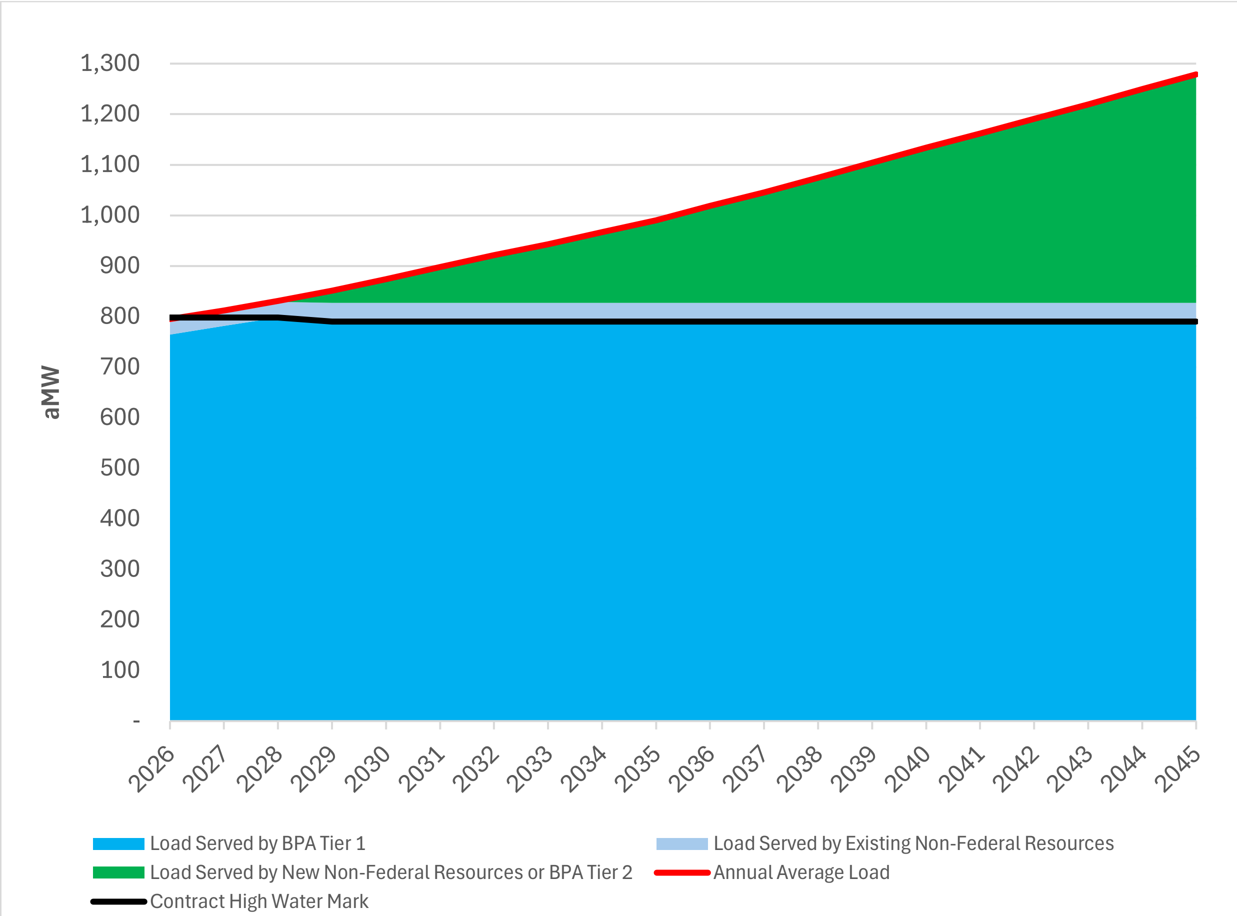
[12] Energy Information Administration. January 27, 2025. Forecast wholesale power prices and retail electricity prices rise modestly in 2025. https://www.eia.gov/todayinenergy/detail.php?id=64384#:~:text=We%20forecast%20that%20the%2011%20wholesale%20prices%20we,2025%20%28weighted%20by%20demand%29%2C%20up%207%25%20from%202024.

Mark. Load that exceeds the contractual ceiling is referred to as Above-High-Water-Mark (AHWM) load. AHWM load can be served by BPA Tier 2 energy, or through resources the utility acquires, referred to by BPA as “non-federal resources”.

Starting in 2029, the PUD is forecast to have a total retail load higher than its Tier 1 energy allotment (AHWM load). The figure below shows the PUD’s Above-Contract-High-Watermark load in the Base Case scenario. AHWM loads start at 7 aMW in 2029, increases to 96 aMW by 2035, and are forecast to reach 316 aMW by 2045. A fundamental question of the 2025 IRP is what resource options to serve this AHWM load result in the lowest costs for PUD customers. The answer must consider the cost of the resources as well as how the resources do or do not contribute to overlapping regulatory compliance needs. The Portfolio Optimization tool assesses all available resources and optimizes the portfolio for all needs simultaneously.

Figure 5-2 below shows an example of BPA’s Contract High Water Mark when applied the PUD’s load forecast for the Base Case scenario. The red line represents the annual average load forecast. The black line represents the Contract High Water Mark, where any shaded area above that black line and up to the red line must be served with energy that is not BPA Tier 1 energy. This energy would be from existing or future demand-side or supply-side resources, or from BPA Tier 2.

Figure 5-2 Contract High-Water-Mark and Forecast Load

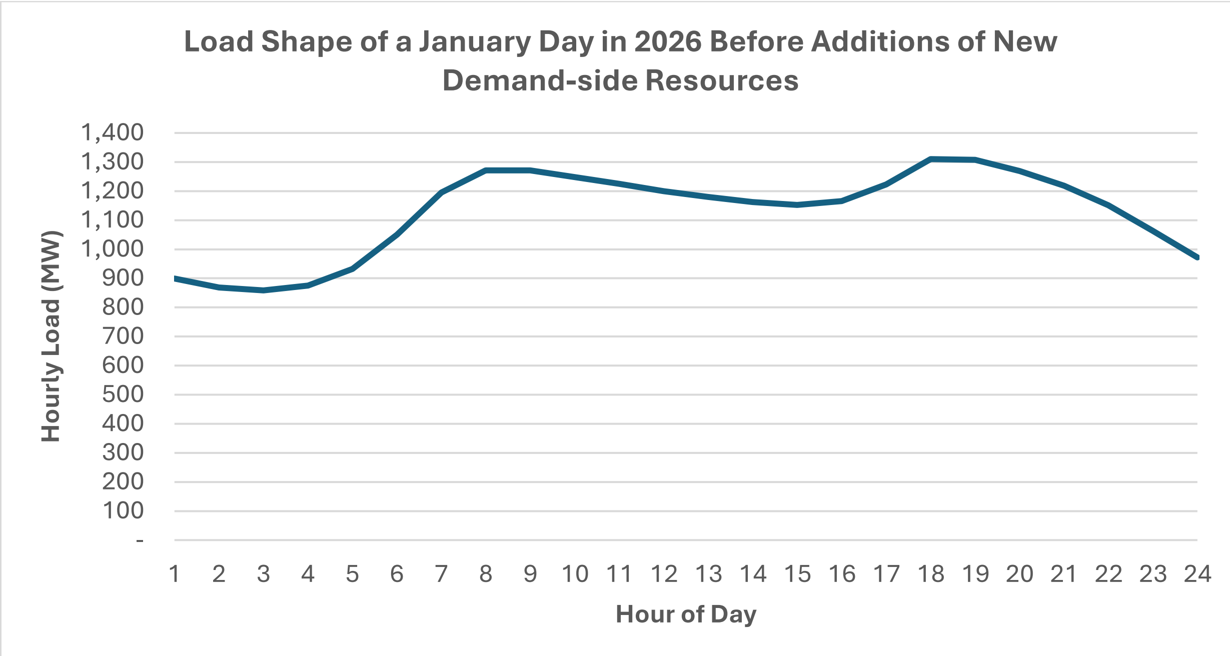


BPA Tier 2 energy is offered in two main product forms in the Post-2028 BPA Power contract: Short-term Tier 2 and Long-term Tier 2. The characteristics of Tier 2 products are described in **SECTION 5 BPA TIER 2.** Non-federal resources are demand-side or supply-side resources procured by the PUD for purposes of reducing load, serving load, and/or meeting regulatory compliance obligations. Any Above-Contract-High-Watermark load servicing needs not displaced by new non-federal resources would be served by BPA Tier 2.

Solving Capacity Costs

Under the BPA Load-Following product, the PUD has access to BPA capacity to serve load variations that occur on an hourly basis. The typical load profile of the PUD's total retail load varies across the day based on the consumption of PUD retail customers. This load profile, illustrated in the figure below, is typically characterized by a morning peak and an evening peak with a base level of energy consumption throughout the day and overnight. The Load-Following product ramps up and down to meet local demand.

Figure 5-3 Hourly Load Shape Jan 2026



Capacity pricing under the Load-Following product is based on the highest hourly load for a given month, and the rate design (or billing equation) is different in FY2026-2028 period from the FY2029-FY2045 period. This is due to the differing rate designs in the BPA Regional Dialogue contract which expires in FY2028, and the new BPA POC contract which starts in FY2029. In the Regional Dialogue contract capacity pricing (called the Demand Charge) is given by the following equation:

Figure 5-4 RD Demand Charge Calculation

$$\begin{aligned} &\mathit{Monthly\ Demand\ Charge} \\ &\qquad = \mathit{Monthly\ Capacity\ Price} * (\mathit{Peak\ Hour\ Load} - \mathit{HLH\ Load\ in\ aMW} \\ &\qquad - \mathit{Contract\ Demand\ Quantity}) \end{aligned}$$

In this billing design, capacity is separated from energy billing by subtracting HLH load (which stands for Heavy Load Hour energy and is load that occurs from 6am-10pm Monday through Saturday), and the number is reduced further by a Contract Demand Quantity which is a volume of capacity for which there is no charge.

This rate design differs from the POC capacity billing which is given by the following equation:

Figure 5-5 POC Demand Charge Calculation

$$\begin{aligned} &Monthly\ Demand\ Charge \\ &\qquad = Monthly\ Capacity\ Price * (Peak\ Hour\ Load - Average\ Load\ in\ aMW \\ &\qquad - RICc\ capacity\ credit) \end{aligned}$$

The optimization model evaluates the expected load profile of the PUD given investments in resources that can reduce or reshape that load profile and feeds the load profile through the appropriate billing design for all months and years of the study period to calculate the Demand Charge. Investments that reduce demand, update forecasted BPA bills in the model, but the cost to acquire them is also factored in.

The PUD's monthly peak loads are served at a financial rate determined and defined every BPA rate period. A monthly peak load is defined by the maximum hourly load value in MW for any given month. This part of the BPA bill is called the Demand Charge.

Figure 5-6 Monthly Base Case Net System Peak below shows the median monthly peak load values before new cost-effective energy efficiency and demand response measures for the Base Case scenario in 5-year incremental snapshots from 2026 through 2045. The PUD is now and is expected to remain to have it annual peak in the winter months throughout the study period. However, the monthly summer peaks do grow at a faster rate relative to their starting point in 2026 than the winter peak growth rate.

Figure 5-6 Monthly Base Case Net System Peak

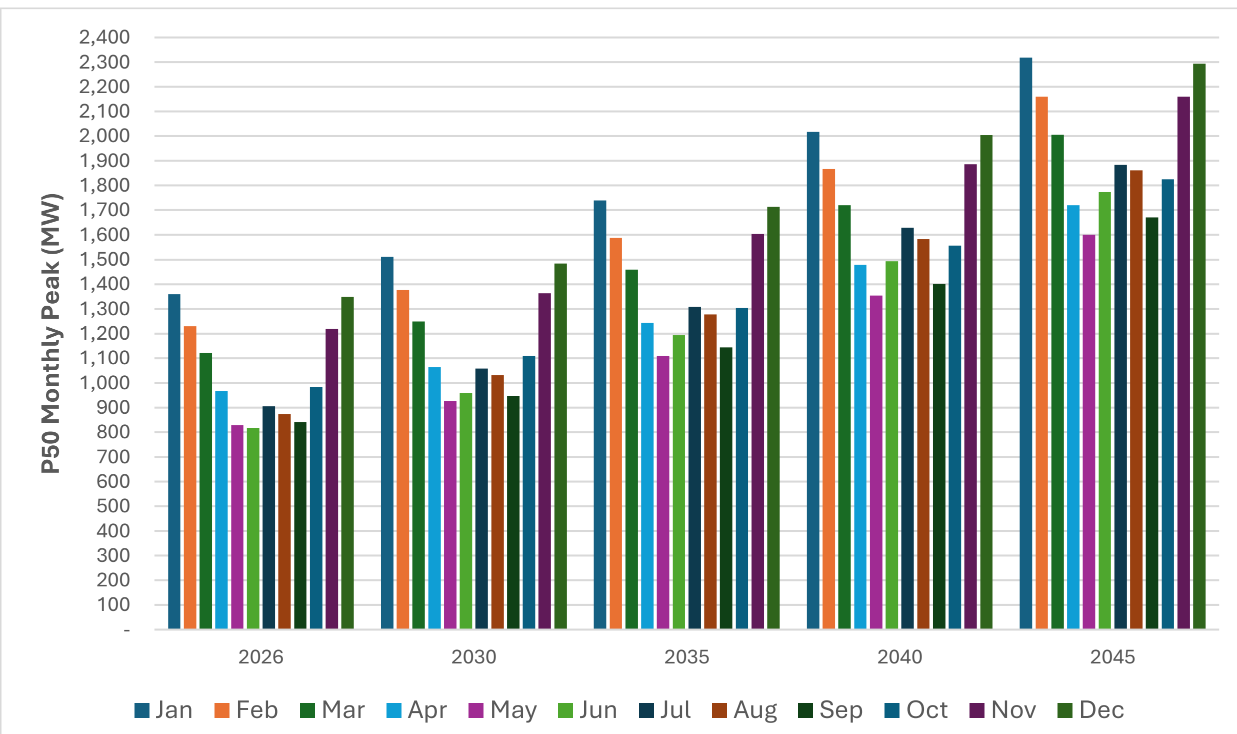
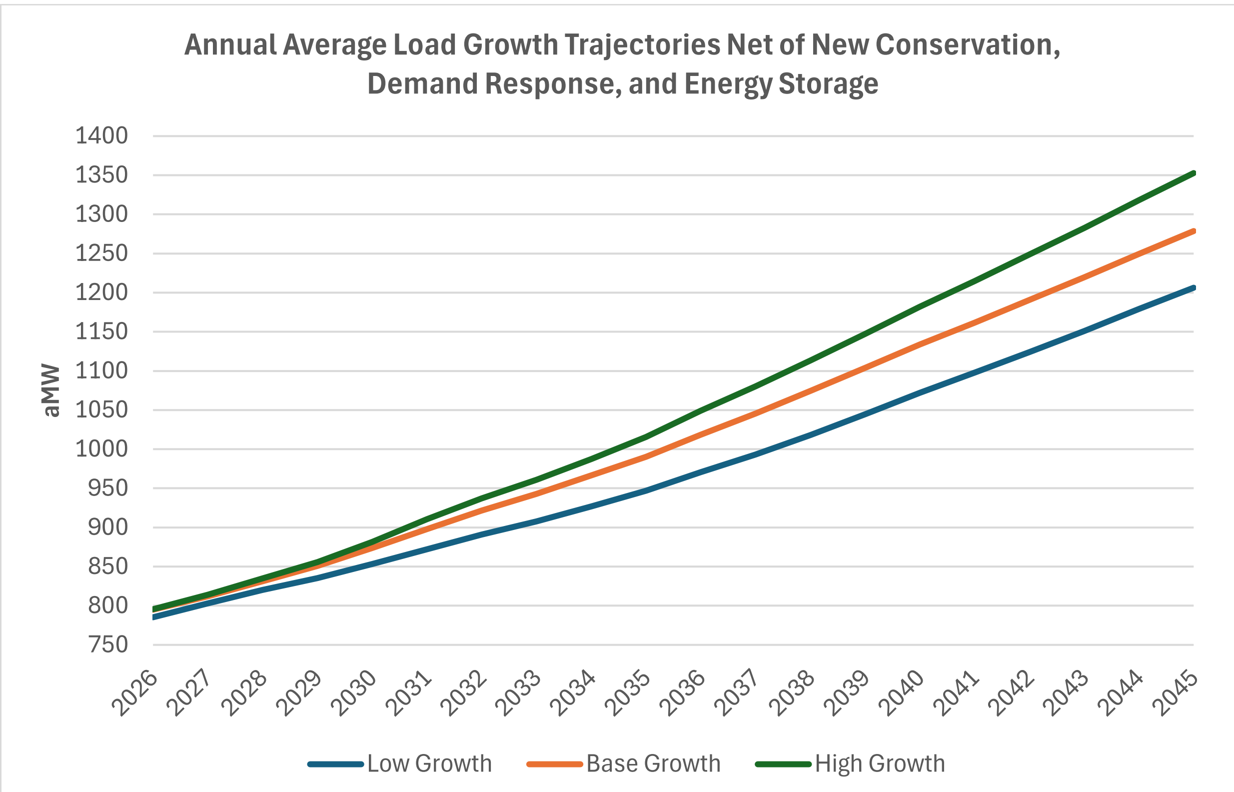


Figure 5-7 below shows the three unique annual peak load growth trajectories at the fiftieth percentile (P50) before new demand-side or supply-side resource additions. Each scenario or sensitivity utilizes one of these three load growth trajectories. Generally, the PUD forecasts annual peak load growth to outpace annual average load growth by approximately two times.

Figure 5-7 Annual Net System Peak Load Growth



The BPA monthly Demand Charge can be reduced by reducing the monthly peak load. The optimization process considers the cost and monthly peak reduction capabilities of demand-side and supply-side resources and compares those costs and capabilities against the price of BPA's established demand charge rate. If a resource can reduce the demand charge at a cost that is lower than what BPA would otherwise charge to serve that peak, then that resource could be considered cost-effective in that it drives down total portfolio costs.

Solving Energy Independence Act Compliance

The EIA, passed by Washington voters in 2006 as Initiative 937, requires electric utilities with more than 25,000 customers to pursue all cost-effective conservation and meet RPS targets. Utilities can comply with the RPS targets using any of the following three compliance methodologies.

- Target Methodology: Serve 15% of total retail load with eligible renewables and/or eligible RECs
- No Load Growth Methodology: Demonstrate no average annual retail load growth
- Cost Cap Methodology: Spend at least 4% of annual retail revenue requirement on eligible renewables or eligible RECs

The PUD is forecasting load growth in all scenarios, and analysis has shown that the cost cap methodology is more expensive than the target methodology. Thus, the target methodology is the most likely methodology for the PUD to comply with the EIA.

On July 27 of 2025, Washington Governor Bob Ferguson signed into law Senate Bill 5445 which creates a new compliance incentive under Washington's Energy Independence Act by enhancing the renewable energy credit utilities receive for certain distributed energy project generation. Previously, qualifying distributed generation could be counted at twice its actual electrical output toward RPS targets. The new law expands this by allowing "distributed energy priority" (DEP) generation projects such as solar on capped landfills, agrivoltaics, or non-utility-scale wind to count at four times their actual output, but only if they commence operation before December 31 of 2029, and are located on qualifying sites within the utility's service territory. This 4X multiplier provides significant compliance value. Energy storage and demand response were also given REC-equivalent value based on their nameplate capabilities, peak system load and total retail load as described below.

For purposes of meeting EIA RPS targets, the IRP recognizes the ability to buy large quantities unbundled RECs annually. However, to avoid overreliance on uncertain markets for these RECs, the IRP an annual ceiling on REC purchases as a model constraint to limit exposure to this compliance risk. For most scenarios and sensitivities including and Base Case, this ceiling is 750,000 RECs/year. The Shallow REC Market sensitivity intentionally halves this amount to test the Base Case portfolio resilience against an environment where unbundled RECs are sparse in the market.

The figures below show the PUD's forecast EIA compliance position given its current resource portfolio and REC market ceiling, before any new resources or new unbundled REC purchases for the Base Case scenario and Shallow REC Market sensitivity.

Figure 5-8 EIA Portfolio Needs Before Resources or REC Purchases

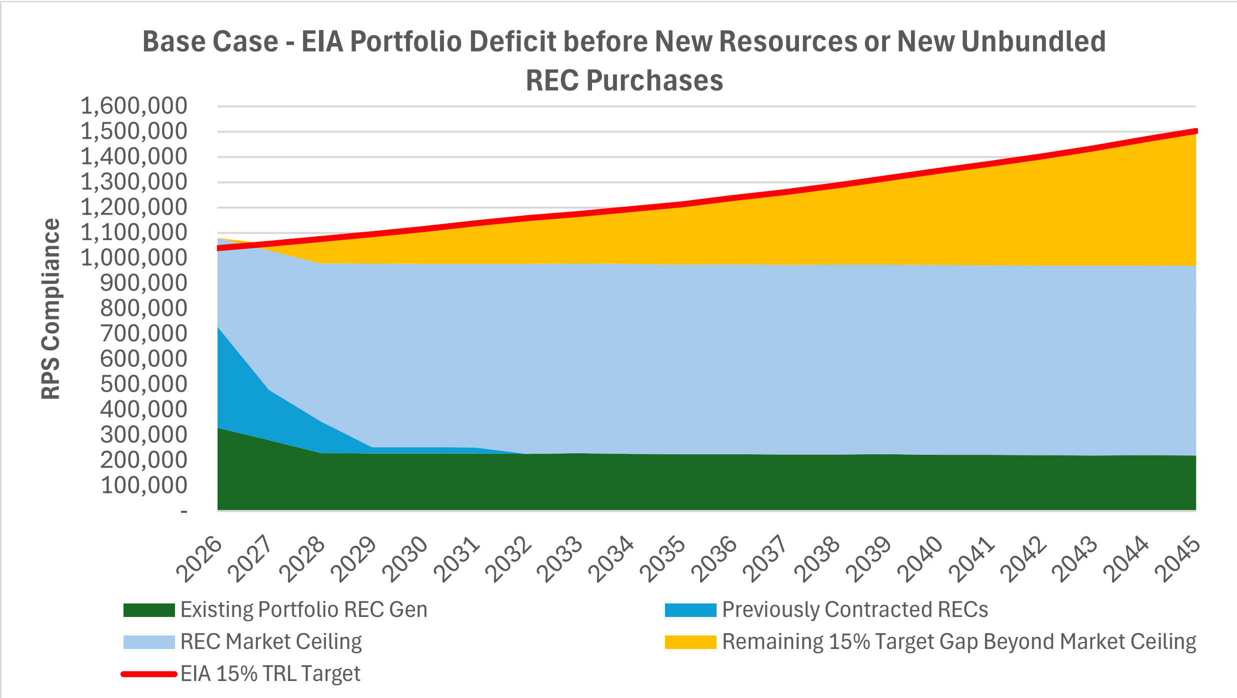
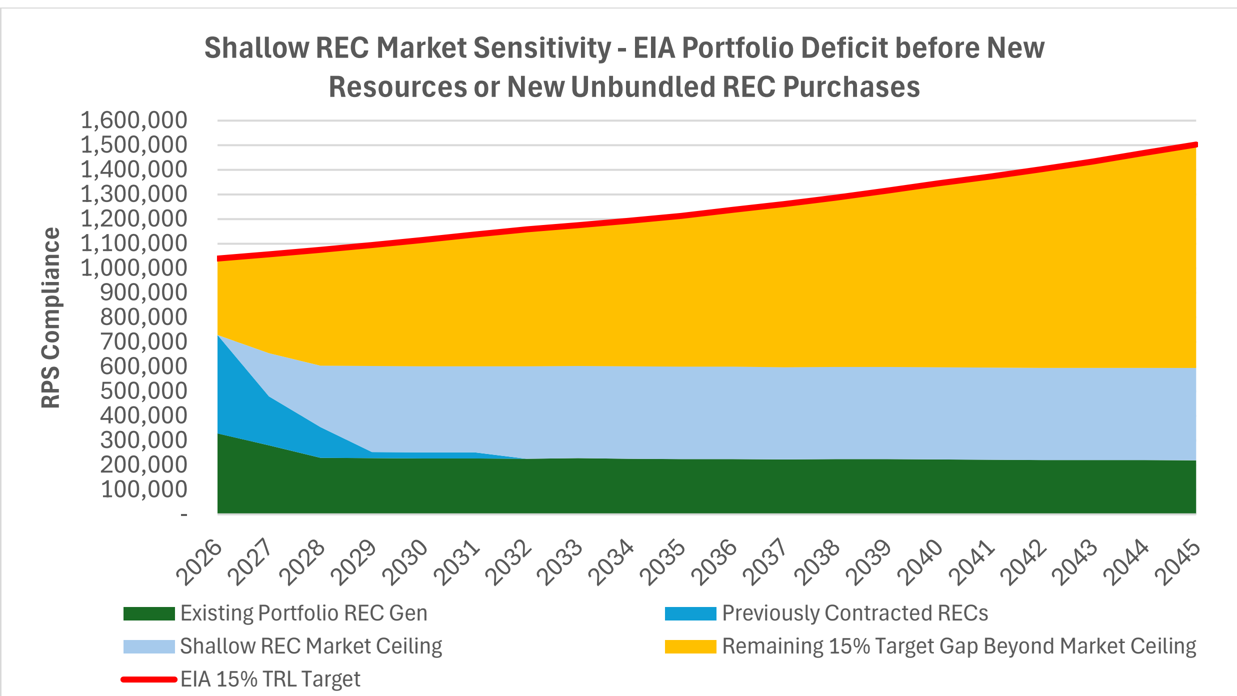


Figure 5-9 EIA Portfolio Needs Before Resources Shallow REC Market



To solve the RPS requirements above the market depth as shown in the figures above, new resources much be added to the portfolio to avoid non-compliance penalties. These resources have historically been energy efficiency (which lowers load and the RPS target volume of RECs) and eligible renewables such as wind and solar (which produce RECs). However, the newly passed SB 5445 allows demand response and certain types of energy storage to contribute toward EIA RPS targets, as well as enhancing certain types of newly constructed generation if in service before calendar year 2030.

All new resources for selection in the optimization process generate EIA compliance attributes in accordance with statute. The EIA allows eligible renewable projects under 5 MW nameplate capacity to be eligible for a 2X multiplier toward compliance, with new solar under 5 MW to be eligible for a 4X multiplier if placed in service before 2030. Battery energy storage and demand response contribute toward compliance via the following math equation.

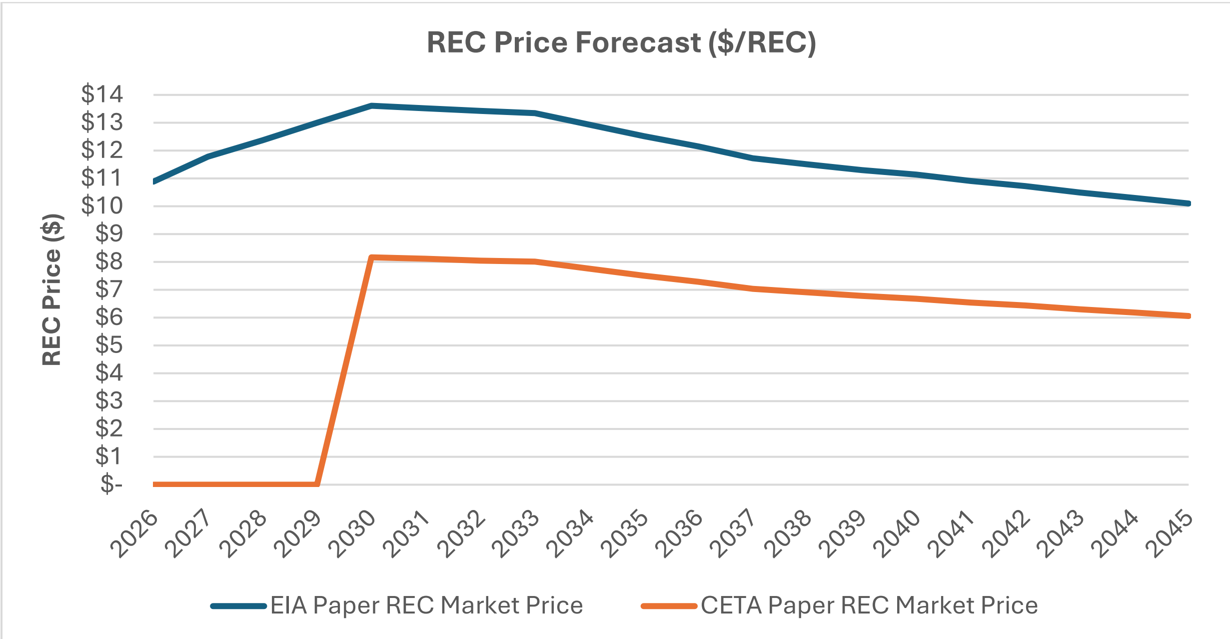
$$\frac{Peak\ Reduction\ Contribution\ of\ Resource\ (MW)}{Utility\ System\ Peak\ (MW)} \times Total\ Retail\ Load\ of\ Utility\ (MWh)$$

Where nameplate is the nameplate capacity of the resource in units of MW, peak is the adjusted annual system peak in units of MW, and TSL is the total annual system load in units of MWh. As an example, a 25 MW, 100 MWh battery energy storage facility would generate approximately 125,000 RECs per year given a 25MW peak reduction, 1,400MW system peak, and 7,000,000 MWh load. These peak and load values are roughly equivalent to the PUD today.

To solve for compliance needs the IRP uses unbundled RECs at a forecast market price with a ceiling to the volume available to be purchased from the secondary market. The optimization process solves for compliance needs by avoiding alternate or non-compliance penalties as required by the statutes.

The figure below shows the price stream for the Base Case scenario. This price stream was established using a Monte Carlo model developed in-house by the PUD and is based on a composite of market observations and market forecasts.

Figure 5-10 Base REC Price Forecast ($/REC)



Solving Clean Energy Transformation Act Compliance

The Clean Energy Transformation Act, or CETA, is a clean energy law enacted in 2019. It requires electric utilities in Washington State to:

- Eliminate retail electricity sales sourced from coal-fired facilities from their portfolios by 2025
- Ensure retail electricity sales are 100% greenhouse neutral and achieve 80% annual carbon-free retail electricity sales by 2030
- Achieve 100% annual carbon-free retail electricity sales by 2045

The PUD does not have coal in its portfolio and does not source from any coal-fired facilities. As a BPA Load-Following customer, the PUD will not directly transact in the wholesale energy market for balancing purchases. Instead, BPA will make balancing purchases on behalf of all customers it serves to augment its portfolio of resources. These BPA wholesale market purchases are the only source of non-renewable energy in BPA's portfolio. The PUD will receive RECs for BPA purchased power as part of the Post-2028 contract. The only portion of BPA Power not expected to come with RECs is the small share of power associated with BPA's wholesale market balancing purchases.

Figure 5-11 and Figure 5-12 below show the PUD's forecast CETA compliance position for the Base Case and Shallow REC sensitivities before any new resources, demand-side or supply-side, are added. Due to the overall nature of the PUD's current portfolio, the 80% clean energy target is annually met without needing to add any new clean energy resources until 2039. If the shallow REC market sensitivity is applied, then the need for new physical resources is accelerated to meet the clean energy target due to the sensitivity's restriction on unbundled REC purchases.

Figure 5-11 CETA Base Case Portfolio Position Before Resources or REC Purchases

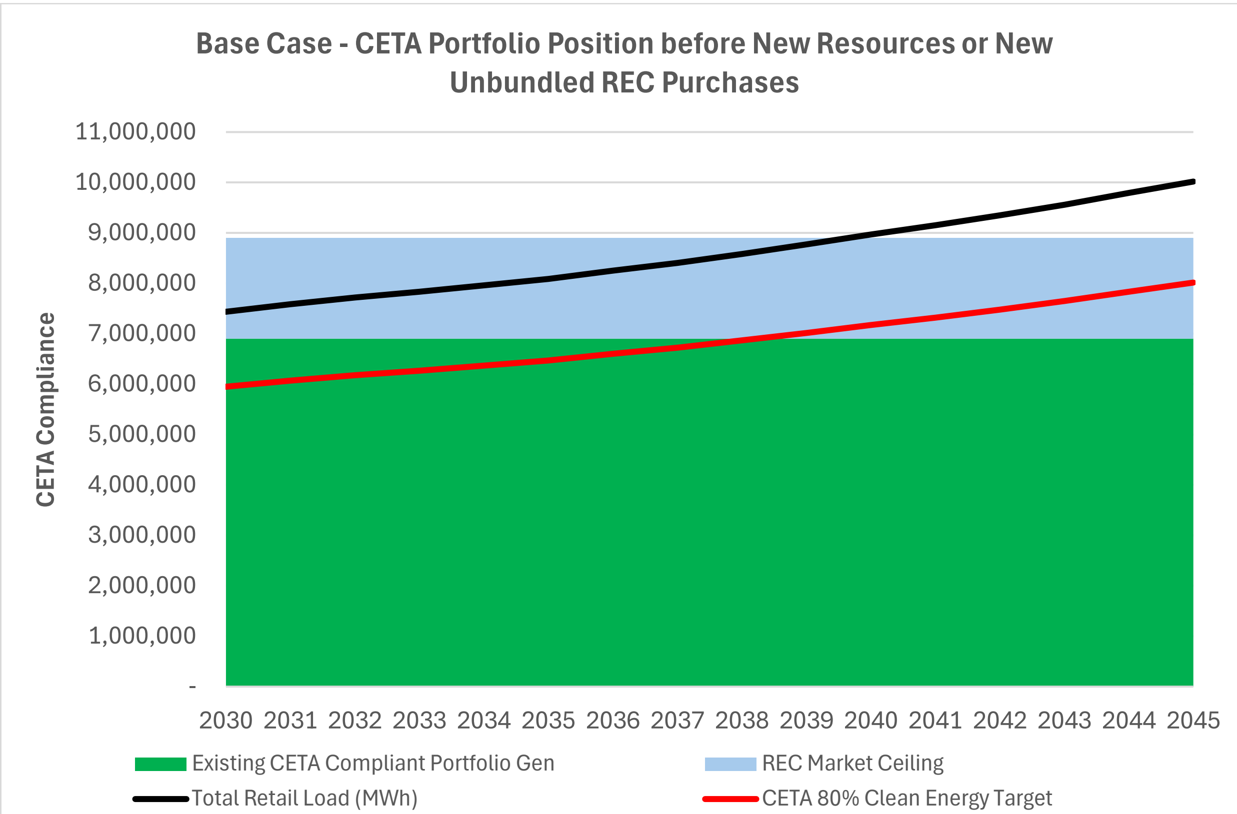
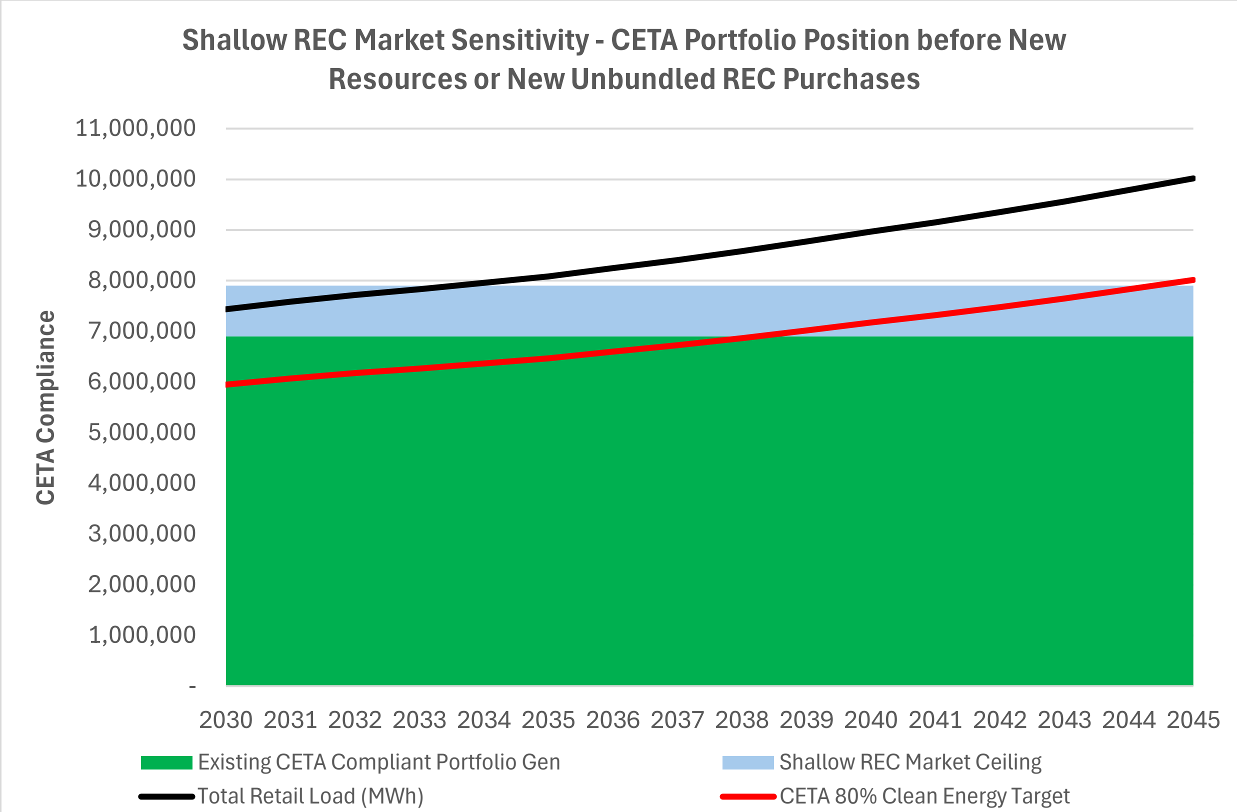


Figure 5-12 CETA Shallow REC Market Portfolio Position Before Resources or REC Purchases



Much like the EIA, CETA has a non-compliance penalty price that the optimization process avoids by adding a mix of new resources which result in the lowest portfolio cost NPV. The clean energy gaps as seen in the figures above is solved by incrementally adding new non-emitting resources, new energy efficiency, and/or purchasing new unbundled RECs.

Optimization Framework Summary

The optimizer considers the combination of regulatory compliance attributes, load serving attributes, load reduction attributes, cost-saving potential and cost of each potential new resource and weighs that combination against non-compliance penalties plus incremental BPA Tier 2 load serving costs to create a mix of resources which best meet regulatory compliance requirements and load serving needs at lowest portfolio cost NPV.

Resource Options

It is important to understand the differences among resource options available to serve future load growth and regulatory compliance needs while providing reliable, lowest reasonable cost electric service to the PUD's customers under a variety of futures. The 2025 IRP evaluated the relative costs and benefits of different types, sizes and time constraints of commercially available resources. Supply side and demand side resources were evaluated using the same measurements: their potential contributions to peak demand reduction, average energy, their potential in satisfying annual renewable compliance requirements and their cost. In this way, the PUD was able to use an integrated portfolio approach for each scenario, creating candidate portfolios that combined the best mix of demand and supply side resources to meet future need, based on least cost criterion.

Demand Side Resource Options

Demand-side resources are customer-based energy solutions that help manage energy and peak demand needs efficiently with investments in customer programs. Instead of increasing supply through new generation or infrastructure, demand side options reduce or shift energy use through programs like energy efficiency, demand response, and distributed energy technologies. By integrating demand side resources into the IRP as resource options, the PUD can lower costs, enhance grid reliability, and support sustainability goals while investing and partnering with our customers.

Conservation Potential Assessment

The PUD contracted for a utility-specific analysis with Lighthouse Energy Consulting, who conducted a 2025 Conservation Potential Assessment (CPA) study. The CPA identified all achievable technical conservation within the PUD's service territory over the 20-year study period.[13] The CPA was informed by: the PUD's past conservation achievements; Northwest Power and Conservation Council's 2021 Power Plan, customer characteristics supplied by the PUD, and program updates based on the Regional Technical Forum. The CPA informs the amount, type, and availability of conservation measures, their associated savings, and costs.

The CPA assessed each achievable technical conservation measure and sorted the measures into sixteen different bundles by levelized cost per bundle. The two types are annual measures and winter measures, where annual measures reduce load on more of an annual basis, and winter measures generally reduce load in just the winter months of November through February. The sixteen bundles are split 8 for winter and 8 for annual

[13] A full description of the conservation resources available to the PUD can be found in the PUD's 2025 CPA Report.

conservation programs. These bundles were then used to determine the amount of conservation that is cost-effective, alongside supply side resource options, using an integrated portfolio approach for each scenario.[14] Figure 5-13 shows the relationship between technical, achievable and economic potential.

Figure 5-13 Types of Energy Efficiency Potential

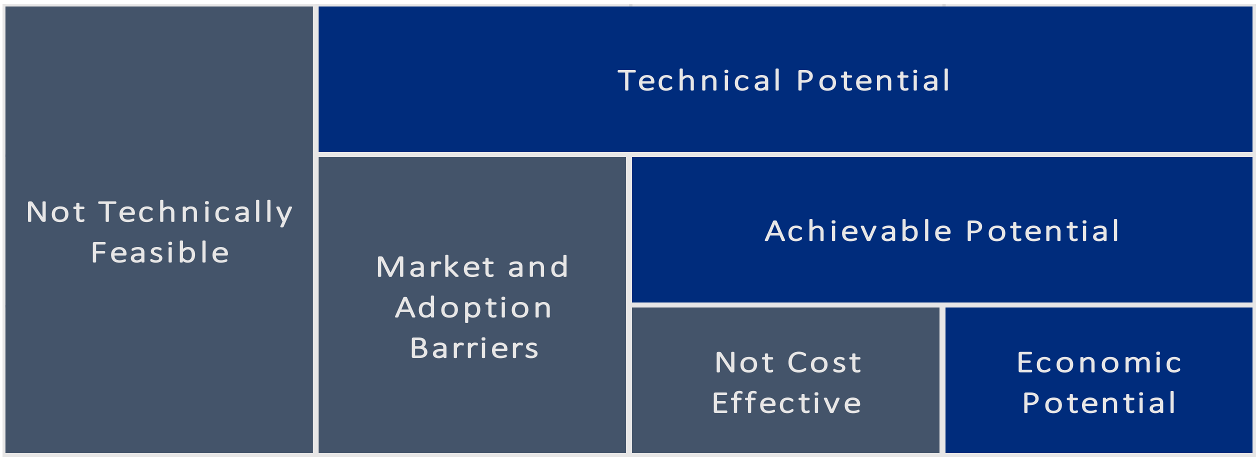


Figure 5-14 and Figure 5-15 illustrate the 2025 CPA's conservation supply curve, separated by bundle. This supply curve facilitates comparison of demand-side resources to supply-side resources. Each section in the chart below represents the amount of achievable technical conservation potential (annual or winter as measured during December On-Peak Hours based on end use profiles) and a demand side resource option available for selection in the 2025 IRP analysis.

[14] The integrated portfolio analysis was performed in the development of the portfolios via the optimization process.

Figure 5-14 Cumulative Annual Achievable Technical Potential Supply Curve 2026-2045

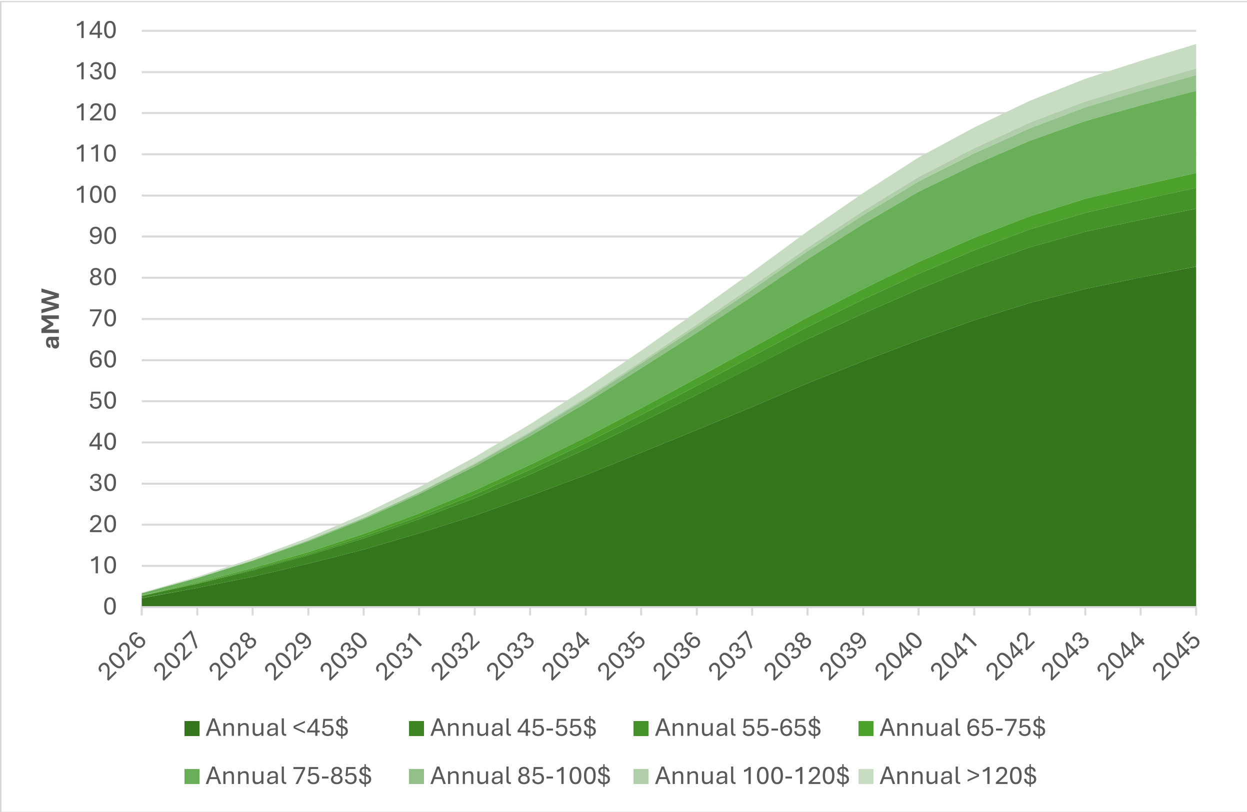
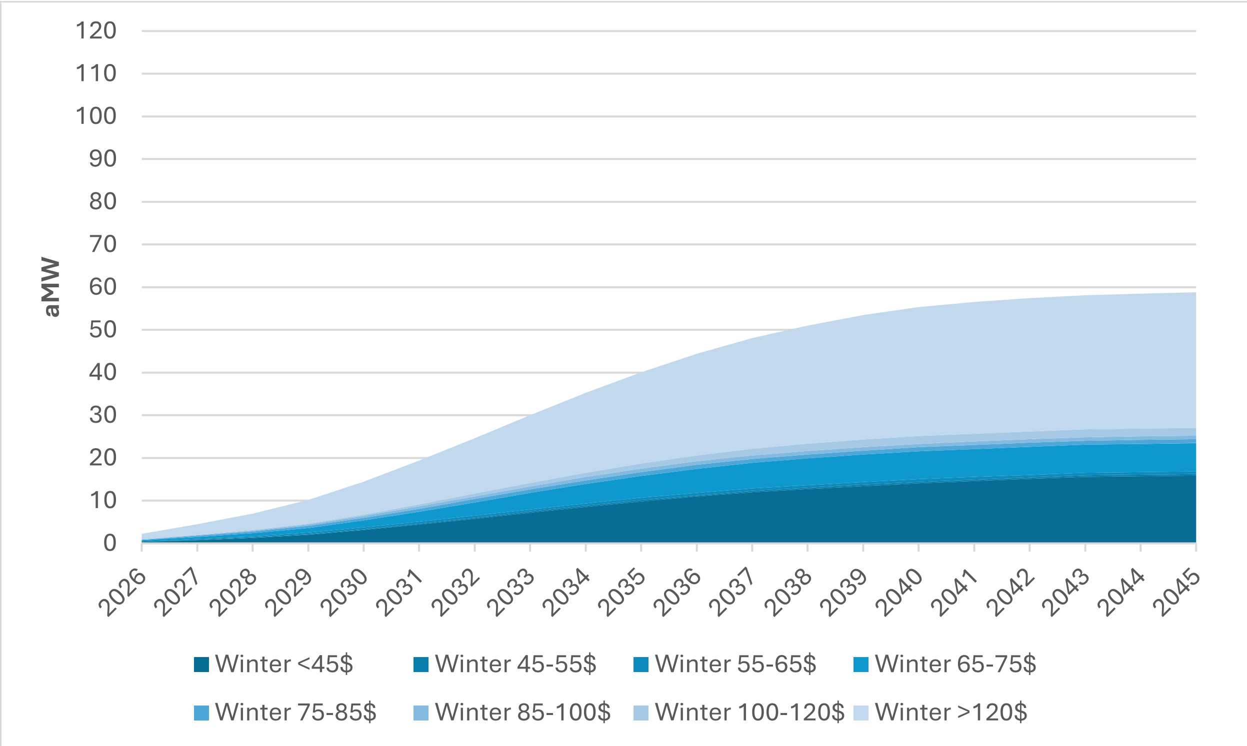


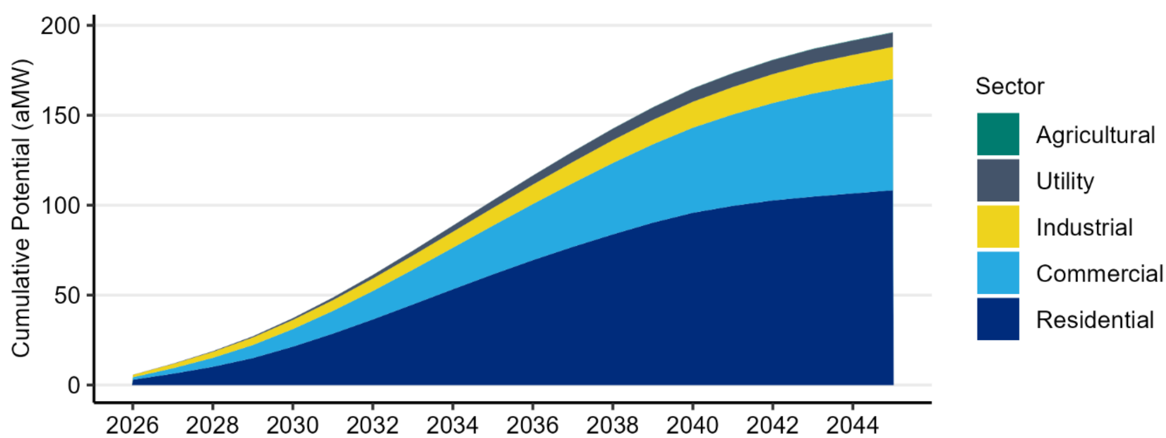
Figure 5-15 Cumulative Winter Achievable Technical Potential Supply Curve 2026-2045



Bundle 1 represents the conservation measures identified at a levelized cost of $45/MWh or less that have a total of achievable technical potential of 82 aMW in annual energy savings over 20 years, and 15 aMW of winter benefit over 20 years. The stacked bars in Figure 5-16 below show total cumulative conservation grouped by levelized cost in $/MWh. The total technical achievable conservation is 137aMW of annual savings and 59aMW of winter savings for a total of 196aMW cumulative conservation. This represents the maximum amount of total achievable technical conservation savings that could be achieved over 20 years (through 2045).

The residential sector accounts for approximately 55% and the commercial and industrial sectors account for 31% and 9% of achievable technical conservation potential, respectively. The balance of potential is in agricultural and distribution efficiency measures. Over 20 years the PUD's total potential peak reduction from technical achievable conservation could be up to 359.8 MW. The 2-year total potential peak demand savings for total technical achievable conservation is 22.1MW. Figure 5-16 shows cumulative total achievable technical potential in aMW distributed by sector.

Figure 5-16 20 Year Achievable Technical Potential by Sector



Demand Response

Demand Response programs entail coordination with customers to alter their energy consumption patterns to help the PUD defer or shift customer demand in a time with peak load pressure to a time with less peak load pressure. An example of this type of program is described in the NWPCC's 2021 Power Plan as Time of Use (TOU) rates where energy rates vary throughout the day between peak times and off-peak times to shift demand out of peak hours. Demand Response is increasingly viewed as a significant resource in the region to temporarily assist with meeting peaking and system flexibility and reliability needs.

Demand Response Potential Assessment

As part of the 2025 IRP effort, the PUD contracted with Lighthouse Energy for a 20-year demand response potential assessment (DRPA) to identify demand response potential by product and levelized cost to inform the potential demand response programs in the resource options. The IRP economic optimization process takes the program costs and peak demand impacts to determine the cost-effective potential. The DRPA generally followed the methodology used by the NWPCC in the 2021 Power Plan and included many of the same demand response (DR) products, plus several additional products the PUD is considering. The DR products included in this DRPA are applicable to the commercial, industrial, and residential sectors, impact both the summer and winter seasons, and utilize a range of strategies, including direct load control, customer-initiated demand curtailment, and time-varying prices to effect reductions in peak demand.

Like a conservation potential assessment, the DR potential calculation process began with the quantification of technical potential, which is the maximum amount of DR possible without regard to cost or market barriers. The assessment then considered market barriers, program participation rates, and other factors to quantify the achievable potential. As with the conservation potential assessment, the achievable potential assessment did not include an economic screen to determine cost-effectiveness. Instead, the results of this assessment were provided as inputs to the 2025 IRP process, which determines the level of cost-effective DR resources through economic optimization across a variety of demand and supply-side resources using the integrated portfolio approach. Figure 5-17 provides an overview of the types of programs, their sector association, and their broad program categorization.

Figure 5-17 Demand Response Programs Across Sectors

	Commercial	Industrial	Residential
Direct Load Control	Space Heating Switch Smart Thermostat		EV Charging Water Heater Controls Space Heating Switch Smart Thermostat Behind the Meter Batteries
Demand Curtailment		Demand Curtailment	
Time-Varying Prices	Time of Use Rates Critical Peak Pricing	Time of Use Rates Critical Peak Pricing	Time of Use Rates Critical Peak Pricing

The DRPA found the majority of technical potential originates from the residential sector, in alignment with prior DRPA studies. The estimated total achievable winter peak hour demand response is 110MW with 93MW of that supplied from the residential sector. Peak loads are highly correlated with residential load during the winter months when the PUD typically has the highest peaks, while commercial loads tend to peak during the summer month and industrial loads are generally flat. Commercial and industrial loads have less capacity to reduce or shift loads and participation is limited in demand response programs leading to lower potential in the winter. Total summer potential is 126MW with 95MW of the total provided by the residential sector. New to this DRPA is the utility sector demand voltage reduction enabled by communications infrastructure deployed with the SNOSmart Grant.

Figure 5-18 Winter DR by Sector

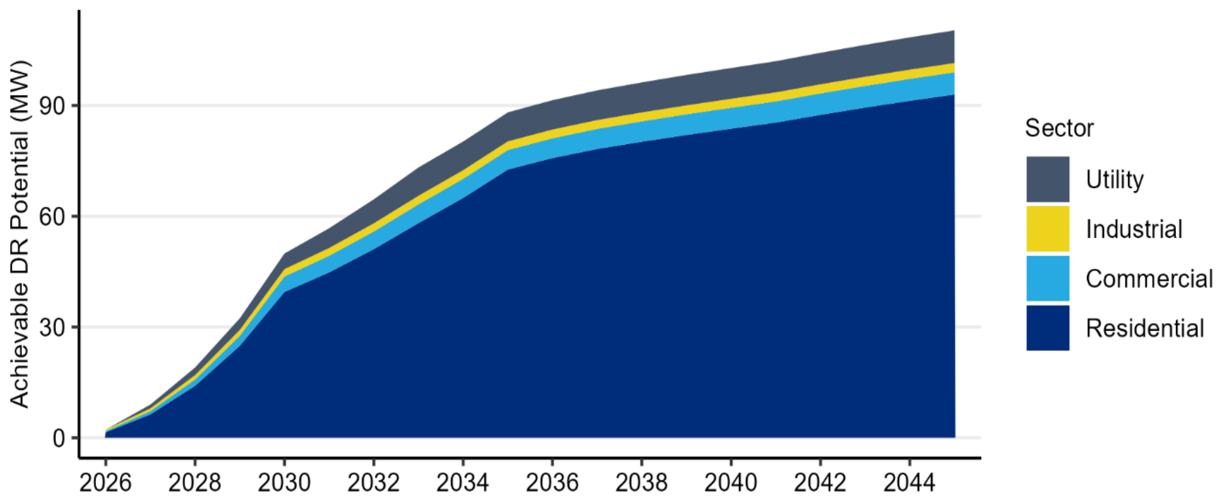
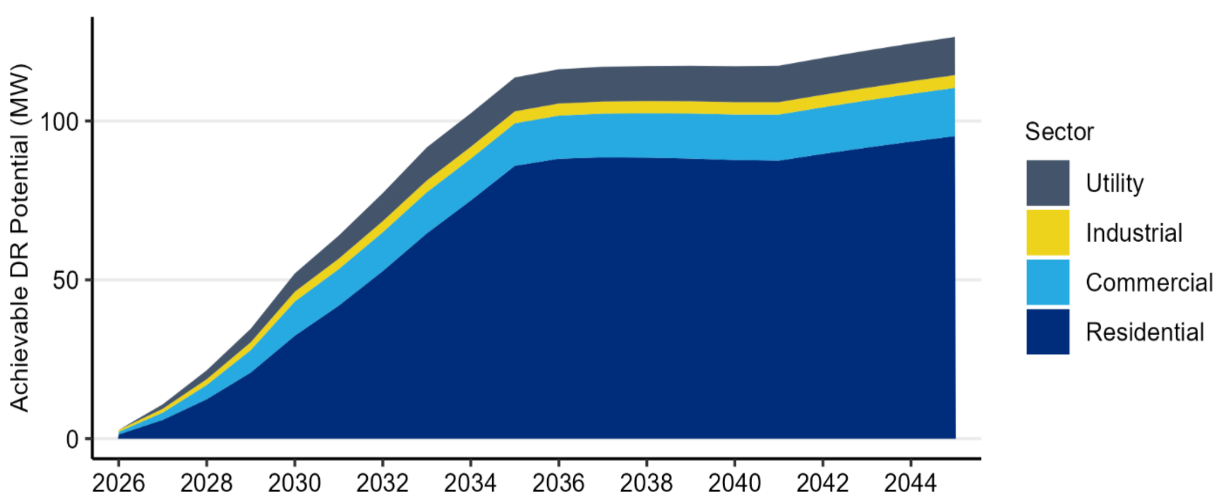


Figure 5-19 Summer DR by Sector



The potential is spread evenly across the categories of space heating, water heating, EV charging, and the all end use. The all end use includes pricing products, curtailment strategies, and DVR, whose impacts are not specific to a single end use. The growth rates for each end use reflect different rates of eligibility for different types of equipment. The growth in potential from EV charging is driven by the forecasted adoption of electric vehicles. The DR potential in water heating is impacted by the adoption of heat pump water heaters, which provide energy savings throughout the year but less callable load reductions for demand response. Growth in the all end use is based on the rollout of curtailment programs as well as the planned implementation of AMI and price-based programs.

Figure 5-20 Winter DR by End Use

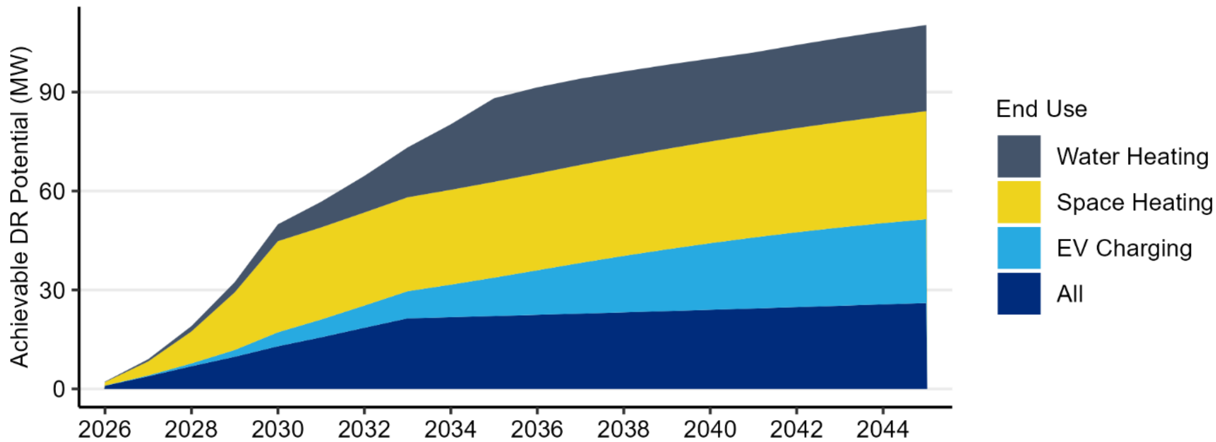
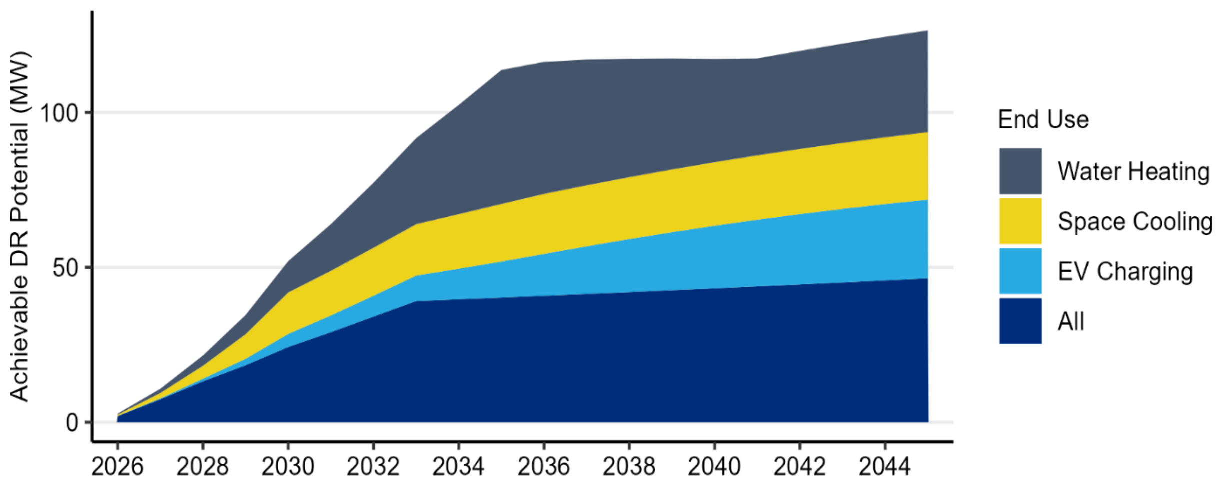


Figure 5-21 Summer DR by End Use



The costs associated with the studied demand response programs are detailed in the demand response supply curves. These supply curves show the quantity at different cost thresholds and are shown below for winter and summer programs. The dark area represents the incremental addition while the light blue area shows the cumulative potential from previous products.

Figure 5-22: Winter DR Supply Curve (MW and $/kW-year)

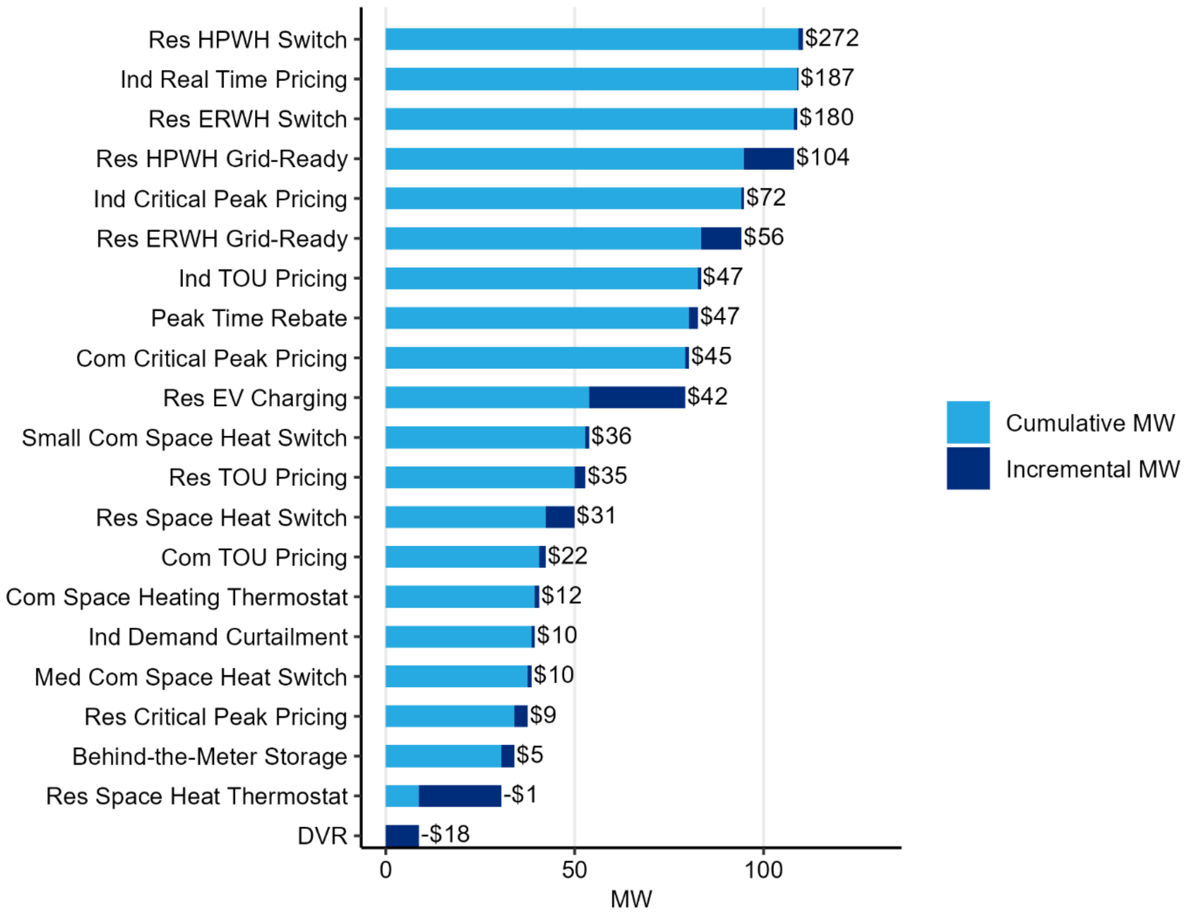
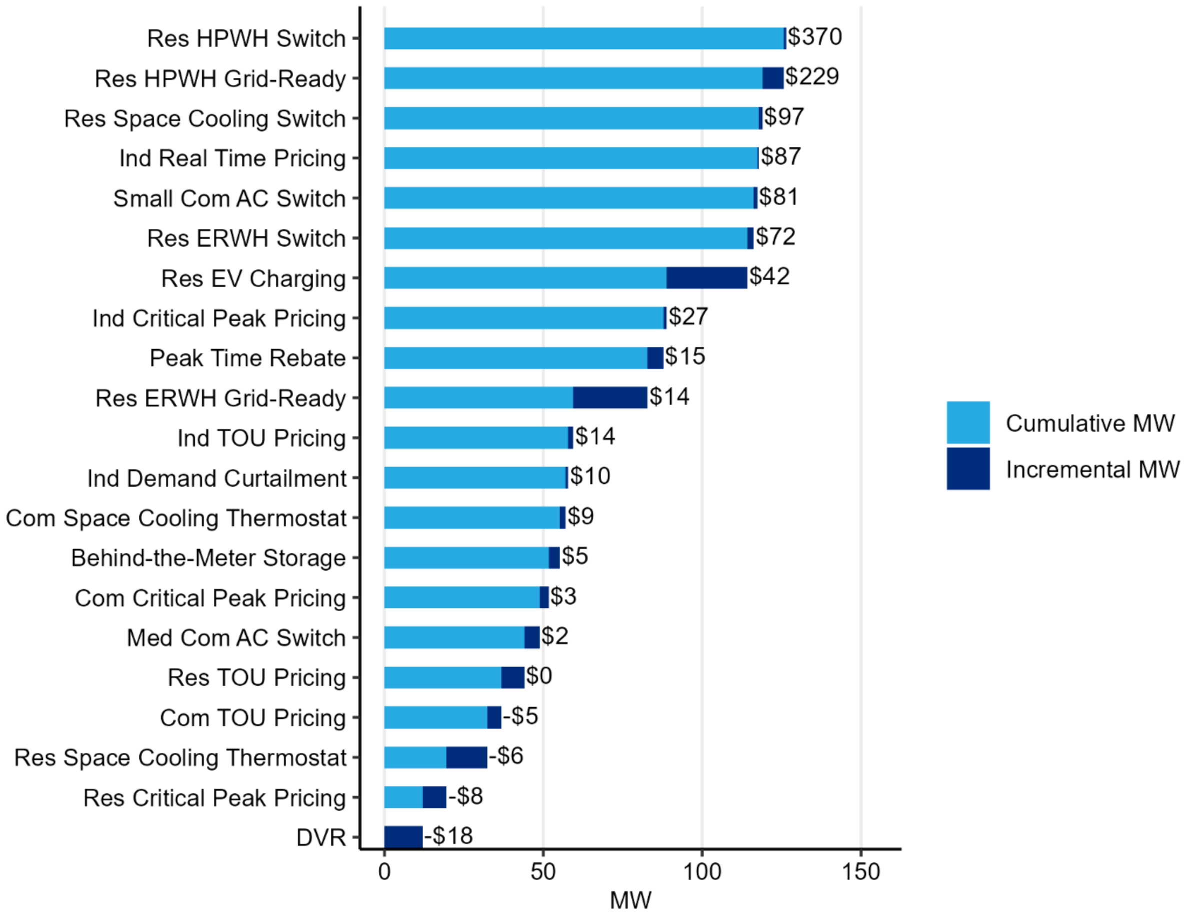


Figure 5-23 Summer DR Supply Curve (MW and $/kW-year)



One unique attribute of some demand response programs is that they are call-limited, meaning they cannot be freely called upon. Rather, the programs have a set number of calls that can be made upon participating customers. Due to this limit, the contributions of demand response programs are likely limited based on the PUD's ability to predict peak demand hours. The demand construct for the Load-Following product depends on the monthly peak hour demand and to the extent demand response is time or call limited its effect is discounted. Utility controlled products such as demand voltage reduction (DVR) and passive rate constructs are better positioned to meet the monthly peak hour demand. New to this IRP is WA State Bill 5445 which grants environmental policy compliance attributes based on the demand response program's ability to meet the annual system peak multiplied by the annual system load. Operational control and dispatch considerations are not considered in the IRP, only the capabilities and characteristics were included in the study.

Solar Potential Assessment

Consistent feedback from PUD customers through the public process during this IRP and prior IRPs is a desire to include more rooftop solar incentives and options in the potential supply options. In 2023 the PUD included a one-time incentive to increase solar adoption rates and advance rooftop solar development in the early part of the study. This was found to be not cost-effective however staff determined a more rigorous study should be performed. The Solar Potential Assessment (SPA) study was performed for the PUD by Nauvoo Solutions in parallel with the CPA and DRPA studies and represents a new method of examining rooftop solar potential. By studying rooftop solar as a resource instead of as a load modifier the SPA gave new insights into sectors and values that were incomplete prior to performing the study.

The SPA used several sources for data which include the National Renewable Energy Laboratory (NREL) for solar irradiance (pvwatts), payback curves (Distributed Market Generation Demand Model, dGEN), expected growth rates (ATB) and rooftop square footage data (dGEN). Rooftop solar capital costs are from Lawrence Berkley National Lab and the PUD provided existing rooftop solar penetration, rate structures and average system size. The SPA examined three incentive levels across three sectors to determine if incentivizing rooftop solar installations would be a way to reduce costs to PUD customers. The three sectors examined were residential, small C&I and medium C&I characterized by system size of 7.37kW, 16.63kW and 55.20kW respectively. The descriptions of these sectors do not necessarily reflect the customer or installation site but rather is only differentiated on system size where small and medium C&I installations are much larger than typical residential installations. The three incentive levels are described in Table 5-1below.

Table 5-1 Solar Potential Assessment Incentive Levels

Sector	Average System Size (kW)	Base Incentive (% of System Costs)	Incentive Level 1 (% of System Costs)	Incentive Level 2 (% of System Costs)
Residential	7.37	0	15	25
Commercial – Small Load	16.63	0	10	25
Commercial – Medium Load	55.20	0	40	50

All scenarios included tax credits based on current policy at the time of writing, in common with other resource options. Finally, total societal costs were used for the NPV costs in common with the CPA methodology, which includes non-energy values and benefits. Using societal costs as the metric for costs means the given costs are not necessarily the same as utility costs. The three charts below show the effect of incentive levels on solar installation in aMW for each sector.

Figure 5-24 Residential Solar Potential by Incentive

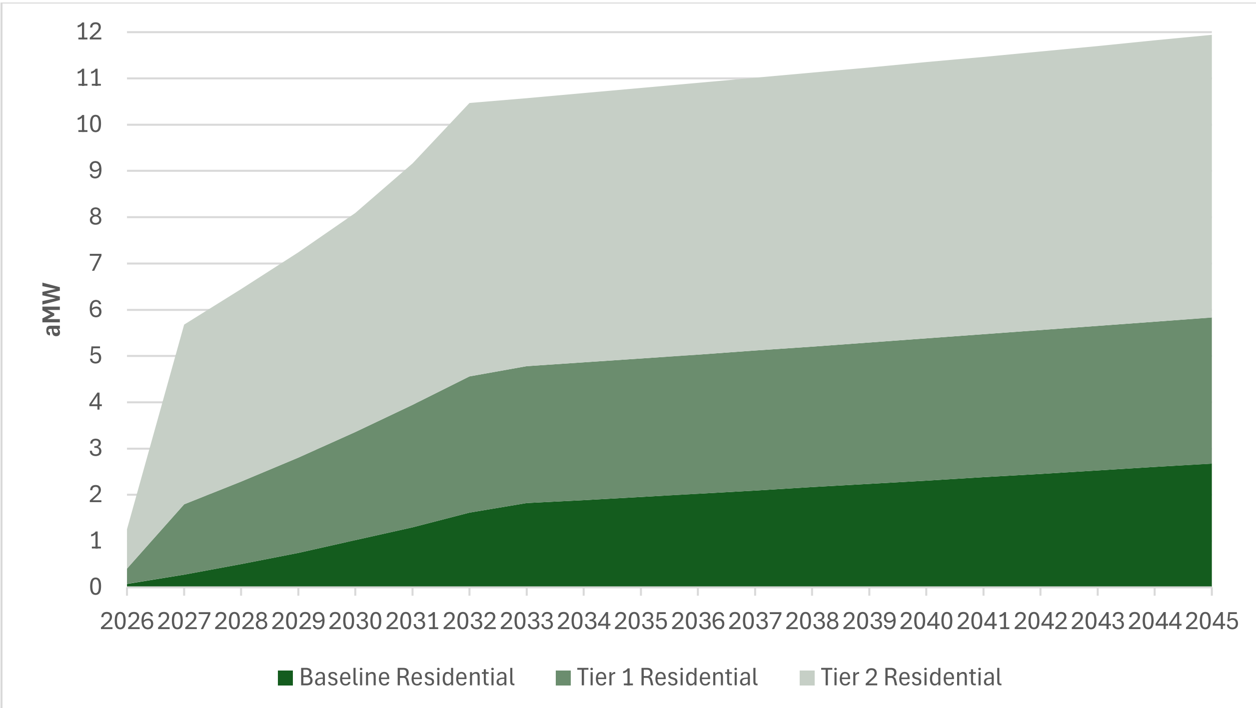


Figure 5-25 Small Commercial and Industrial Solar Potential by Incentive Level

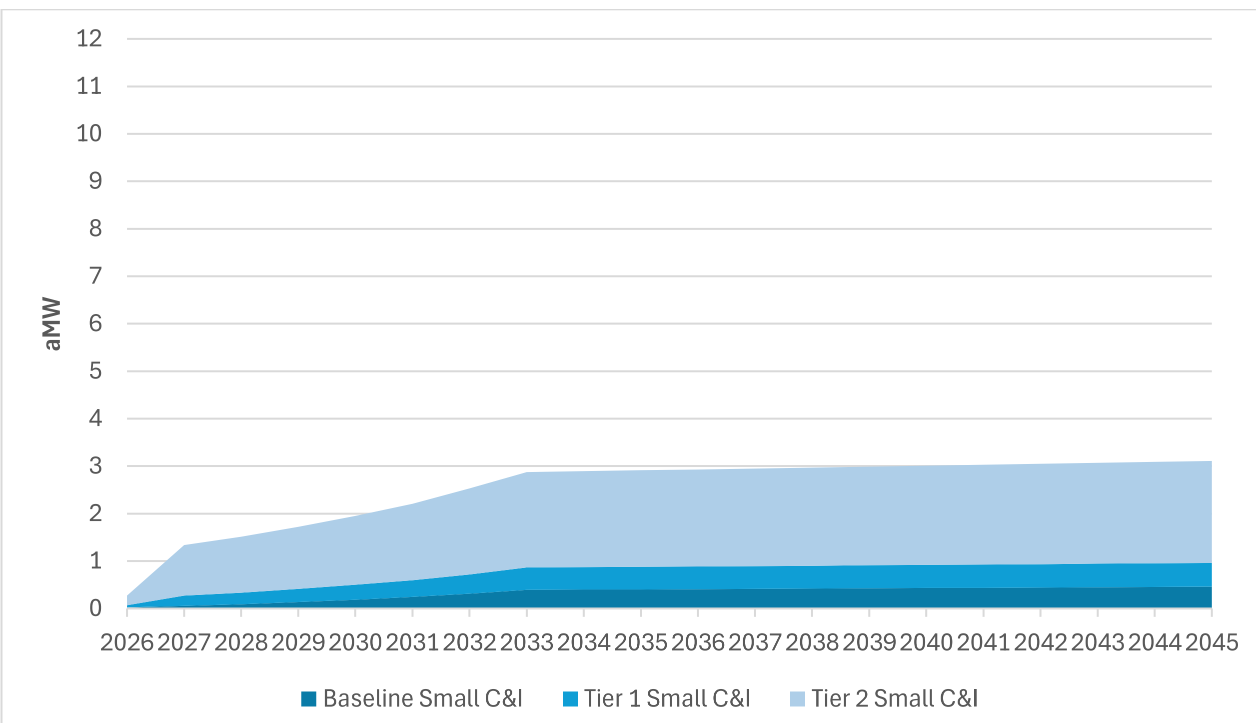
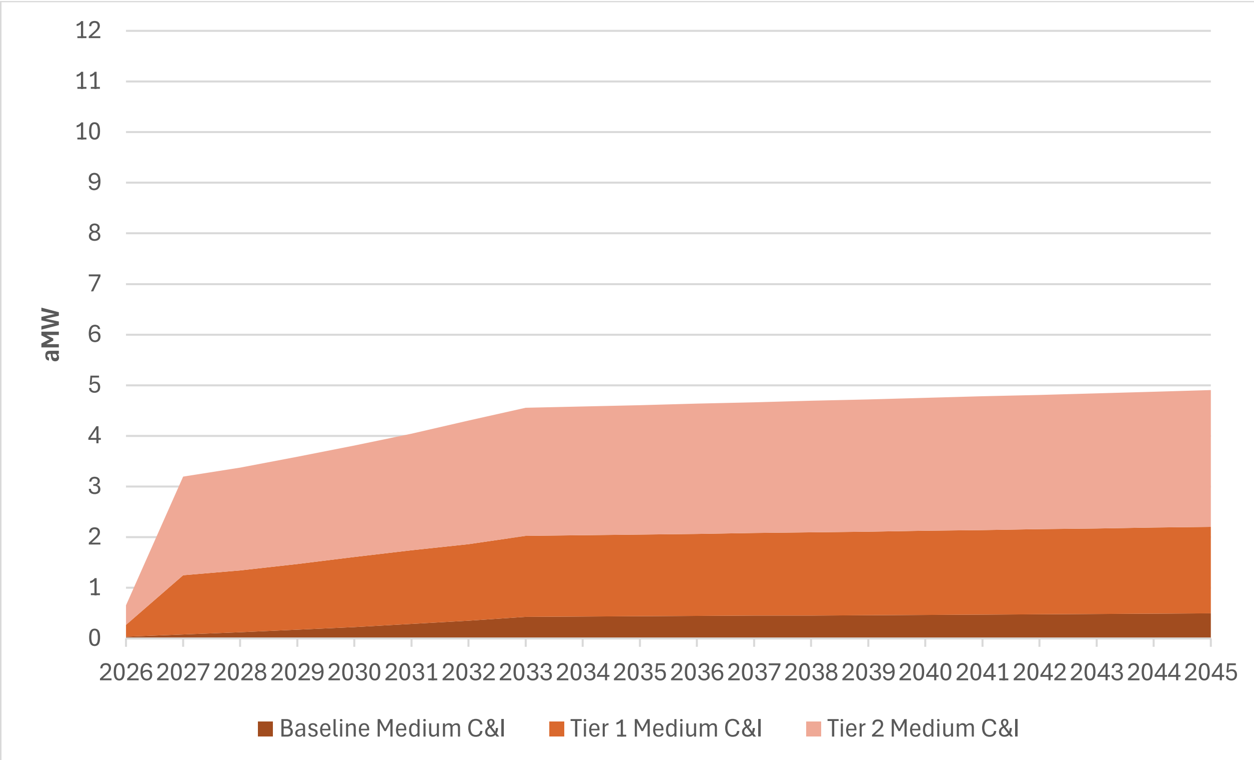


Figure 5-26 Medium Commercial and Industrial Solar Potential by Incentive Level



The incremental additions for each sectors incentive levels in 2045 at the end of the study period over the base, non-incentivized growth. The residential sector has the highest potential under all incentive levels which is unsurprising, however it also has the highest cost. Medium load commercial systems have the lowest societal costs however the volume of both small C&I and medium C&I are comparatively small relative to the residential sector.

Table 5-2 Solar Potential by Sector and Incentive in aMW by 2045

Sector	Baseline aMW	Tier 1 aMW	Tier 2 aMW
Residential	2.675	3.159	6.108
Commercial – Small Load	0.458	0.501	2.149
Commercial – Medium Load	0.496	1.707	2.701

Table 5-3 Solar Societal Costs by Sector and Incentive ($/W)

Sector	Baseline Societal Cost	Tier 1 Societal Cost	Tier 2 Societal Cost
Residential	$108.26	$113.13	$114.54

Commercial – Small Load	$98.09	$102.25	$103.20
Commercial – Medium Load	$53.75	$57.75	$57.43

Supply-side Resource Options

The PUD's integrated portfolio approach to planning for the future sets demand-side resources, market resources, and supply-side resources as a menu of options for the 2025 IRP's economic optimization model to choose from as it seeks the lowest net cost portfolio to meet the PUD's portfolio needs. Supply-side resources are resources that generate or store energy, as well as BPA provided energy. There are a wide variety of available resource types available across the Pacific Northwest, and consideration of these resources requires an assessment of their commercial availability, generating attributes, regulatory compliance values, development costs, and operating costs. The PUD screens resources for their commercial availability based on a staff assessment of whether a resource could be permitted, built, and have available market cost estimates. Some resources, such as coal plants, are not considered commercially available for the purposes of the 2025 IRP because energy policies create a reasonable doubt as to whether they would be permittable, as well as impose significant regulatory costs. Other technologies, such as hydrogen turbines, tidal generation, and new battery technologies, show promise but are not yet fully commercially available. Any nascent resource not deemed commercially available for use or further analytical consideration the IRP portfolio is deemed an "Emerging Technology" and can be found in Appendix F. Emerging Technologies

Supply-Side Resource Types

The 2025 IRP classifies supply-side resources into three categories: baseload resources, variable resources, and dispatchable resources. Baseload resources have a generation profile that is relatively stable and similar across hours of the day and across months of the year. An example of a baseload resource is a nuclear energy project, or a variable renewable energy project paired with energy storage to smooth and stabilize output. Variable energy resources have a generation profile that varies throughout the day and may have seasonal differences in the amount of energy that might be produced across months in a year. An example of a variable resource is a solar generation facility. Dispatchable resources can be controlled to dispatch into targeted hours of the day based on utility needs. An example of a capacity resource is a utility-scale battery. BPA Tier 2 service is not included in the traditional supply side resource options but is an option discussed later in this section.

Baseload Resources

The 2025 IRP evaluated baseload resources listed in Table 5-4. Renewable energy with on-site storage acts to smooth the output of the otherwise variable resource, and both Wind+Storage and Solar+Storage were considered. The storage is assumed to be 50% of the renewable energy nameplate with energy storage capacity for 4 hours. Total energy storage for each solar and wind baseload unit was 25MW/100MWh. Small modular reactors are modeled as first available in 2038 and the model assumes the PUD could be a contracted energy off-taker for a portion of a project but would not be a project owner. The 2025 IRP includes fusion energy in the final 5 years of the study period, in common with the 2023 Update. Snohomish County is home to a growing fusion energy sector with multiple local companies contributing to technological advances. Fusion energy is given a deliberately cautious first year availability date and the prices are assumed to be at a similar rate as renewable energy resources. This treatment enables the PUD to consider whether fusion could be a good fit in the distant future and enables the PUD to proactively develop long-term relationships with local partners in the event commercial projects can be developed with layers of community benefits. Geothermal generation is part of the resource options for the first time in the 2025 IRP in 2038, acknowledging the regional research in geothermal energy. Geothermal in the IRP is modeled as a blend of flash and binary systems with an associated blended cost of both types. Enhanced Geothermal Systems (EGS) was not included and is discussed in the emerging technologies appendix. Natural gas baseload plants are included for comparison only.

Table 5-4 Baseload Resource Options

Resource Type	Fuel Source	Nameplate MW	Units Available	First Year Available
Utility Scale Solar + Storage	Solar	50	4	2028
Gorge Wind + Storage	Wind	50	4	2028
Montana Wind + Storage	Wind	50	4	2028
Geothermal	Geothermal Heat	40	1	2038
SMR Nuclear	Nuclear Fission	50	1	2038
Fusion	H2 Fusion	50	1	2041
Natural Gas Combined Cycle	Natural Gas	50	1	2026

Variable Energy Resources

The 2025 IRP evaluated variable resources listed in Table 5-5. The traditional variable resources, solar and wind have been modeled in prior IRPs and represent the common utility scale resources. Solar and wind projects in this section do not have paired storage and are stand-alone energy projects. The 2025 IRP considered two run-of-river hydroelectric plant options: one new stream development and one buyout of an existing project. Both options were assumed to in Western Washington and modeled on existing PUD owned projects. The new stream development option would be within the Snohomish PUD service territory while the existing buyout would be outside the service territory. Each of these options have a capacity factor of 27%. Two local solar types are modeled based on two policy environments. These are 5MW solar plants located in Snohomish County on existing utility infrastructure sites or existing capped landfills. WA State Bill 5445 grants additional clean energy credits for regulatory compliance if completed before 2030. The 2028 BPA contract includes concessions for small, behind-the-meter resources up to 5MW combined total. These first 5 MW nameplate do not impact net requirements and do not require resource support services. To capture both policy environments two local solar projects were included. These different policy environments give rise to the two local solar options. Each local solar project has a capacity factor of 17% based on NREL capacity factors for Western Washington and data from the PUD's current local solar projects. Eastern Washington Solar is modeled at utility scale with a capacity factor of 30%. Two locations for wind projects are modeled in the IRP, one in the Columbia River Gorge and the other in Western Montana. Columbia Gorge wind capacity factors are based on the PUD's experience with several projects in the area and NREL wind speed class, giving a blended capacity factor of 38.7%. Montana wind is less developed than Gorge Wind, however several prospective projects exist. Montana wind has a capacity factor of 44.7% with higher variability and operates across seasons rather than primarily during the summer months.

Table 5-5 Variable Energy Resource Options

Resource Type	Fuel Source	Nameplate MW	Units Available	First Year Available
2026 Local Solar	Solar	5	1	2026
2030 Local Solar	Solar	5	1	2030
Run-Of-River New Development	Hydro	7.5	1	2032
Run-Of-River Buyout	Hydro	7.5	1	2028

Utility Scale Solar	Solar	50	5	2028
Gorge Wind	Wind	50	5	2028
Montana Wind	Wind	50	5	2028

Dispatchable Resources

The 2025 IRP considered the dispatchable resources in Table 5-6. Dispatchable resources impact the PUDs demand costs but do not impact average energy needs and, in some cases, add load as any charging energy required was accounted for in attributes. Dispatchable resources were given discounts to capacity based on dispatch duration and its ability to reliably be dispatched to meet peak hour needs. Longer duration resources have more ability to meet peak hour demands and are given more capacity attributes. In the summer season of 2027 WRAP becomes a binding program for entities choosing to join, while BPA has indicated a plan to join in 2028. The post-2028 contract is anticipated to include credits for capacity resources owned by customers, effectively reducing the cost of owning energy storage. These capacity credits are modeled in the IRP. Stand-alone lithium-ion batteries are the most common new dispatchable resources being installed across the utility industry and are a well-developed technology. For the IRP, new lithium-ion batteries are modeled inside Snohomish County, not paired with any specific renewable generation project. Each unit is modeled as a 25MW/100MWh based on the existing PUD Arlington Battery Energy Storage System. WA State Bill 5445 adds regulatory compliance value to energy storage if it is built on existing utility infrastructure and these benefits were included in the attributes for battery projects. The REC equivalents are based on the batteries ability to meet the PUD's annual peak load and its average annual load. Iron-air batteries are a new technology onto the market with very long duration and similar price to lithium-ion at the cost of project footprint and worse round-trip efficiency compared to lithium-ion. One unit was included for analysis of extended duration energy storage for demand reduction. Two configurations of local pumped hydro storage were considered with varying durations and output capability based on studies for a local pumped storage project within the PUD service territory. The PUD did not consider natural gas resources in the 2025 IRP as a viable long-term baseload or dispatchable resource. This choice is reflective of the Commission's stated Climate Change policy, increasing regulatory uncertainty around fossil fuel resources, and analysis that concludes that the PUD could procure lower cost supply-side resources through pursuit of storage or renewable resources. Natural gas plant pricing is provided as a price reference only for levelized energy and capacity price tables provided later in this section.

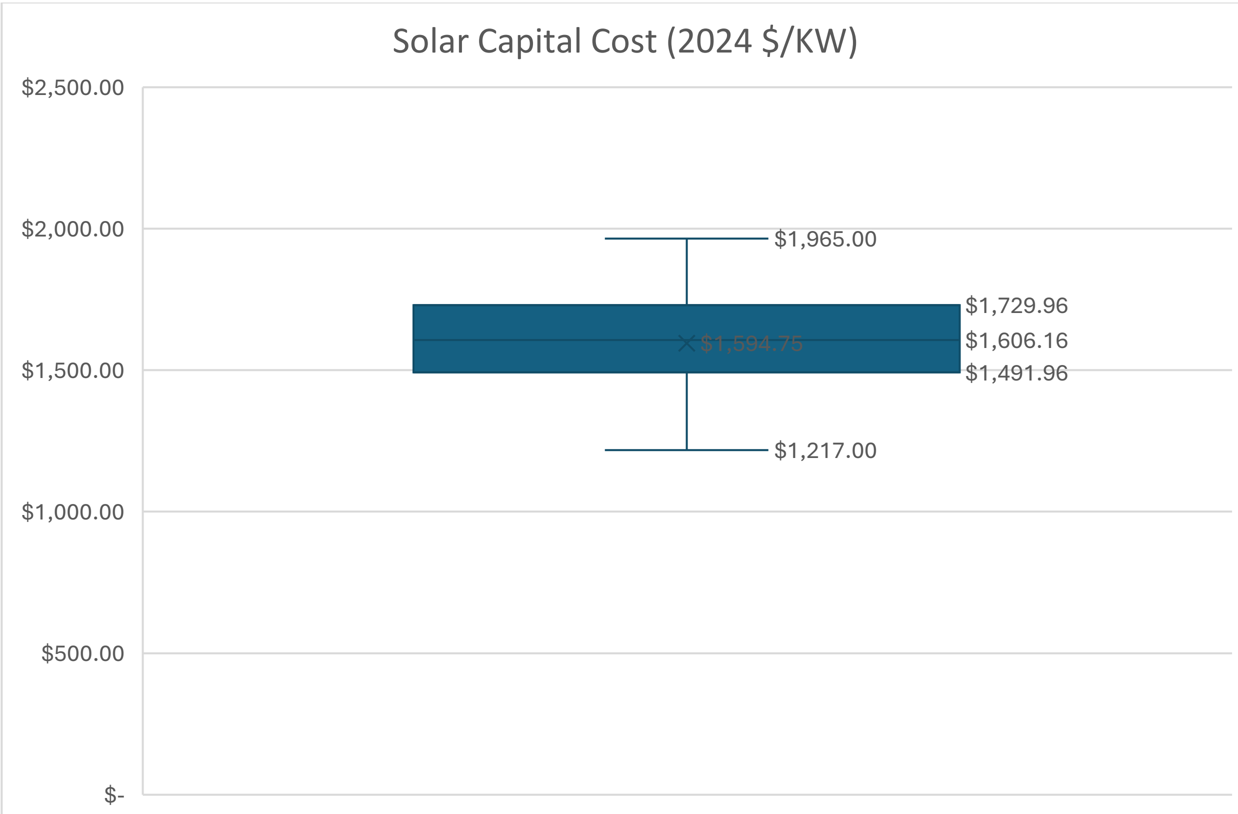
Table 5-6 Dispatchable Resource Options

Resource Type	Storage Duration	Nameplate MW	Units Available	First Year Available
Biodiesel Peaker	*	50	1	2026
Lithium-Ion Battery	4 Hr.	25	8	2029
Iron Air Battery	100 Hr.	25	1	2032
300MW Pumped Hydro Storage	8 Hr.	300	1	2035
150MW Pumped Hydro Storage	10.66 Hr.	150	1	2035
Simple Cycle Natural Gas Peaker	*	50	1	2026

Resource Costs

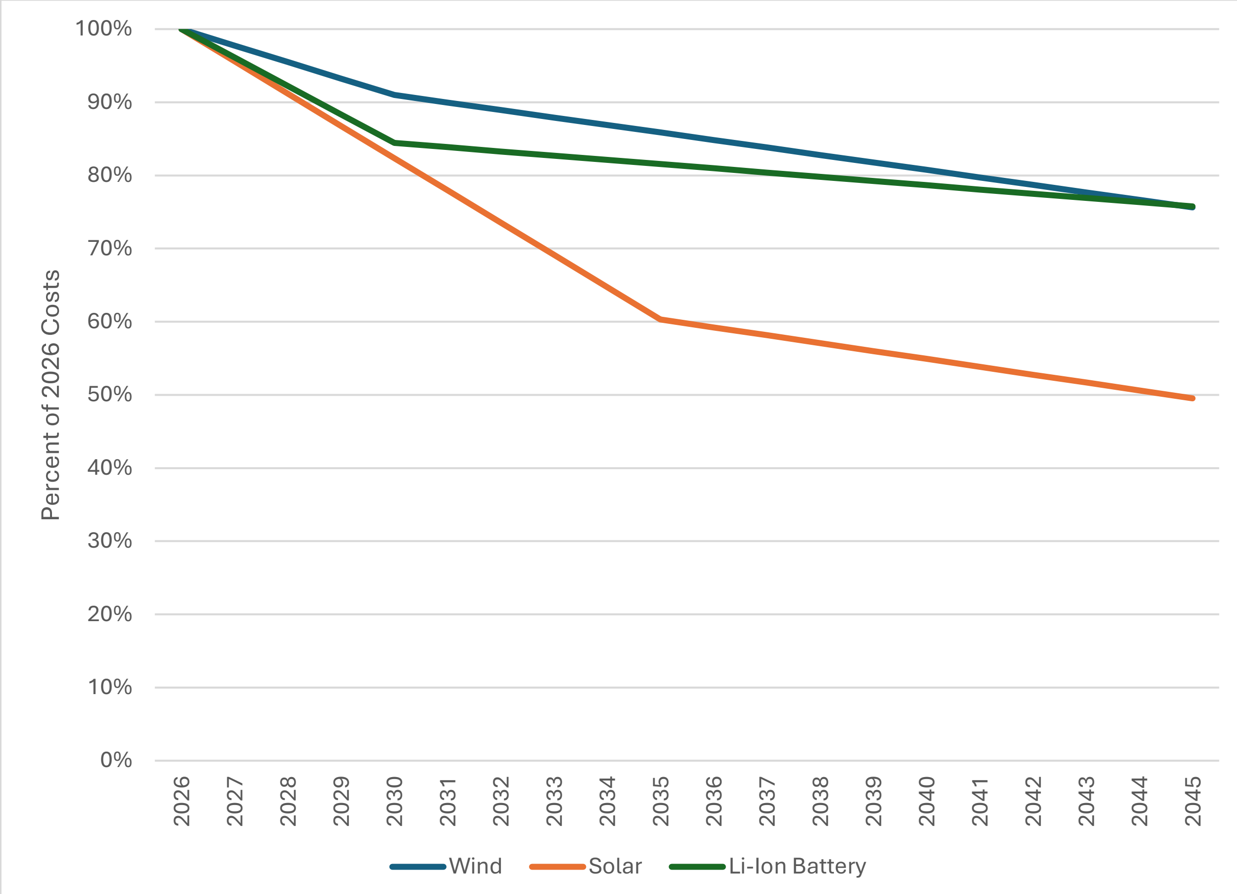
Supply-side resource costs in the 2025 IRP include the assessed total resource cost of developing and operating a resource. Operating costs include the cost of fuel (if applicable), the cost of resource support services if the resource is not delivered in flat annual energy blocks, and the cost of ancillary services that may be required to support the resource such as Variable Energy Resource Balancing Service (VERBS) through BPA as the PUD's balancing authority. All costs assume a discount rate of 4.5%, are in USD currency, and were converted to a 2024 dollar-year value. All federal tax credits such as the production tax credit and investment tax credit are included as the inflation reduction act and other incentives were at the time of writing. Changes to the tax incentive environment are covered in Section 3 Planning Environment. Cost estimates were made in each feasible delivery year for each resource type, such that the economic optimization model could draw upon present value cost estimates while considering PUD ownership of any given resource. The PUD's methodology for determining supply-side resource costs was derived by developing a composite of credible, third-party cost estimates for the Pacific Northwest region, and normalizing this value to the scale, dollar year, and cost methodology. Cost data was derived from other recent regional utility IRPs, the Northwest Renewable Energy Laboratory's (NREL) All-Technology Bulletins (ATB), and the NWPCC's 2021 Power Plan. The 2025 IRP considers the midpoint of a distribution of regional costs to be the composite cost used as an input for the base case scenarios. Low-cost scenarios use the bottom quartile and high-cost scenarios use the high quartile cost spreads as described in Section 4. Figure 5-27 below shows an example of how a composite cost was derived for the Overnight Cost of Capital (development cost estimate) for utility-scale solar plants.

Figure 5-27 Example Composite Overnight Capital Cost



For some resource types where the efficiency of a resource is expected to increase significantly, or costs are expected to decrease significantly, the 2025 IRP applies a modification to the effective cost-per-nameplate of the resource. These modifications are derived from the NREL's 2023 and 2024 Annual Technology Baseline data forecasts for cost and efficiency changes over time for resources available to the broader Seattle market. The purpose of this practice is to financially account for technology improvements over time, such that the economic value of resource deferral includes consideration of cost decreases or efficiency gains. Cost modifications are made lithium-ion batteries, utility scale solar, and utility scale wind resources to reflect forecasted technology improvements.

Figure 5-28 Overnight Capital Cost Projections from Technological and Efficiency Improvements



Resource Support Services

When the PUD changed to the Load-Following product, resources that are used to serve above high-water mark load must be delivered in flat annual energy, per the BPA Regional Dialogue Guidebook[15] and the Tier Rates Methodology (TRM). Resources may be flattened and shaped with either BPA supplied resource support services (RSS) or must be supplied externally to deliver the resource in flat annual blocks. BPA offers a suite of services under the RSS umbrella including Diurnal Flattening Service (DFS), Forced Outage Reserve Service (FORS), Secondary Crediting Service (SCS), Resource Remarketing Service (RRS), and Transmission Curtailment Management Service (TCMS). RSS enables BPA to cover the costs of following the variation between planned and actual resource amounts and to account for the impact that resource shapes and fluctuations have on BPA's cost to meet its other customer load. The costs for RSS are applied to each variable resource option including Run-

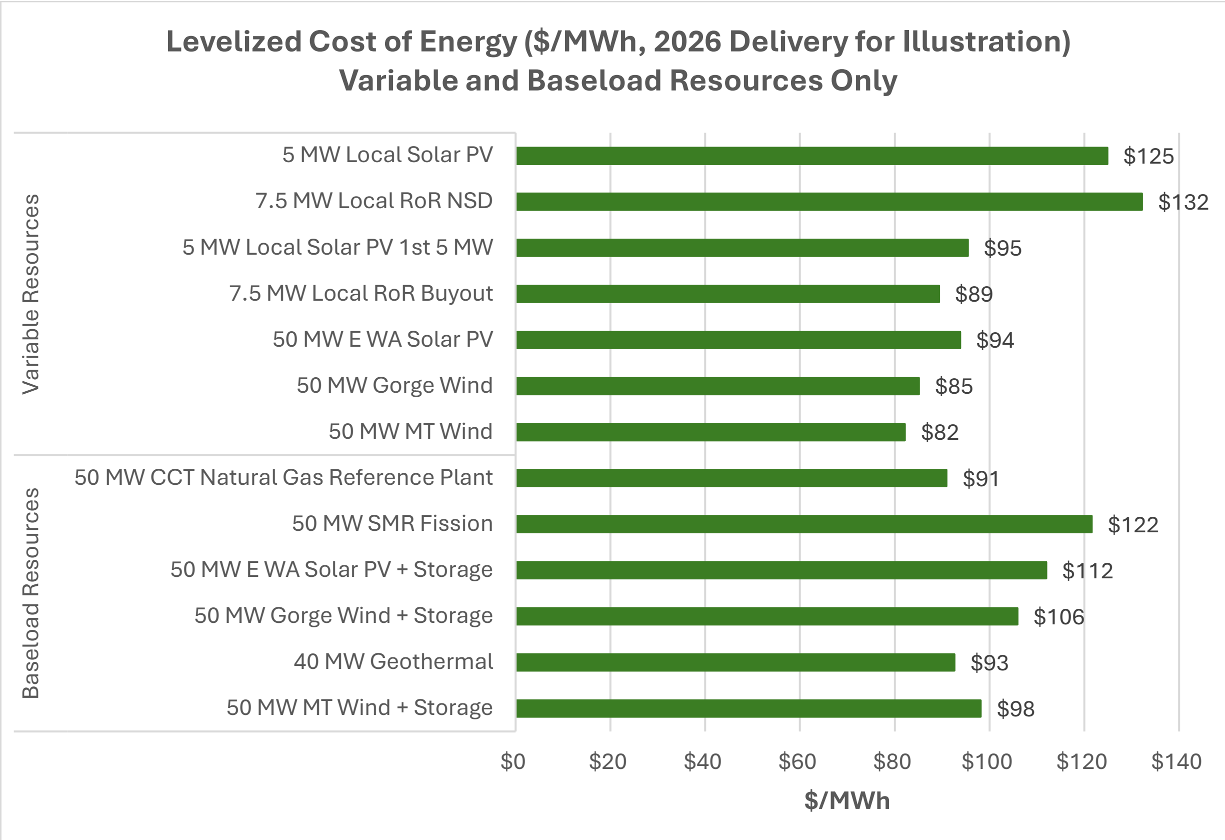
[15] Regional Dialogue Guidebook: Background on Products, Rates, and Resource Support Services available to BPA's Public Utilities

of-River Hydro, Solar, Wind and Renewables plus Storage. Planning RSS costs necessarily makes assumptions on actual generation given the cost is based on the variation between planned and actuals. The PUD used the BP-26 rate case RSS model provided by BPA to estimate average RSS costs based on an assumed generation profile and generated a $/MWh price for each type of resource. For variable renewable projects with storage, variability and output will better match planned output leading to a lower RSS cost, so the PUD added a 33% discount to RSS costs for renewable plus storage projects. Baseload resources such as nuclear and fusion have flat energy profiles and do not carry RSS costs. Energy storage such as batteries or pumped storage hydro are not considered generating assets and are not used to serve load, therefore don't have RSS costs. RSS costs are inflated over time in line with other BPA costs. RSS costs did not vary by scenario or sensitivity and were fixed across resource cost trajectories used. The effect of RSS on resource attributes is to eliminate variability and provide a planned output regardless of weather conditions. RSS also provides certainty to remarket excess generation if there is insufficient above-high-water mark load to serve at the BPA remarketing rate.

Levelized Cost of Energy

Levelized cost of energy represents a measure of the net present value of the energy production of a given resource over its lifetime. To fairly compare different types of resources, costs are normalized to 2026 even though most resources have earliest available dates in the future. A comparison of the Levelized Cost of Energy across Baseload and Variable Supply-Side Resources is provided in Figure 5-29 Variable energy sources have the lowest levelized cost of energy due to low capital and operational costs. Baseload resources have higher levelized cost of energy than variable resources owing to their higher capital costs associated with paired storage or higher capital costs. Only resources with readily available pricing information are compared.

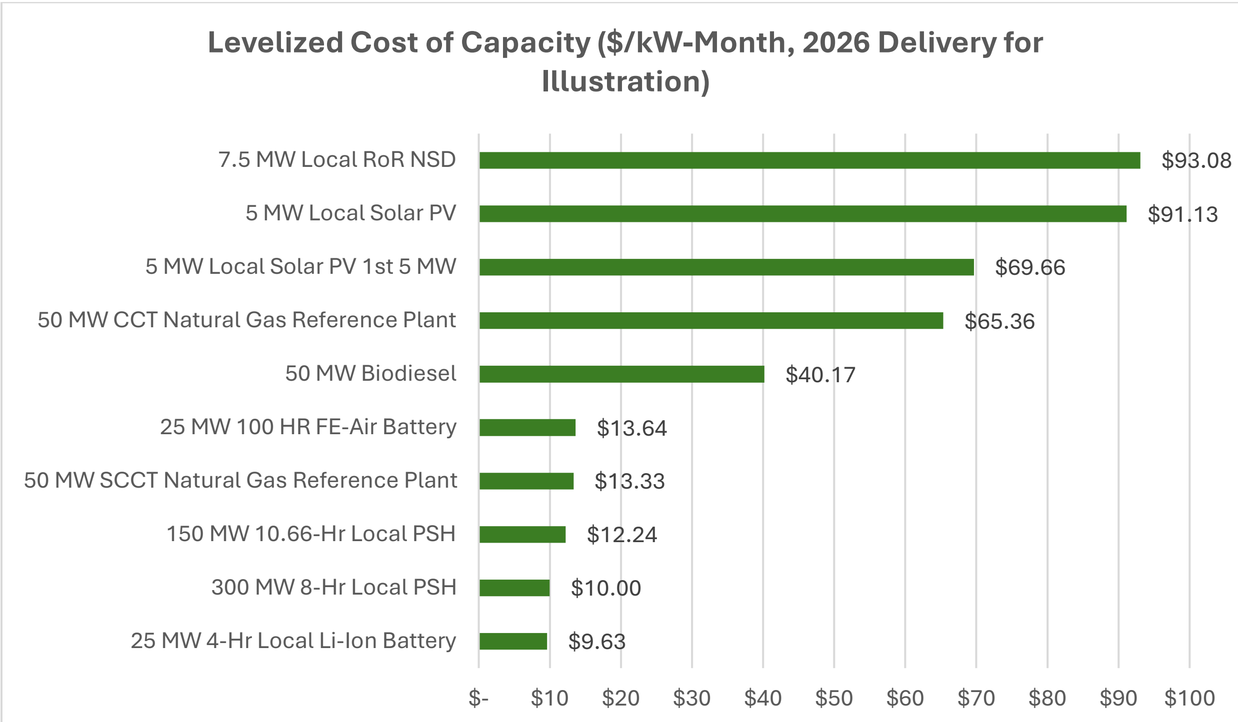
Figure 5-29 Levelized Cost of Energy, 2026 Delivery



Levelized Cost of Capacity

Levelized cost of capacity normalizes the total cost of a resource's ability to dispatch or provide energy in the monthly peak hour across all years in the study period. This metric provides the cost of a resource to provide peak reduction the project lifetime. A comparison of the Levelized Cost of Capacity (LCOC) across supply-side resource options that reduce peak demand is provided in Figure 5-30. Generation resources within the PUD service territory are given demand credit based on the WRAP methodology for capacity contribution and the BPA Provider-of-Choice framework for billing credits. Storage resources offer a very low levelized cost of capacity while energy resources in the service territory offer very little peak demand contributions based on the WRAP methodology. Resources outside the PUD service territory do not have peak demand reduction attributes and are not included here.

Figure 5-30 Levelized Cost of Capacity 2026 Delivery



Emissions

Carbon content is primarily treated financially in the 2025 IRP, consistent with the CETA requirement to incorporate the Societal Cost of Carbon (SCC) for direct or indirect emissions. This embedded cost is attributable to all resources that use the wholesale market as a fuel, as the PUD is not considering adding any fossil fuel resources to its portfolio. Only BPA's Tier 1 and Short-Term Tier 2 products (discussed in the next section), include indirect wholesale market exposure. To capture generic carbon estimates in metric tons of CO2 equivalent for comparative use for resource evaluation, simplifying assumptions were made. These assumptions presume that the 0.437 CO2 equivalent metric found in state law for Fuel Mix Disclosure purposes is an appropriate estimate of wholesale market emissions on average.

BPA Tier 2

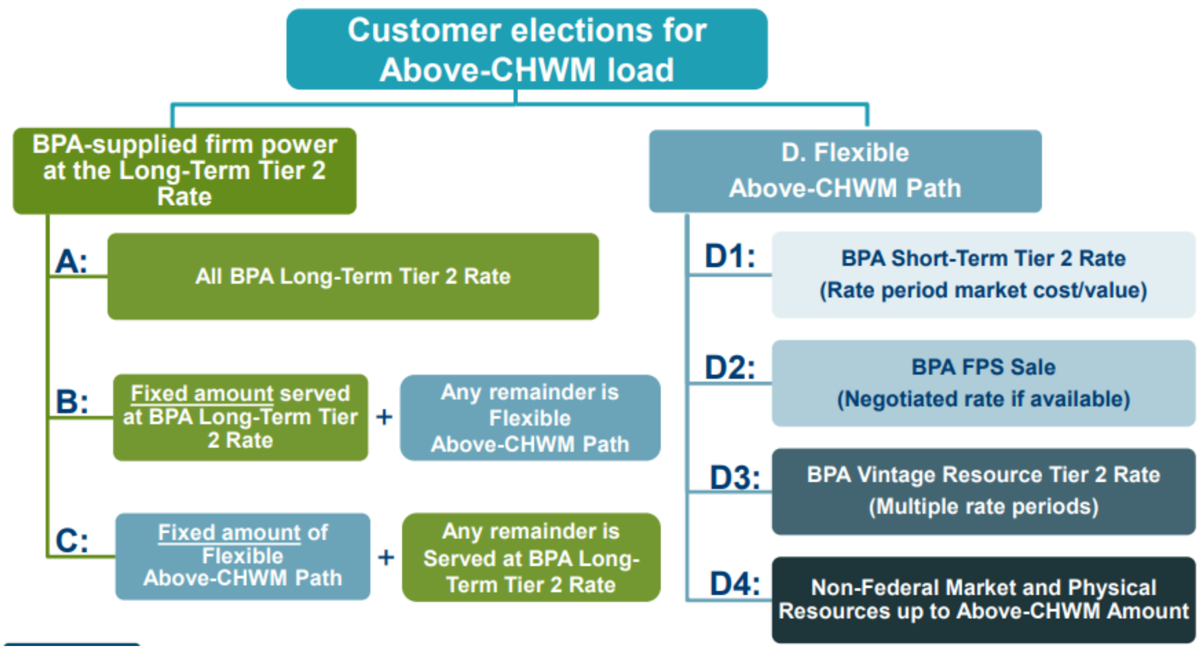
A core question of this IRP is the Tier 2 election the PUD will make in early 2026. Tier 2 serves above-high-water mark load and comes in two primary varieties: Short-Term and Long-Term.

Short-Term Tier 2 consists of a market price indexed product assumed to be sourced by BPA from the Wholesale market. Long-term Tier 2 is based on the BPA resource plan, which includes significant market purchases and solar procurement in the later period. The IRP models long-term Tier 2 as always starting with 100% market purchased energy and layering in solar until it is a 50/50 mix of market energy and solar for the base case market environment. Market price expectations change BPA's resource plan substantially and therefore, the IRP's long-term Tier 2 model adjusts its market to physical resource mix depending on market prices. In a high market price environment long-term Tier 2 is modeled to add physical resources until long-term is 75% solar. In contrast a low-price environment will have less incentive to add physical resources, leading to a 75/25 market to physical mix.

The 2025 IRP informs a default strategy the PUD will use as it learns additional details of Tier 2 service from BPA in 2026. The choice of Long-term or Short-term Tier 2 first will inform future resource decisions while offering tradeoffs between them. Electing long-term Tier 2 first gives the PUD product certainty for serving future load growth up to its elected amount, removes delivery risk of supply side resources and leverages BPA's large purchasing power for new physically backed resources if they are acquired. Long-term Tier 2 cannot be displaced once it has been delivered like short-term Tier 2 potentially reducing flexibility however costs for long-term Tier 2 delivery are only for power delivered. Short-term Tier 2 power is determined on a rate period by rate period basis. Costs and quantity to be delivered are both determined through the rate case process and are subject to rate changes. The PUDs short term Tier 2 take can be offset or reduced with new supply side resource acquisitions giving the PUD optionality and flexibility in meeting regulatory compliance. The BPA Post-2028 contract includes a one-time option to reduce the election of undelivered long-term Tier 2. The PUD will choose which pathway to take and its fixed amount of first choice to create a comprehensive strategy for long term load service. The pathway option is described below. The flexible Above-CHWM path includes excess FPS sales and vintage rates that are not considered for the IRP analysis. Neither of these options can be expected to be used for a planning study, may not be available when required and may not have the attributes required for load service. These will be evaluated on a case-by-case basis when they are offered but are not included here. On the other side of the flowchart long-term Tier 2 can either supply all load growth, serve up to an elected amount of load growth, or serve load after an elected amount of short-term Tier 2 is exhausted.

Both BPA Tier 2 products are at least partially market based and market prices include the societal cost of carbon in the dispatch price. Load service through either Tier 2 product will include the societal cost of carbon proportionate to the emissions of energy sourced from an unspecified source for the market portions of long-term and the entirety of short-term Tier 2. Figure 5-31 below illustrates the election options and the Tier 2 products as described by BPA. Short-term Tier 2 products are shown in blue, long-term Tier 2 are indicated by green. BPA FPS Sale and BPA Vintage Resource Tier 2 Rate are on an “as available” basis and not always available on a planning basis so are not considered for long-term resource planning. If these are offered during any given rate period the cost and benefits would be evaluated at that time for resource fit and cost. On the long-term Tier 2 pathway the volume needed to fully supply the PUD's long term load growth needs is known and may be elected for the first portion of either option B or option C meaning that option B can be thought of as entirely long-term or some portion of load service at long term rates, making option A the less flexible pathway. Therefore, the decision reduces to either option B or option C with an appropriate volume election for flexibility.

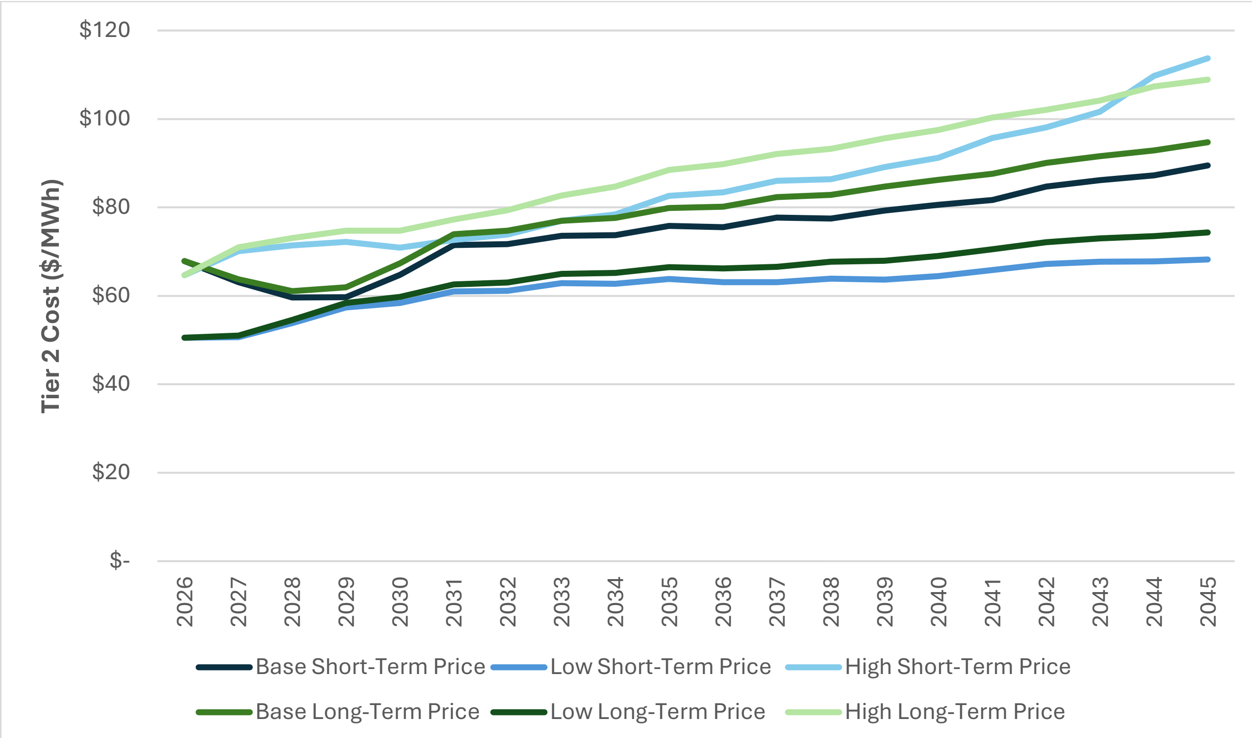
Figure 5-31 Tier 2 Election Path Options



Tier 2 Costs

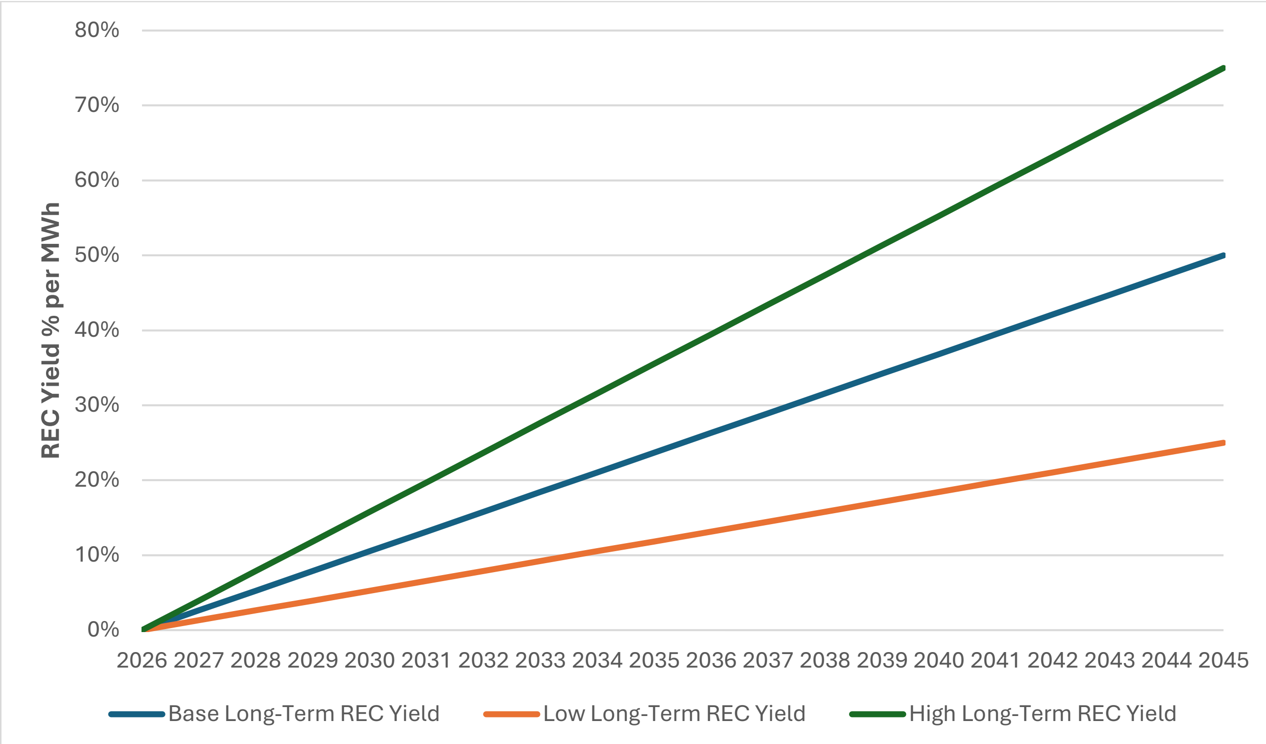
The IRP considers Tier 2 for its regulatory compliance and cost characteristics compared to other supply- or demand-side resources. These costs are shown for both long-term and short-term Tier 2 products below. The assumptions of long-term environmental attributes are described above and are not considered in the costs for long-term Tier 2 separately. The costs for short-term Tier 2 are based on the wholesale market price forecast with an expected high market price increase plus a capacity price. This blended price forecast is based on BPA's BP-26 rate book to align market prices with BPA's updated pricing methodology. Two additional price traces were created from the base price for high and low Tier 2 cost scenarios and sensitivities.

Figure 5-32 Tier 2 Price Forecast ($/MWh)



Long-term Tier 2 is proportionally based on physical renewable resources that bear RECs as shown in Figure 5-33 on a MWh basis. Higher market prices lead to more physical resources, displacing market supply leading to a higher REC yield and vice versa for low price environments. Over time the proportion of physical resources grows in line with BPA's current resource program.

Figure 5-33 Long-Term Tier 2 Forecast REC Yield



Transmission

The PUD uses the Network Transmission product to facilitate delivery of its Load-Following product to serve load in its service territory. The NT product is a metered product based around the demand the PUD places on the regional BPA transmission system at the time of BPAs highest monthly usage. The PUD expects to utilize NT transmission for all of its load service.

The PUD continues to maintain some Point-to-Point (PTP) pathways to facilitate transactions beyond load service such as surplus resource marketing. Because the NT product can only be used to serve load, PTP is necessary for the export of power or market transactions.

NT transmission billing determinants are strictly associated with the amount of NT capacity utilized by the PUD during BPA's peak usage hour. This has several implications for resources and their impacts on the PUDs transmission costs. Under PTP, resources sited within the PUDs service territory lowered transmission costs as PTP was not required to deliver those resources to the PUDs system. Under NT however, whether a resource is within the PUDs service territory or is external will not impact the cost of the NT product.

While resources outside the service territory do not incur additional transmission costs to serve load, if a new resource is sited and the transmission paths required to deliver it to the

PUD are constrained or do not have available firm capacity, that resource will be delivered on “non-firm” transmission. Non-firm transmission increases the risk of curtailment in the event congestion occurs and limitations are required; however, BPA provides NT Redispatch to ensure that dedicated loads are served which comes with a redispatch cost. This protection makes the risk associated with non-firm transmission financial rather than incurring delivery or reliability risk.

NT costs are calculated for forecast peak needs including the effects of conservation, demand response and appropriate supply-side resources. Ancillary balancing services (VERBS) are required by BPA as the PUD’s balancing authority to ensure frequency standards are maintained and these costs are included for the appropriate resources.

Summary

The analytic framework the IRP uses to find least-cost, lowest-risk pathway to serve energy, capacity, and regulatory needs. Using a combination of demand-side, supply-side, and BPA Tier 2 options provides a robust set of resource choices to meet the needs of the PUD from 2026 to 2045. All resources are compared on an equal footing using established methodologies from outside subject matter experts as well as PUD analysis of available technologies and BPA Tier 2 options to appropriately benchmark all resources for fair comparison. The BPA power contracts provide the structure defining the cost and benefits under the Load-Following benefits for all programs while regulatory compliance is a key driver of resource decisions. The result of each scenario and sensitivity is an optimal portfolio selection, and these are provided below in Section 6.

6 Portfolio Results

The development, use case, and detailed descriptions of the 2025 IRP scenarios and sensitivities are contained in Section 4 and provide varying environments to develop least-cost, least-risk portfolios. The scenarios and sensitivities are as follows.

Scenarios:

1. Base Case
2. Low Growth Case
3. High Growth Case
4. High Technology Case
5. Limited Renewable Project Availability Case

Sensitivities:

1. High BPA Costs
2. Low BPA Costs
3. Shallow Renewable Energy Credit Market
4. CETA Only Policy Environment

Note that all optimization scenarios and sensitivities include base assumptions and forecasts that include the effects of climate change, societal cost of carbon emissions (per CETA), electrification (including electric vehicles), market energy prices, load growth, and resource attributes and costs.

In addition to demand-side resources, these nine portfolios were evaluated with a broad range of renewable and nonrenewable resources required by state rules for IRP planning,[16] which informed the selection of a preferred Long-Term Resource Strategy. The Long-Term Resource Strategy represents the most effective mix of demand and supply-side resources that consider supply availability, energy-related regulatory policies, resource costs and other uncertainties.

Portfolio Development

The process used to construct the final portfolio output for each case is nearly identical. The differences in the process are entirely related to the unique model inputs for each case as described in Section 4. Based on these inputs, an in-house optimization model simultaneously identifies the optimal mix of conservation and energy efficiency measures,

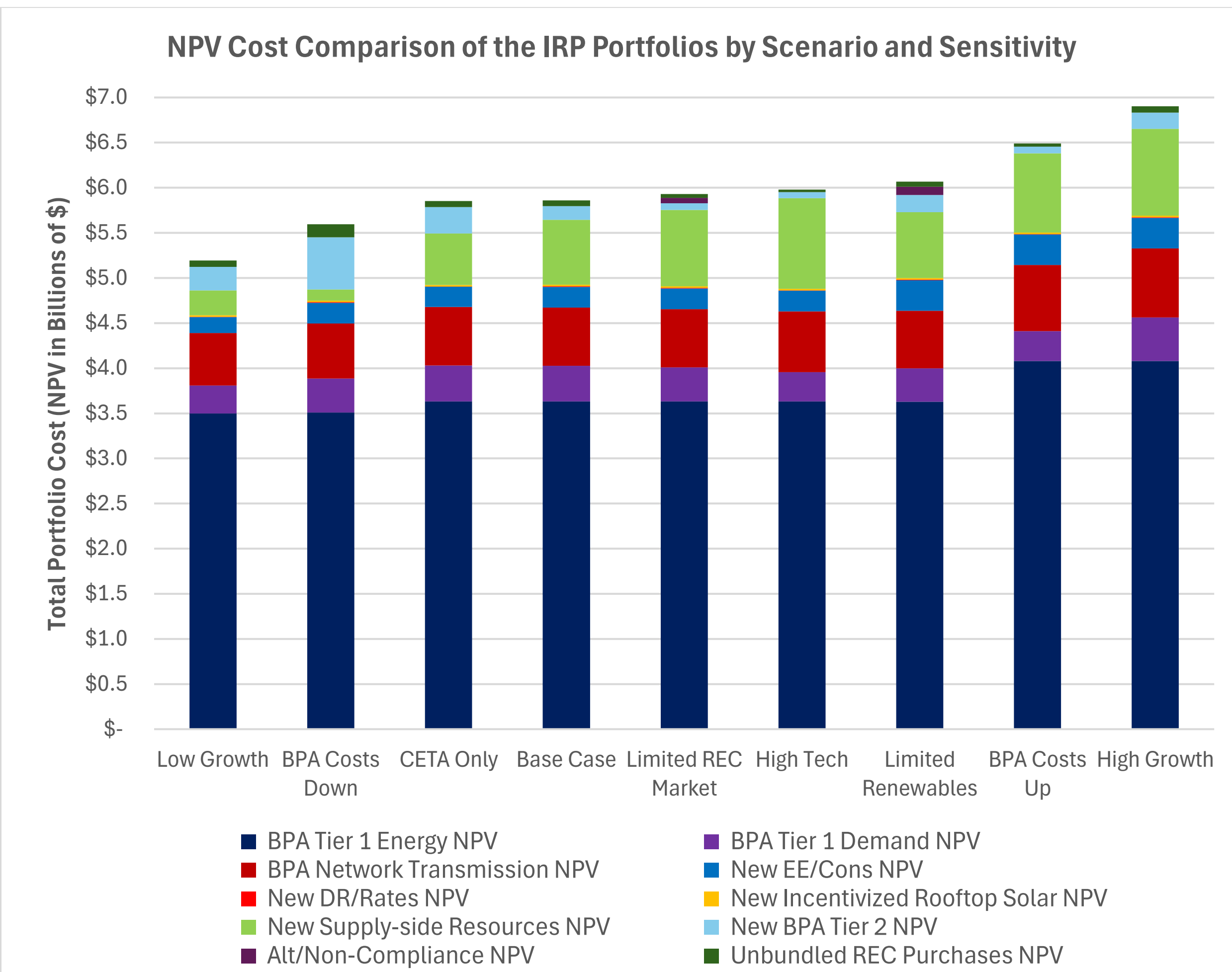
[16] Referenced requirements are detailed in the Revised Code of Washington, Section 19.280.030.

demand response measures, new rate programs, supply-side resources, BPA Tier 2 service, and unbundled REC options to solve for load service and regulatory compliance.

The in-house portfolio optimization model identifies the incremental costs and benefits associated with each candidate portfolio. Portfolio costs are measured as the net present value (NPV) of the incremental cost of new resource additions to the portfolio over the 2026 through 2045 study period. Net portfolio costs include fuel costs, cost of carbon emissions from supply-side resources where applicable, demand side costs and REC market purchases.

Figure 6-1 below illustrates the net present values (NPVs) of the total portfolio costs by scenario or sensitivity over the 20-year study period. The stacked bars represent the total portfolio cost NPV for BPA Tier 1 energy, demand, network transmission, incremental demand side investments, supply-side resource additions, and new REC additions for each scenario and sensitivity.

Figure 6-1 Portfolio NPV by Scenario and Sensitivity and Resource Type



Portfolio Findings

Several general trends and insights emerged in the development of the portfolios:

1. Energy efficiency and conservation are cost-effective in all scenarios and sensitivities. Demand side resource investments play a significant role in the long-term resource strategy.

2. Utility-scale renewable energy resources are the primary supply-side additions across scenarios and sensitivities for load service and regulatory compliance. BPA Short-Term Tier 2 energy acts as the bridge between new resource additions.

3. In all scenarios and sensitivities, demand response and rates programs are cost-effective to mitigate demand charges from BPA and help to meet compliance targets with the Energy Independence Act.

4. Some but not all portfolios include locally sited battery energy storage additions depending on the input variables. These additions can lower the BPA Demand Charge as well as help meet regulatory compliance targets with the Energy Independence Act.

5. Locally sited solar under 5 MW and some customer-owned solar programs for large systems greater than 50 kW are cost-effective across portfolios.

6. Significant amounts of unbundled REC purchases are required annually in all scenarios and sensitivities to meet regulatory compliance targets.

7. All portfolios are fully compliant with the Energy Independence Act and the Clean Energy Transformation Act throughout all years of the IRP study period.

These findings and other key insights along with the long-term resource plan and action plan are explored in Section 7 of this document.

Portfolio Results

The final candidate portfolio for each case represents the lowest reasonable cost combination of resources that meets regulatory and load growth needs given the scenario.

Table 6-1 summarizes the resource additions for the nine scenarios and sensitivities:

Table 6-1 Summary of Total Portfolio Resource Additions by Case

Case Portfolios	BPA Long-Term Tier 2 (aMW)	EE/Cons (aMW)	Battery Energy Storage (MW)	Locally Sited Solar (MW)	Utility-scale Solar (MW)	Utility-scale Wind (MW)	Other Clean Energy Resources (MW)	DR/Rates (Peak MW)	Large Rooftop Solar Incentive (aMW)
Base	0	129.16	-	10	**0**	**500**	50	65.56	2.70
Low	0	118.91	50	10	**0**	**100**	50	65.56	2.70
High	0	150.06	-	10	**250**	**500**	50	65.56	2.70
High Tech	0	129.16	200	10	**250**	**500**	100	65.56	2.70
Limited Renewables	0	150.06	25	10	**150**	**300**	50	66.64	2.70
High BPA Costs	0	150.06	200	10	**200**	**450**	50	65.56	2.70
Low BPA Costs	0	129.16	0	10	**0**	**200**	50	66.64	2.70
Shallow Rec Market	0	129.16	25	10	**200**	**500**	50	66.64	2.70
CETA Only Policy	0	129.16	0	10	**0**	**250**	50	60.63	2.70

The following section details the portfolios by case showing the total resource additions from 2026 through 2045:

Base Case

Figure 6-2 and Figure 6-3 below detail portfolio resource additions in the Base Case scenario added over time to serve load growth, reduce or shift peak load, and/or meet regulatory compliance obligations. Annual compliance obligations that are in excess of new physical resource acquisitions are met by a limited and controlled amount of unbundled REC purchases which are not shown in the resource addition figures.

Figure 6-2 Base Case Energy Resource Additions

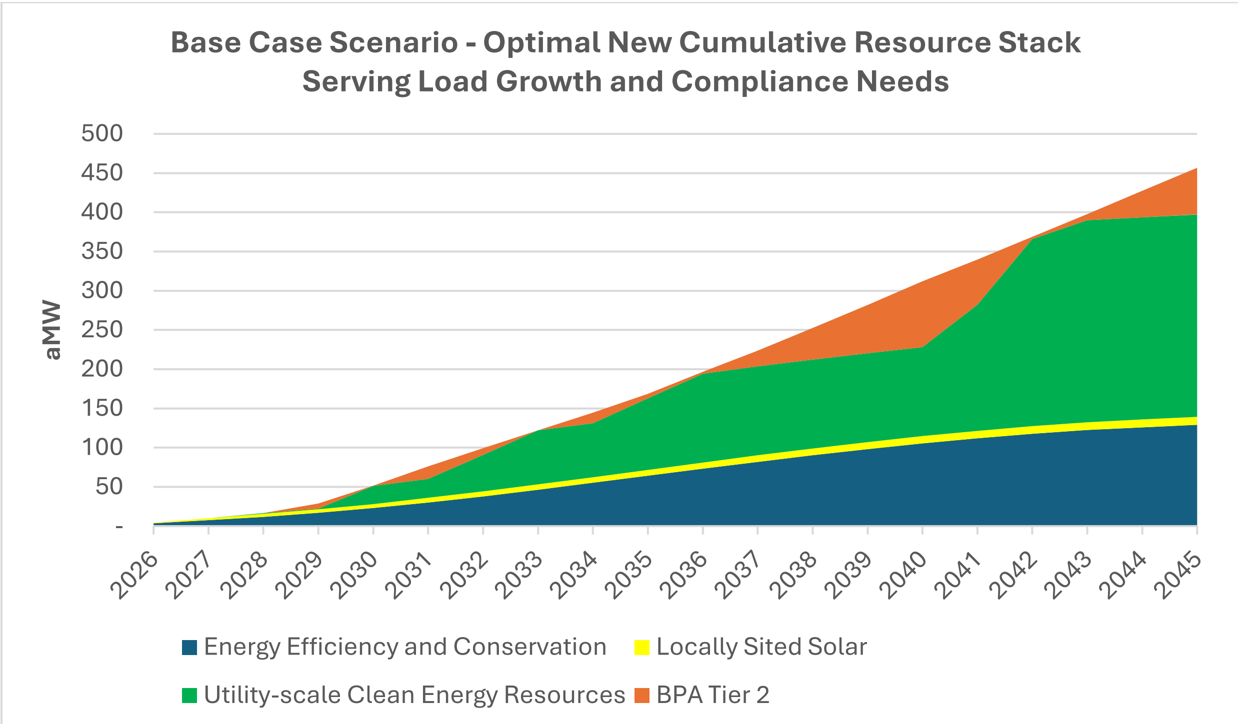
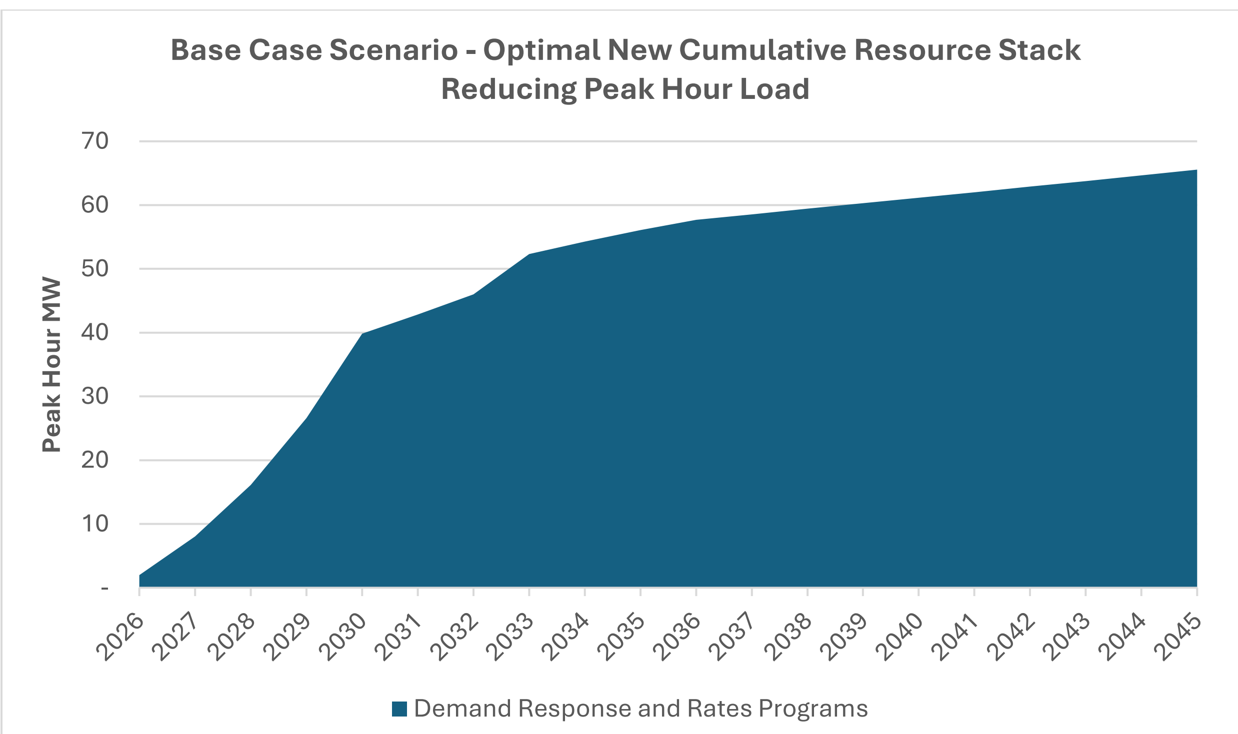


Figure 6-3 Base Case Peak Demand Resource Additions



Low Growth Case

Figure 6-4 and Figure 6-5 below show the optimal resource additions selected to meet the needs of the Low Growth scenario. While the general mix of resource additions is similar to the Base Case, the total amount of new resource additions is lower due to the lower load growth forecast assumptions built into this scenario. This lower load growth also reduces the ultimate regulatory compliance obligation targets, thus requiring fewer utility-scale clean energy resources. In this scenario, locally sited battery energy storage is part of the optimal resource stack due to the lower capital cost assumptions built into this scenario.

Figure 6-4 Low Growth Case Energy Resource Additions

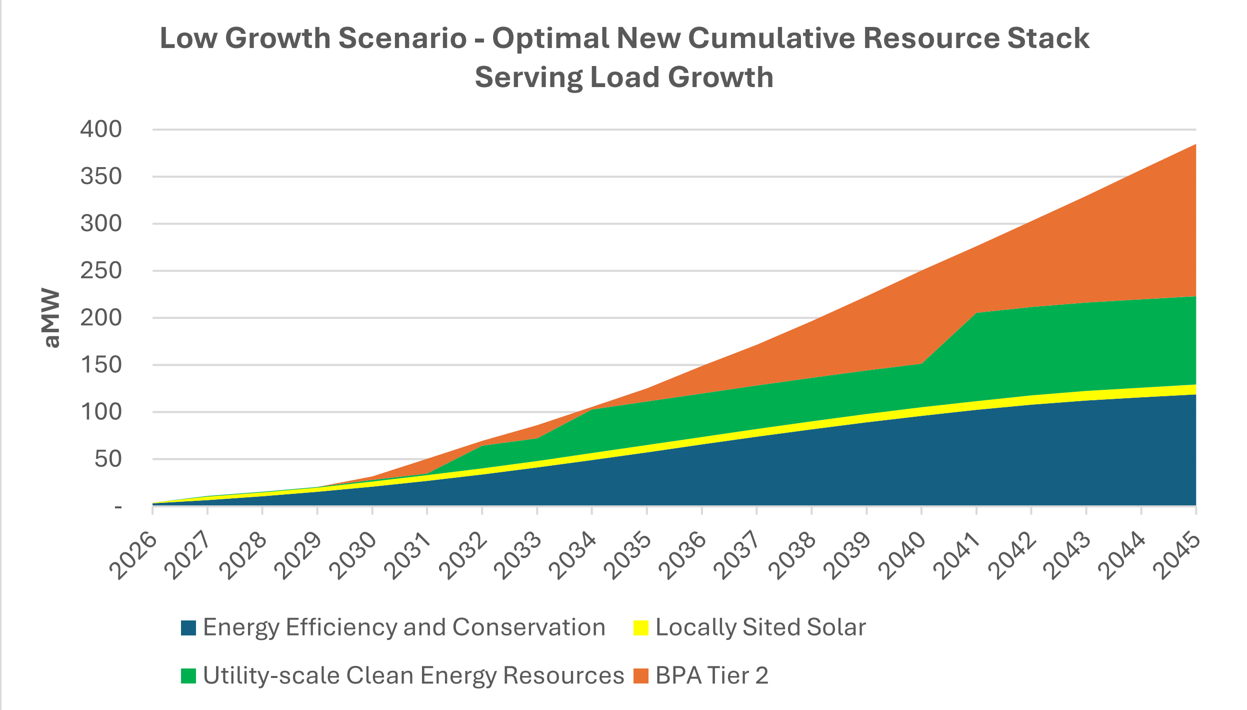
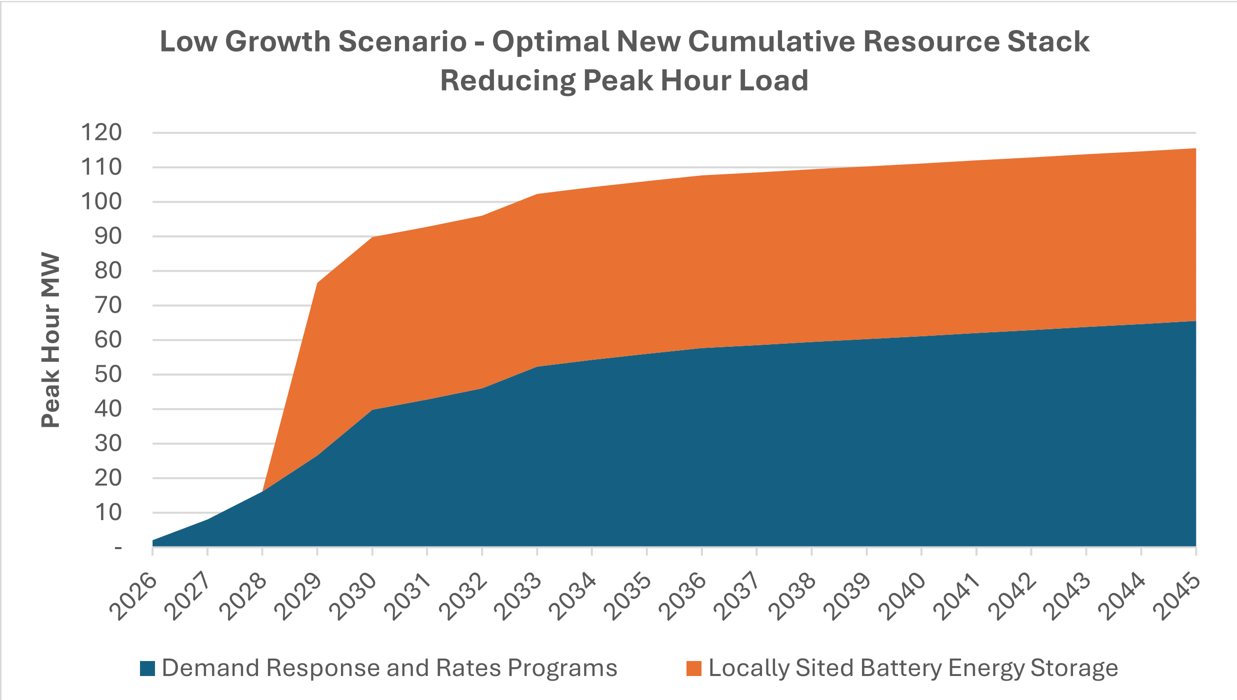


Figure 6-5 Low Growth Case Peak Demand Resource Additions



High Growth Case

Figure 6-6 and Figure 6-7 below show the new resource additions for the High Growth scenario. In this scenario, load growth is significantly higher than in the Base Case scenario. Regulatory compliance obligation targets are higher, thus more utility-scale clean energy resources are needed to meet these targets and serve load growth. In this scenario, locally sited battery energy storage is not selected due to the increased capital cost assumptions built into this scenario.

Figure 6-6 High Growth Case Energy Resource Additions

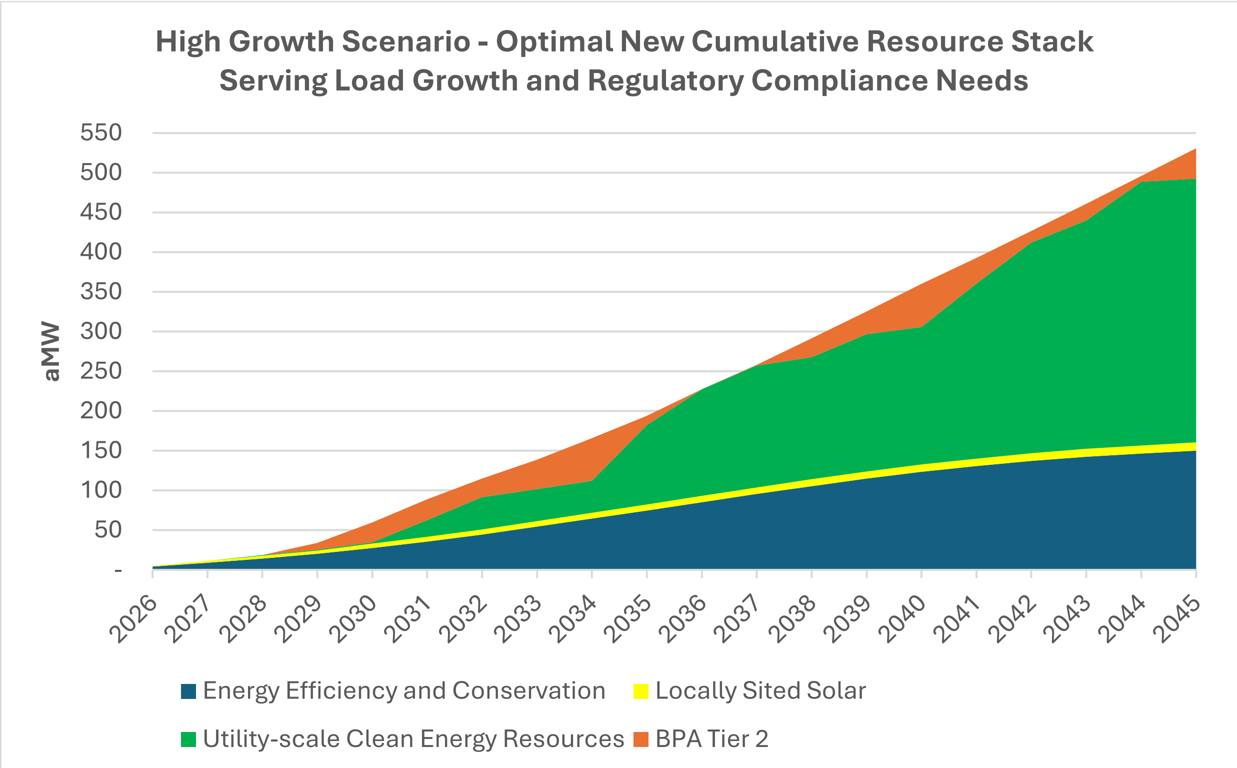
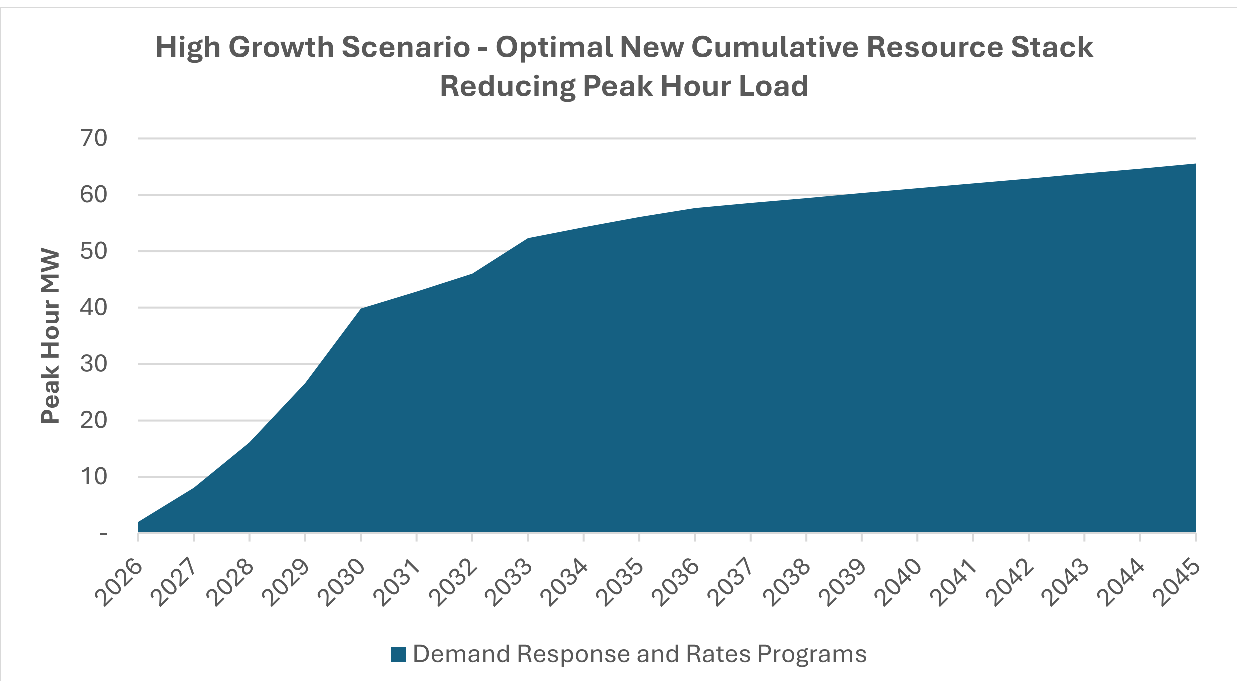


Figure 6-7 High Growth Case Peak Demand Resource Additions



High Technology Case

Figure 6-8 and Figure 6-9 below show the new resource additions for the High Technology scenario. In this scenario, utility-scale clean energy resources and batteries are selected in large quantities due to their relative decrease in capital cost assumptions and relative increase in scalability and ease of procurement.

Figure 6-8 High Technology Case Energy Resource Additions

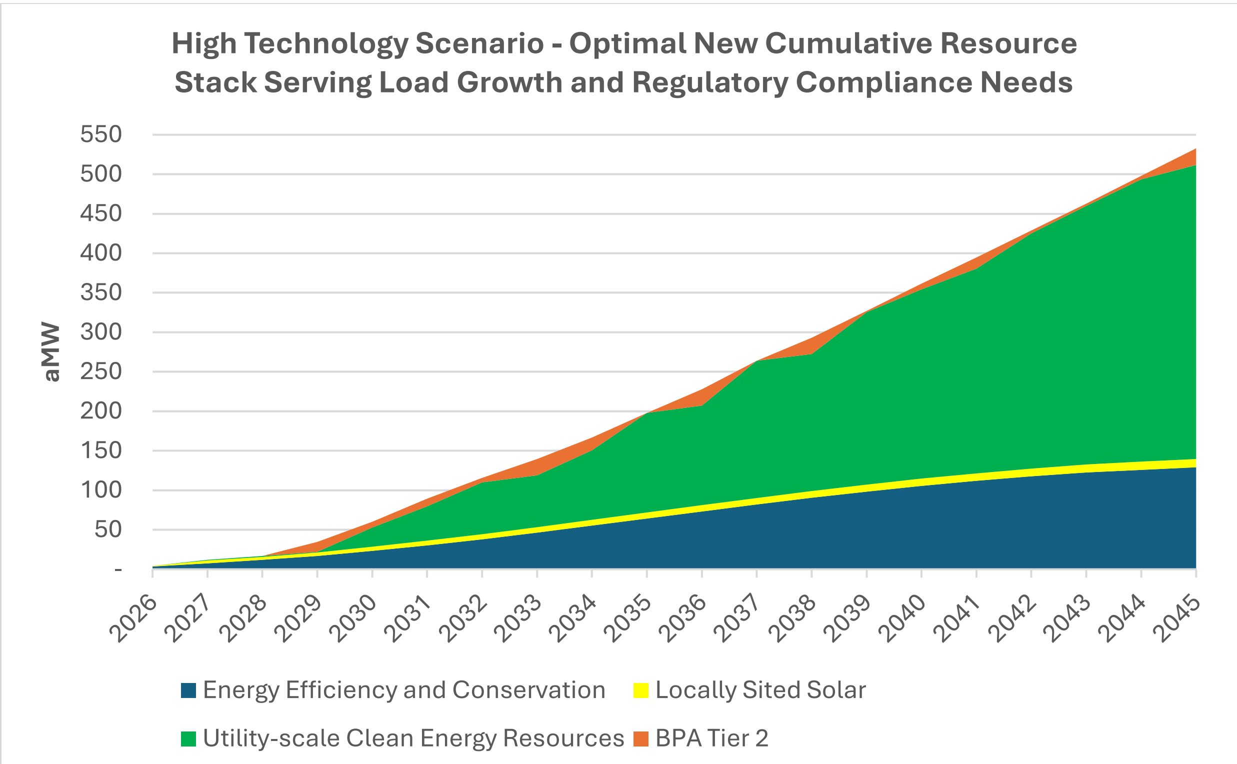
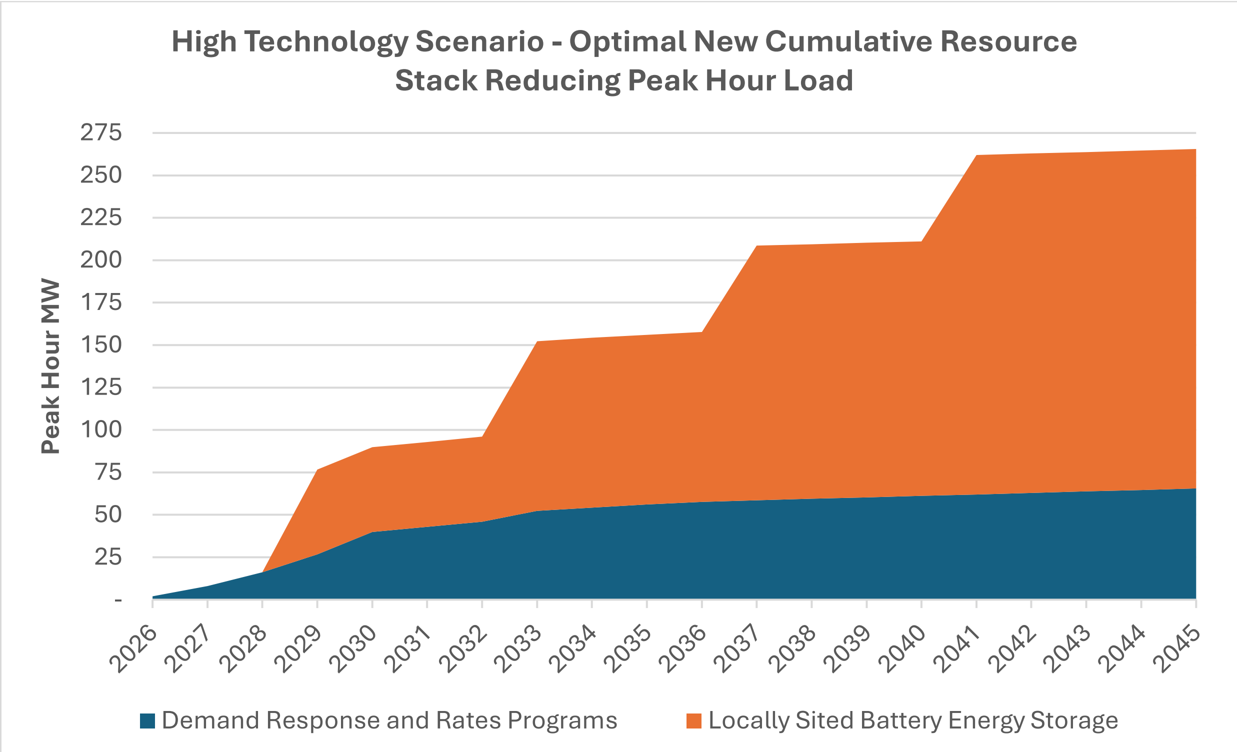


Figure 6-9 High Technology Case Peak Demand Resource Additions



Limited Regional Renewables Case

Figures 6-11 and 6-12 show the new resource additions for the Limited Renewables scenario. Resource additions in this scenario are not largely different than in other scenarios in terms of resource types, however the development of these renewable resources is delayed. Meeting compliance targets in this scenario is costly and difficult and increases reliance on unbundled REC purchases in a constrained REC market. With fewer regional renewable energy resources developed later in the study period the REC market is constrained and REC prices are higher, leading to higher compliance costs. Energy storage is developed in this case for its regulatory compliance attributes to offset higher REC prices.

Figure 6-10 Limited Renewables Case Energy Resource Additions

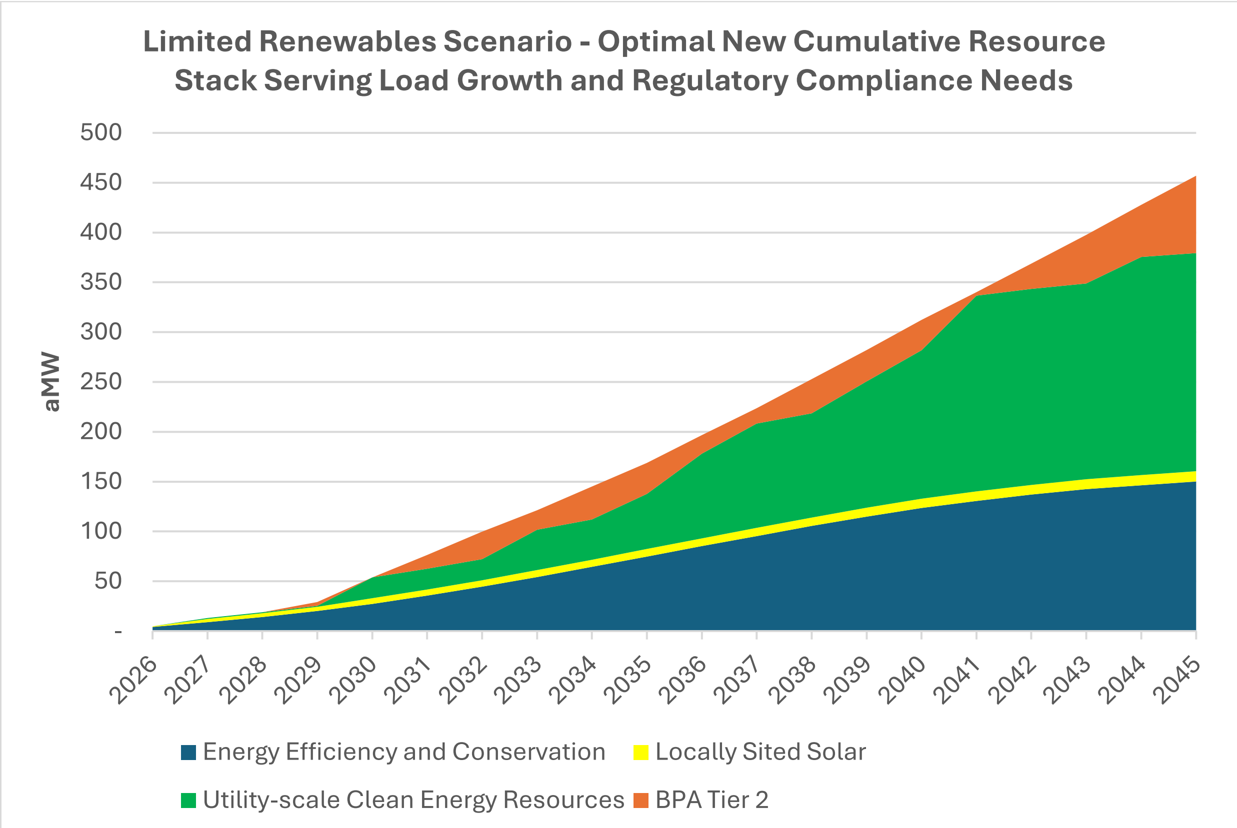
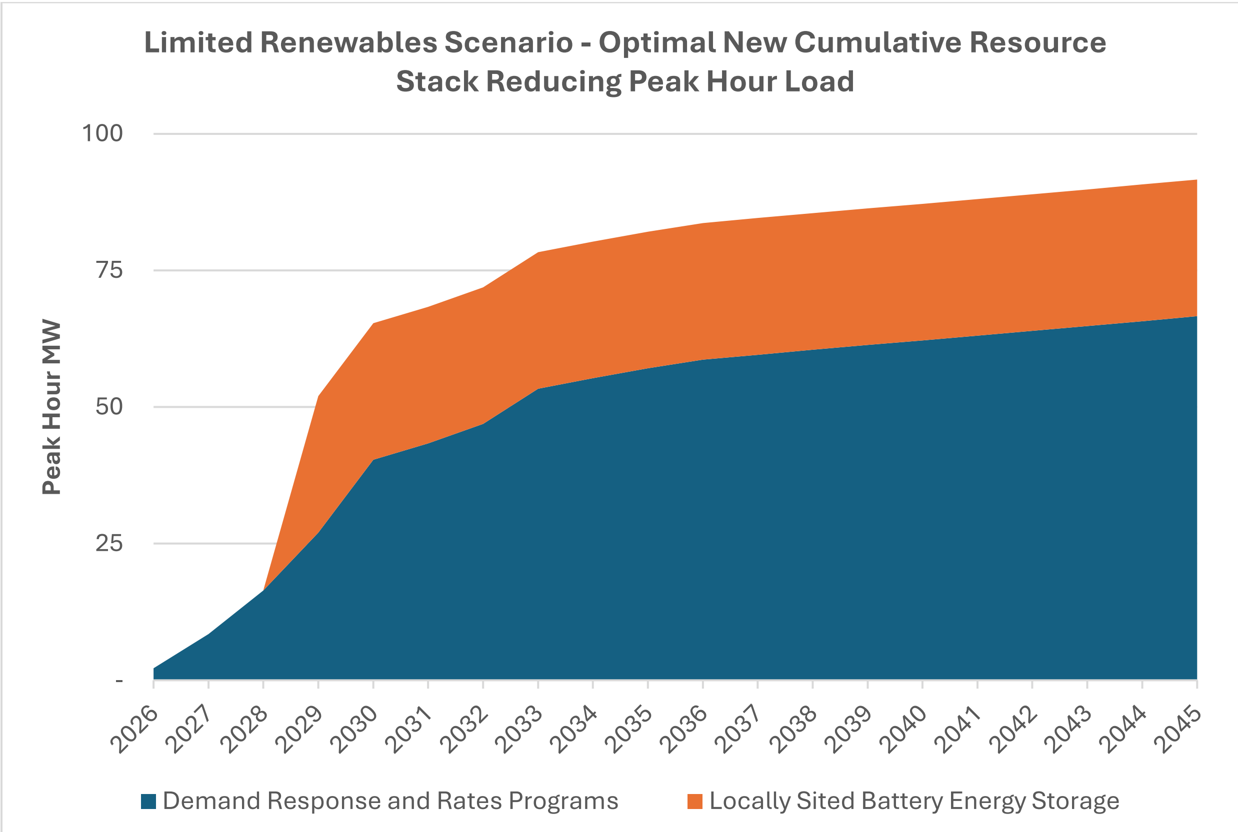


Figure 6-11 Limited Renewables Case Peak Demand Resource Additions



High BPA Costs Case

Figure 6-12 and Figure 6-13 show the resource additions for the High BPA Costs sensitivity. In this sensitivity, reliance on BPA for peak load service and Tier 2 service is dramatically displaced by other resources due to the increased BPA cost escalation assumptions built into this sensitivity. Local battery energy storage and utility-scale clean energy resources are acquired in larger relative quantities due to their lower costs to serve load growth and peak load.

Figure 6-12 High BPA Cost Case Energy Resource Additions

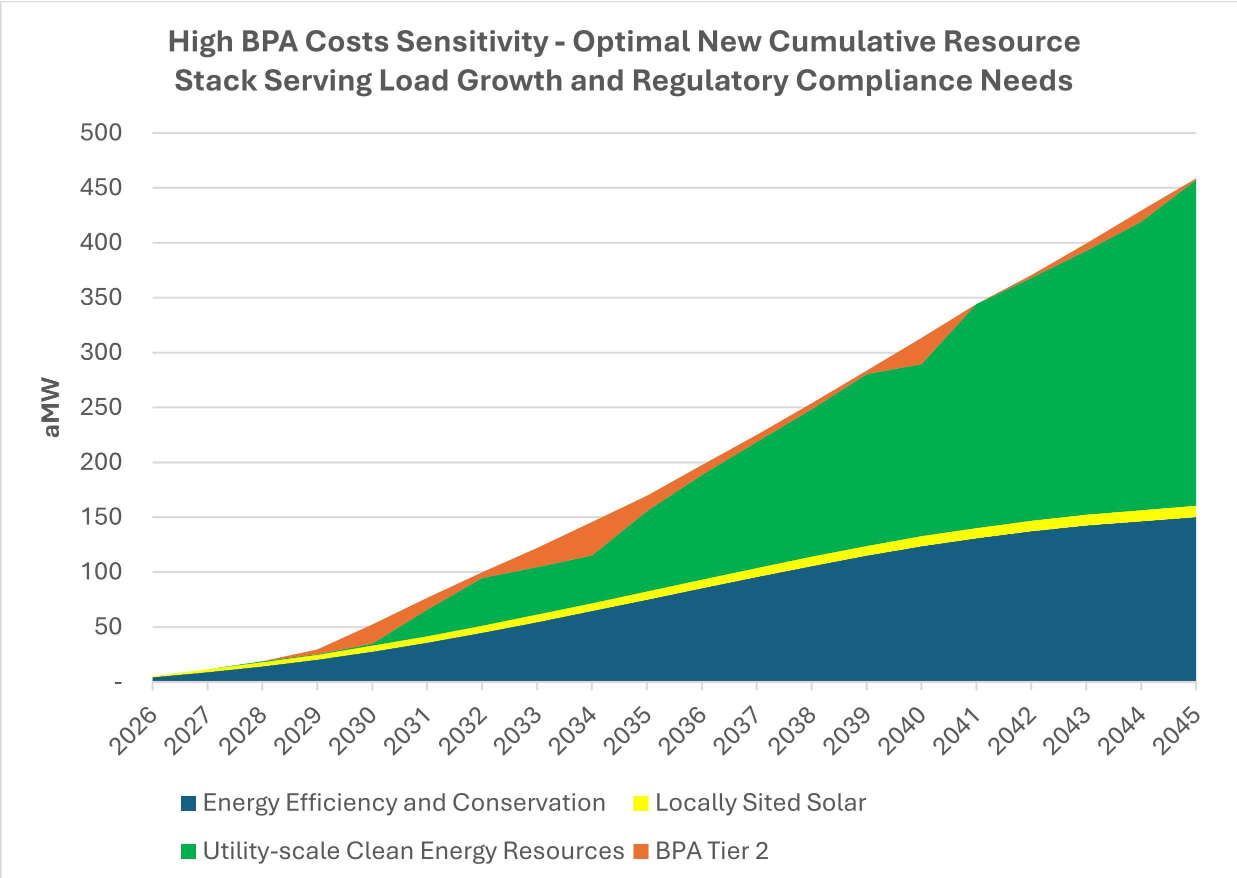
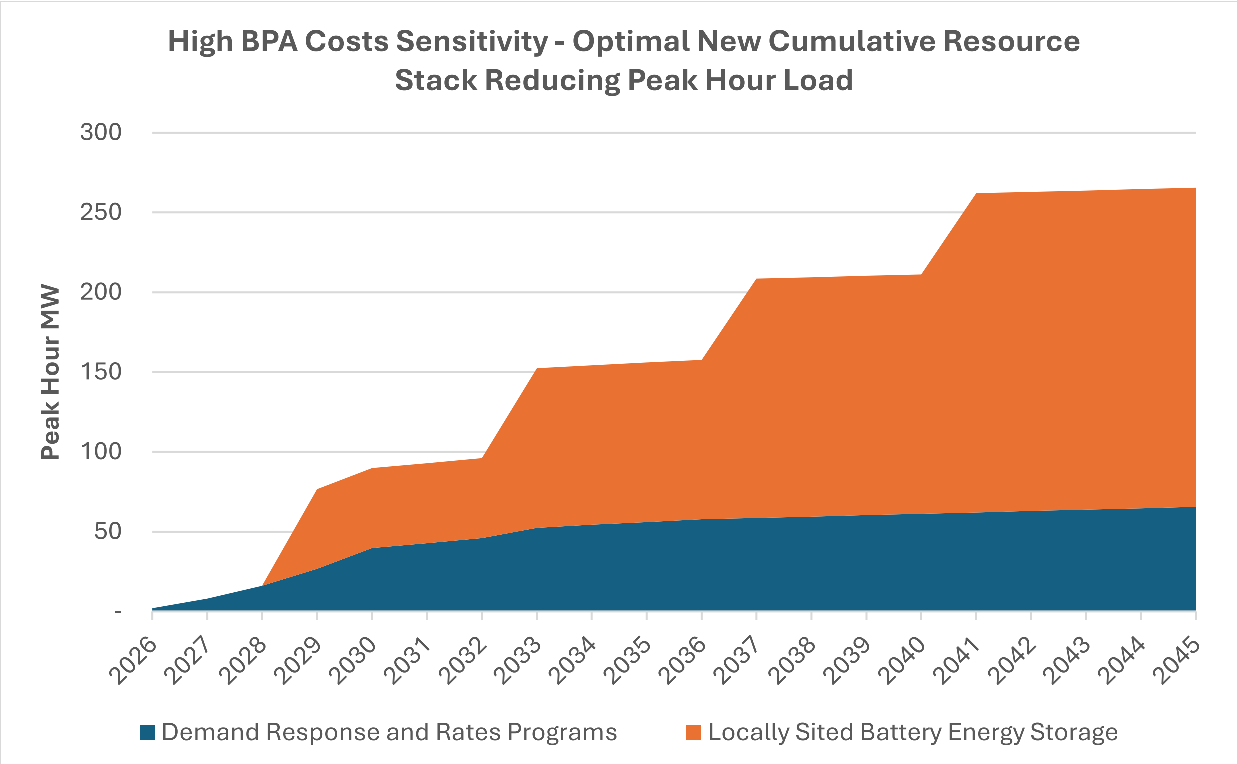


Figure 6-13 High BPA Cost Case Peak Demand Resource Additions



Low BPA Costs Case

Figure 6-14 and Figure 6-15 show the new resource additions for the Low BPA Costs sensitivity. Conversely to the High BPA Costs sensitivity, reliance on BPA for load growth and peak load service is relatively increased. Utility-scale clean energy resources are added only to meet regulatory obligations. Locally sited battery energy storage is not present in the resource plan because the BPA demand charge is a lower relative cost to serve peak load.

Figure 6-14 Low BPA Cost Case Energy Resource Additions

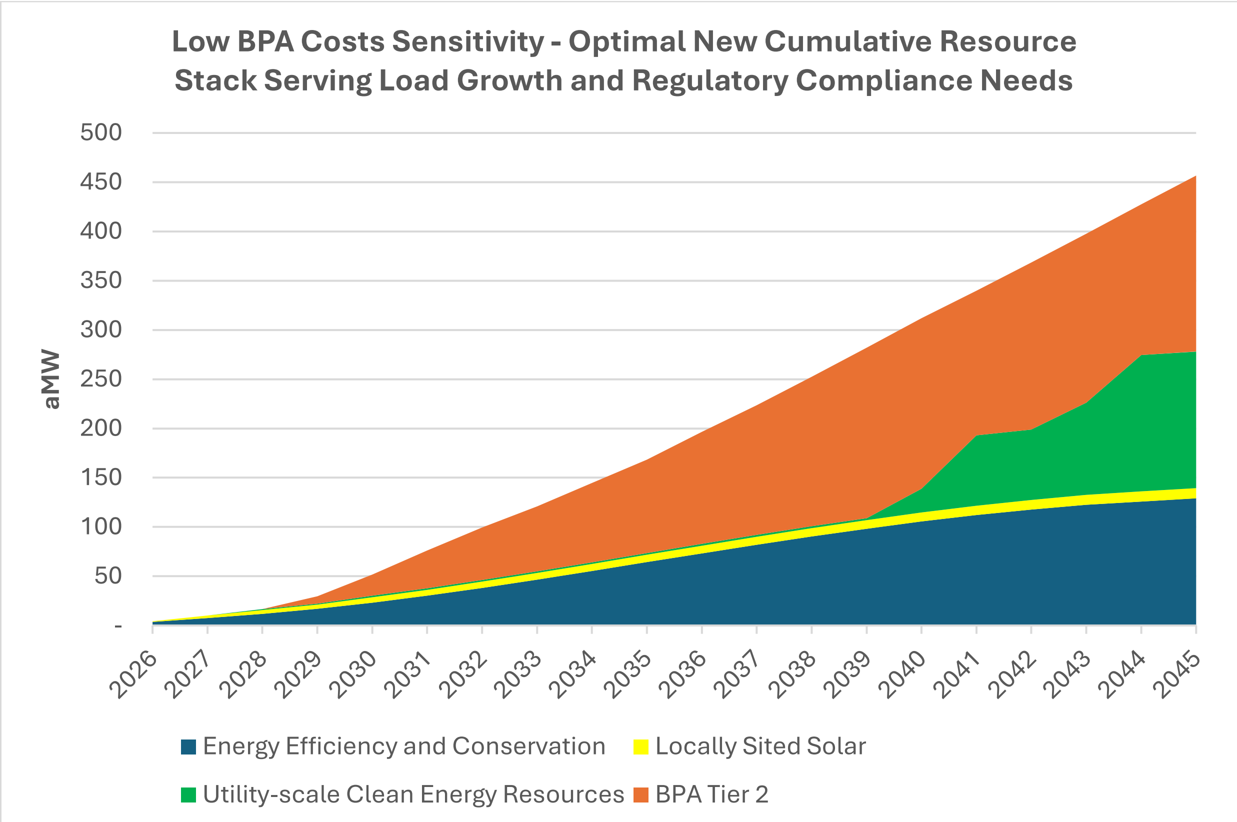
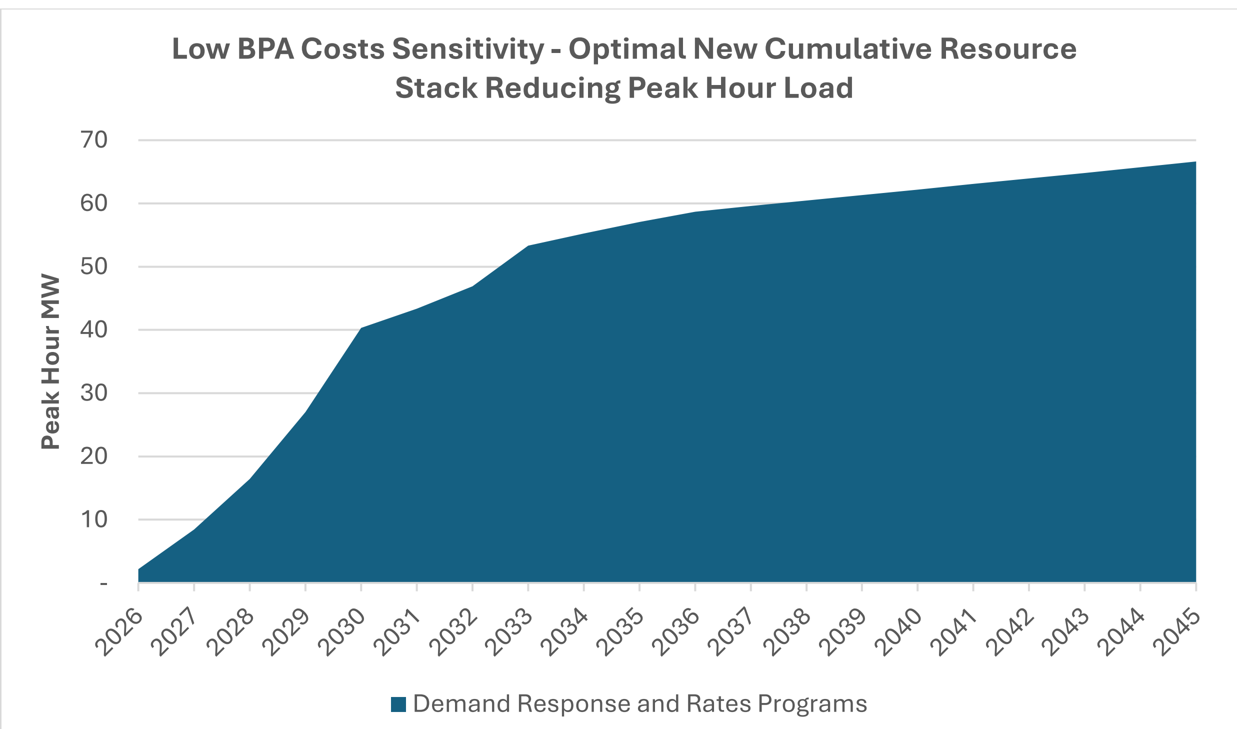


Figure 6-15 Low BPA Cost Case Peak Demand Resource Additions



Shallow Renewable Energy Credit Market Case

Figure 6-16 and Figure 6-17 below show the new resource additions for the Shallow REC Market sensitivity. New utility-scale clean energy and locally sited battery energy storage resources are added in this scenario to meet more relatively constraining compliance obligation targets.

Figure 6-16 Shallow REC Market Case Energy Resource Additions

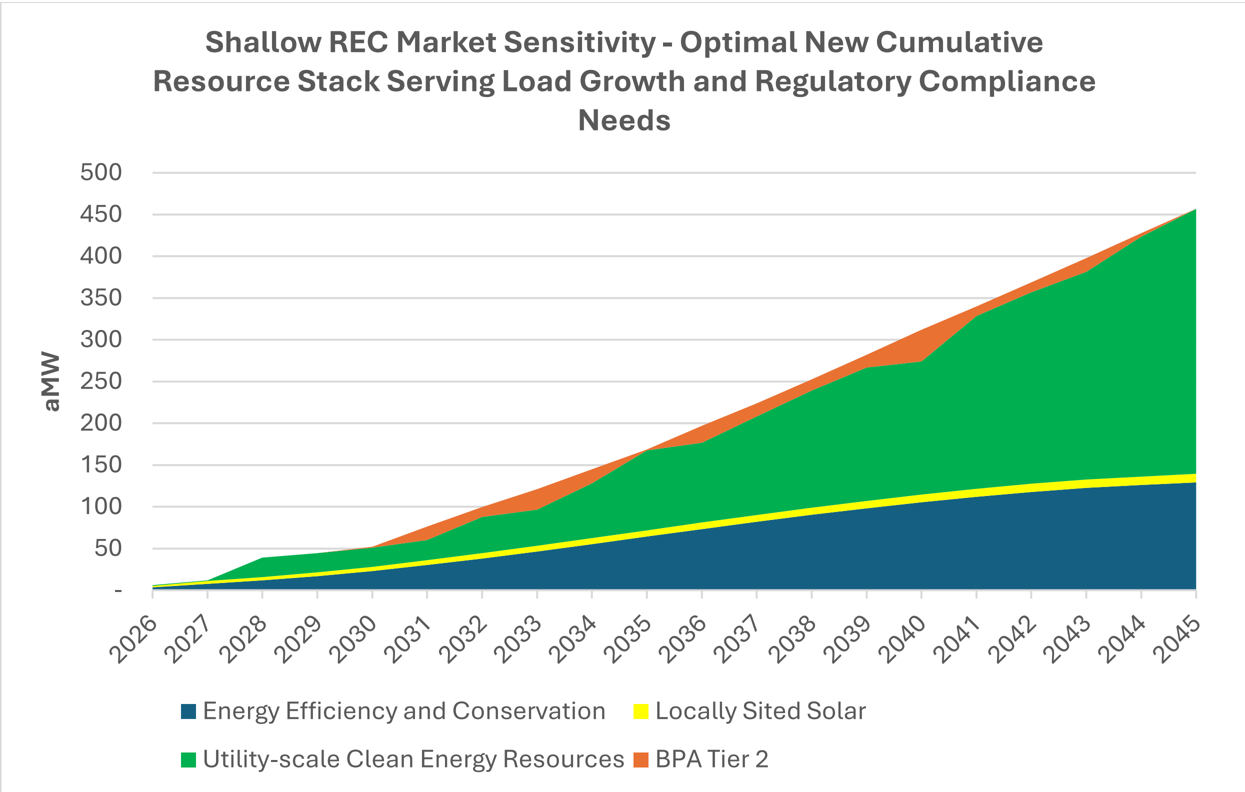
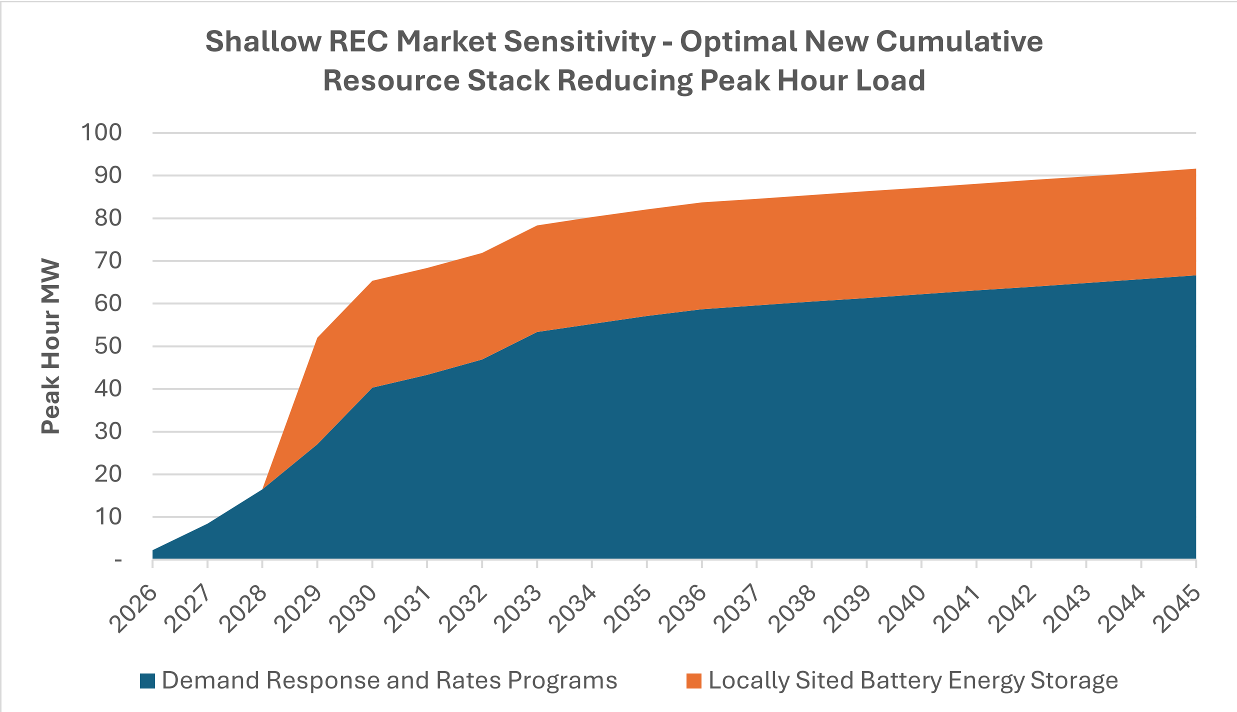


Figure 6-17 Shallow REC Market Case Peak Demand Resource Additions



CETA Only Policy Environment

Figure 6-18 and Figure 6-19 show the new resource additions to the CETA Only Policy Environment sensitivity. For this sensitivity, utility-scale clean energy resources are added to serve load alongside BPA Tier 2, and to meet regulatory requirement targets set forth by the CETA requirements. Locally sited battery energy storage is not added, and demand response and rates are added in less amounts, due to the lack of Energy Independence Act regulatory obligations as well as inability to compete against the relative costs of BPA's demand charge.

Figure 6-18 CETA Only Case Energy Resource Additions

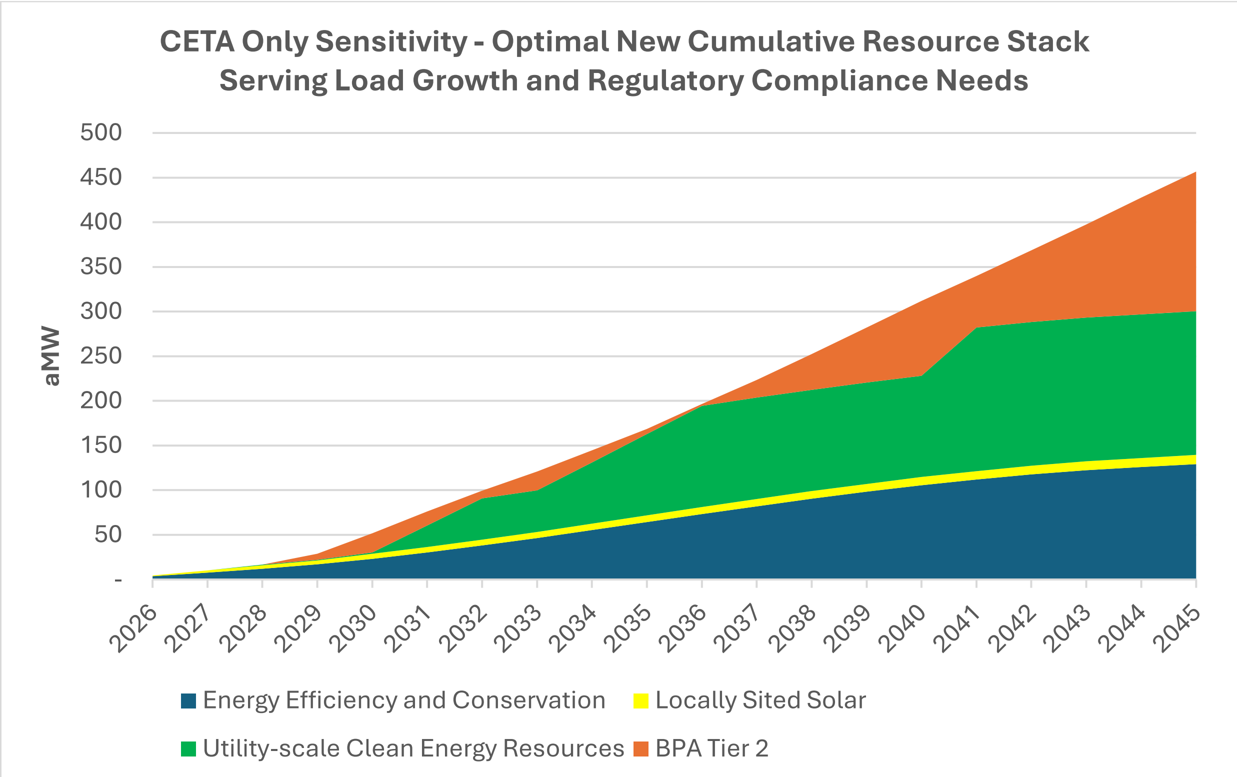
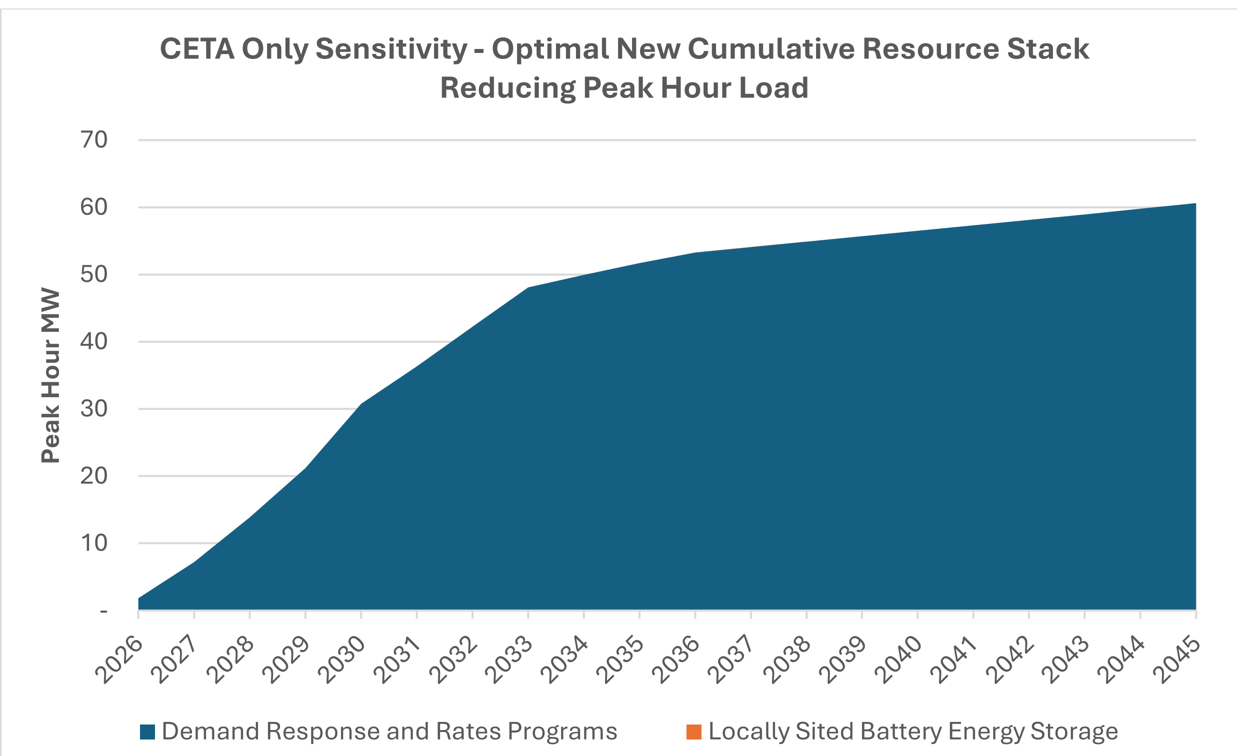


Figure 6-19 CETA Only Case Peak Demand Resource Additions



7 Key Insights and Action Plan

The 2025 Integrated Resource Plan takes place in a new planning environment with different constraints than past IRPs, however the plan remains like past resource plans. The central finding of the 2025 IRP is that conservation, demand response and renewable energy are core resource additions over the study period. Historically, short-term market contracts provided a bridge resource, but these are no longer required, and BPA Tier 2 becomes the bridge resource of choice, necessitating additional study of the attributes of long-term Tier 2. Clean energy policy compliance is a key consideration in the near and long-term study period leading to resource additions for environmental attributes as well as for load service. The preferred base case portfolio does not include energy storage, however several scenarios and sensitivities did, therefore additional due diligence is warranted.

While this is the central insight from the 2025 IRP, the totality of the analysis also provides insights into new opportunities, how the PUD can meet future challenges, and how risks presented themselves across scenarios. Conducting an integrated resource planning process every two years yields insights for our existing portfolio, planning assumptions used, and the alternate portfolios evaluated, regardless of which future unfolds. This is an added benefit of the IRP process. The following represents some of the key insights from the 2025 IRP analysis.

Key Insights

While a Long-Term Resource Strategy is identified quantitatively through economic analysis, it can also be evaluated qualitatively in terms of the key risks, opportunities, and organizational goals of the PUD. The following key considerations represent additional lenses for viewing a long-term resource strategy and can provide insights into factors outside the purely quantitative results.

Load-Following and the Post 2028 Contract

The PUD's long-term power contract with BPA expires in 2028 and the Long-Term Resource Strategy must be flexible enough to meet customer needs through the post 2028 product transition. Resource additions beyond the Tier 1 BPA service were evaluated for feasibility for least risk load service and regulatory compliance. Tier 2 service offers opportunities to mitigate resource delivery and transmission risks while acting as a buffer for additional renewable projects to be procured.

Electrification Needs

The PUD is forecasting growing loads under all scenarios in the 2025 IRP due to electrification of transportation and building heating and cooling. The long-term resource strategy needs to be flexible and capable of serving increased load as customers move to higher electric energy needs and is potentially sensitive to the policy environment.

Regulatory compliance drives acquisition

Clean energy regulatory compliance throughout the study period drive resource decisions and ultimately resource acquisitions. Complying with EIA and CETA requirements under the Load-Following BPA product requires a new strategy for the PUD compared to the Block/Slice Product. Tier 2 power was displaced throughout the study period for renewable energy resources for regulatory compliance credits.

Cost effective conservation continues to provide the PUD with significant value.

Conservation has been a consistently sound investment for the PUD for several decades. The analysis from this IRP cycle confirms this value and plans for significant additional investment over the 20-year study period. Available low-cost conservation is lower than prior IRP's based on past accomplishments, however the value of conservation remains high. Cost effectiveness for conservation has increased to achieve similar levels as prior plans.

Development of demand response and smart rate programs will help the PUD keep customer costs low, manage demand charges and give regulatory compliance value.

The 2021 IRP was the first PUD IRP to find Demand Response programs cost-effective. This was made possible by planned AMI investments bringing down the costs of acquiring demand response and smart rate programs. The 2023 Update continued to show the value of Demand Response and Smart Rate programs. This resource type has value in all scenarios helping contribute to peak demand management and regulatory compliance with the Energy Independence Act Renewable Portfolio Standards at very low cost. As such, Demand Response programs provide one component of a multi-component strategy to help meet future needs.

Technology Innovation

The electric energy sector has seen rapid development and adoption of new technology on both demand and supply sides. The cost of energy storage has dramatically decreased while project longevity has increased. Renewable generation sources are widely deployed, more mature, and produce electricity with greater efficiency. New emerging technologies are under development across the industry. The PUD's Long-Term Resource Strategy must be flexible to access price and capability advantages of new and maturing technology. This flexibility would likely include diversification across planned resource investments and multiple time horizons.

Community Values, Company Values, and Public Feedback

The PUD has a long-standing commitment to conservation and clean energy sources, and its customers have voiced support for continuing this approach in public venues. A resource strategy that utilizes resource investments within Snohomish County may provide customers and the community more public benefit than a resource strategy where more investments are made outside Snohomish County and Camano Island. Energy efficiency, demand response, and locally sited energy storage resources all represent resource investments in PUD communities. PUD staff engaged with the public frequently during the scoping and development of the 2025 IRP, and that feedback was important in shaping this study.

Risks and Opportunities

As the PUD evaluates the current landscape and executes the long-term resource strategy, it is essential to assess both the potential risks and emerging opportunities that may impact customers, strategic goals, or regulatory compliance. The long-term resource strategy seeks to quantify risks that could pose challenges, as well as highlight opportunities for benefit, by proactively understanding risks and seeking opportunities, the PUD can make informed decisions that improve outcomes for customers.

Key Risks

1. **Load growth is lower than anticipated and renewable procurement leads to stranded assets.**
   The long-term resource strategy acquires significant renewable resources largely for regulatory compliance with state clean energy policy. If load growth is lower than expected regulatory compliance requirements are lower, the PUD has the opportunity to slow the pace of resource acquisition or utilize more service from the BPA Tier 2 product. PUD staff should remain diligent to load growth trends and local economic conditions to modify resource procurements as needed for future conditions. BPA resource remarketing services under the RSS suite and/or marketing unbundled energy while retaining the environmental attributes are additional mitigation strategies available to the PUD.

2. **REC acquisition for regulatory compliance is more challenging than expected**

   The PUD will be sourcing unbundled RECs from the wholesale market for both EIA and CETA compliance for the foreseeable future. The REC market itself is somewhat opaque, and the depth of available RECs is a risk to the PUD's compliance strategy. The IRP places limits on the number of unbundled RECs available for purchase how the number on the open market is a function of regional loads, renewable buildouts and compliance needs of other Washington State utilities. Proactive REC acquisition mitigates the risk the PUD faces non-compliance penalties from insufficient REC volumes, and the PUD has begun a program of proactive procurement.

3. **Regional renewable buildouts are insufficient for the PUD's needs**
   The PUD has growing needs for energy for both regulatory compliance and load service while resource developments have been slowed by interconnection delays, transmission constraints and permitting challenges. The PUD resource plan uses renewable resources for regulatory compliance and the PUD faces the risk of competing in a constricted development environment with other organizations facing similar regulatory hurdles for a limited number of projects. The PUD can utilize BPA Tier 2 service if the non-federal procurement pace becomes unaligned with load service needs.
4. **BPA cost assumptions are incorrect**
   A core part of the long-term resource plan is the use of short-term Tier 2 as a bridge between resource procurements. PUD staff will evaluate the two Tier 2 products prior to finalizing a Tier 2 strategy and election prior to the 2028 contract. Tier 2 pricing may be higher than assumed, and if the PUD chooses a strategy dependent on long-term Tier 2, displacement is not possible leading to increased customer costs. Short-term Tier 2 offers options to displace with non-federal resources or wholesale market contracts mitigating the risk of stranded costs and the election provisions include a one-time option to reduce the PUDs fixed long-term Tier 2 amount. For these reasons, staff propose additional analysis in 2026 on Tier 2 options as more information becomes available to ensure Tier 2 elections are based on the best available information, and the election is compatible with a comprehensive strategy.

Opportunities

1. **Short-term Tier 2 offers planned market exposure if buildouts drive market costs down**
   The long-term resource strategy uses short-term Tier 2 as a bridge mechanism between supply-side resource acquisitions, however it also offers a way to access

planned market exposure if the wholesale market prices go down with regional buildouts. Short-term Tier 2 is fundamentally a market-based product with prices changing on a rate period by rate period basis through BPA's ratemaking process. The BPA resource program also includes significant market exposure for its own needs and if market prices are depressed long-term Tier 2 is assumed to include a substantial portion of market purchases. Both Tier 2 options therefore allow the PUD to access the wholesale market through BPA while also mitigating the risk of market exposure.

2. **Portfolio flexibility allows the PUD to respond and adjust to changing conditions**
   A flexible long-term resource plan enables the PUD to adjust and adapt to changing conditions to keep costs low while maximizing the PUDs ability to procure resources that best fit future needs in the environment the PUD finds itself in while using the shared resources from several scenarios. In all scenarios conservation, demand response, renewable energy and local solar were cost effective meaning these have value in a variety of possible environments and should form the core of the long-term resource strategy.
3. **The long-term resource strategy can mitigate demand charges through energy storage if the costs are appropriate**
   The PUD has opportunities to mitigate peak demand charges by gaining a comprehensive understanding of energy storage costs. A flexible long-term resource strategy can evaluate the relative costs and benefits of energy storage compared to alternative options, helping to identify the most cost-effective capacity additions as battery economics evolve due to policy shifts or technological advancements. While batteries were not cost-effective in the base case scenario, their inclusion in other scenarios suggests they are near the margin of viability. This indicates that changes in the planning or policy environment could change the economics, warranting further investigation. If costs become favorable, batteries could help offset BPA demand cost inflation and enable the PUD to shape its own strategic direction.

Long-Term Resource Strategy

Determination of the Long-Term Resource Strategy

Across all scenarios and sensitivities, energy efficiency and conservation, demand response and rates, utility-scale clean energy resources, and locally sited community-scale solar are cost-effective new resource additions, albeit at varying volumetric increments and varying timings of the increments. Additionally, all optimal portfolios have a limited but consistent embedded reliance throughout all years of the study period on wholesale unbundled REC purchases to meet regulatory obligation targets for both the EIA and CETA requirements. Generally, BPA short-term Tier 2 energy is used as a load-serving bridge between other new supply-side resource additions and as a backstop for any remaining load after new resource additions are added and after regulatory requirements are met.

Locally sited battery energy storage is chosen in scenarios or sensitivities where EIA compliance targets are more difficult or otherwise more expensive to reach relative to the Base Case, or when the assumed effective cost of this resource is relatively lower than in the Base Case or when BPA costs are increased such as in the BPA Increased Cost sensitivity.

The Long-Term Resource Strategy reflects the quantitative results of the Base Case scenario's optimized portfolio. The Base Case represents a reasonable load trajectory and operating environment while remaining flexible enough to react to large changes to load, operating environment or resource costs. The Base Case balances risks and opportunities faced by the PUD with optionality and flexibility moving forward for customers.

Near Term Resource Strategy

Near-term actions are decisions taken by the PUD in the next 2-4 years to serve load-cost effectively and prepare for the new 2028 BPA contract

Table 7-1 Near Term Resource Strategy

Cost-Effective Conservation	Cost effective conservation remains a key component of the PUD's long term resource strategy and provides the PUD with significant value. Conservation has been a consistently sound investment for the PUD for several decades. The analysis from the 2025 IRP confirms this value and plans for significant additional investment over the study period. **The biennial conservation target for 2026 - 2027 is 7.5 aMW.**
Demand Response and Smart Rate Options	Demand Response programs and Smart Rate options provide participating customers more control over their energy usage and peak demand allowing the PUD to incentivize demand shifts from higher-cost periods to serve to lower-cost periods. The IRP has showed the value of demand response and smart rates for several cycles

	in parallel with the roll-out of advanced meters that will make these rate options possible. The 2025 IRP targets an aggressive 26.6 MW of peak reduction capability by 2030.
Local Solar Energy	Local solar energy projects offer unique regulatory value and contribute to a low-cost portfolio. These investments take the form of two programs, utility scale solar and large customer owned solar. The 2025 IRP targets 5 MW of local utility scale solar before 2030 to maximize the regulatory benefit of the project. Large (>50kw) customer owned solar incentives are cost-effective in the long-term resource strategy. The IRP values the regulatory value and economies of scale offered by larger customer owned solar projects. The 2025 IRP targets 17.5 MW of large-scale customer owned solar by 2030.
Renewables and Clean Energy	The PUD does not face above high water mark load until the start of the BPA POC Contract and expects renewable project development timelines to exceed the 4-year timeframe for the near-term actions. However, procurement activities will need to happen during this period to achieve longer term goals.
Unbundled RECs	To meet clean energy requirements the PUD will need to proactively procure renewable energy credits for EIA compliance in the near term. Until new renewable resources can be acquired, unbundled RECs act as a bridge to 2030 when additional compliance requirements begin. The PUD plans to procure unbundled RECs based on load conditions and resource output from existing resources.
Tier 2	The PUD will use Tier 2 as a bridge between renewable energy procurements or as a basis for load growth depending on the composition of the long-term Tier 2 products. The PUD expects to have 7MW of

	Tier 2 exposure by 2030 and will make an election in 2026.

Intermediate Term Resource Strategy

Intermediate term actions are decisions taken by the PUD in years 5-10 of the study period to serve growing load needs and begin resource procurement for CETA compliance

Table 7-2 Intermediate Term Resource Strategy

Conservation	The PUD will continue to invest in conservation programs to manage load growth, lessen demand costs and regulatory compliance needs. The 10-year conservation estimate is 64.2 aMW by 2035.
Demand Response and Smart Rate Options	The PUD anticipates growing participation in demand response and smart rate programs as AMI deployment completes and programs are developed for additional segments of the population. As the PUD develops programs and begins education efforts the number of customers familiar with demand response and smart rates will grow and they will find a best fit program for their needs. These programs provide customers more control over their usage and help the PUD avoid demand charges. By 2035 the anticipated peak reduction capability is 56.1 MW.
Local Solar Energy	Local solar energy projects provide regulatory value across all years of the study and especially before 2030. However, it could be challenging to develop two projects of significant size prior to 2030. A further 5 MW of utility size local solar beyond the initial near-term additions is cost effective. Continued growth in the large size customer owned solar will grow the anticipated total local solar to 10 MW of utility scale local solar and 21.1 MW of large size customer owned solar.

Renewables and Clean Energy	Load growth and regulatory needs accelerate in years 5 to 10 of the IRP study increasing the need for renewable energy resources and the PUD will have above high water mark load to serve. To meet growing energy and regulatory needs the PUD will need to invest in additional renewable and clean energy projects. The PUD should prioritize projects that generate the most environmental attributes however the best fit resources will need to be determined by the PUD as needs grow and resources are developed. The IRP expects to acquire 200 MW of renewable energy resources for regulatory compliance and energy needs.
Unbundled RECs	Clean energy regulatory needs change in 2030 when the CETA provisions become a constraint. The PUD anticipates it will use alternative compliance for the portion of BPA's fuel mix supplied to the PUD. The PUD will no longer have direct market exposure and does not expect to have its own unspecified energy purchases however BPA performs balancing operations for its own needs. These balancing purchases are passed onto public utilities who take BPA power.
Tier 2	The PUD will continue to use Tier 2 as a bridge between renewable energy procurements or as a basis for load growth depending on the composition of the long-term Tier 2 products. The PUD expects to have 90MW of Tier 2 exposure by 2035. The volume of Tier 2 used for load service will depend on the Tier 2 election in 2026.

Long Term Resource Strategy

Long term resource decisions are actions by the PUD in the mid 2030's to 2046 to serve accelerating load growth in Snohomish County and Camano Island. Because the PUD adopts a new IRP every two years the specific strategy should adapt and evolve in response to conditions in the future.

Table 7-3 Long Term Resource Strategy

Conservation	The PUD investments in conservation help offset load growth and regulatory compliance needs. An estimated 129.2 aMW of conservation achievement by the end of the study period is anticipated.
Demand Response and Smart Rate Options	The late study period is characterized by increasing load and even further increased peak needs. Demand response and smart rates are fully deployed, and customer participation is ordinary. In 2045 the anticipated peak reduction capability is 65.6 MW.
Non-emitting resources	Non emitting resources become available in the late study period and offer unique attributes relative to variable renewable resources. The PUD anticipates 50MW of non-emitting resources coming online and acquired by the end of the study period.
Renewables and Clean Energy	Clean energy resources continue to be a backbone resource addition for load growth and regulatory compliance. The PUD continues to acquire renewable resources through the end of the study period and procures 500MW of renewable energy resources by the end of the study.
Unbundled RECs	The PUDs regulatory needs change over time as clean energy resources contribute to load growth. EIA compliance becomes less constraining while CETA compliance turns into the constraint. The PUD will continue to use alternative compliance mechanisms for a portion of its BPA power portfolio through the study period.
Tier 2	Short-term Tier 2 acts as a bridge between renewable procurements peaking at 84MW in the late 2030s before being displaced and reaching 60MW at the end of the study. However, procurement decisions will drive Tier 2 exposure and will be evaluated as needs occur.

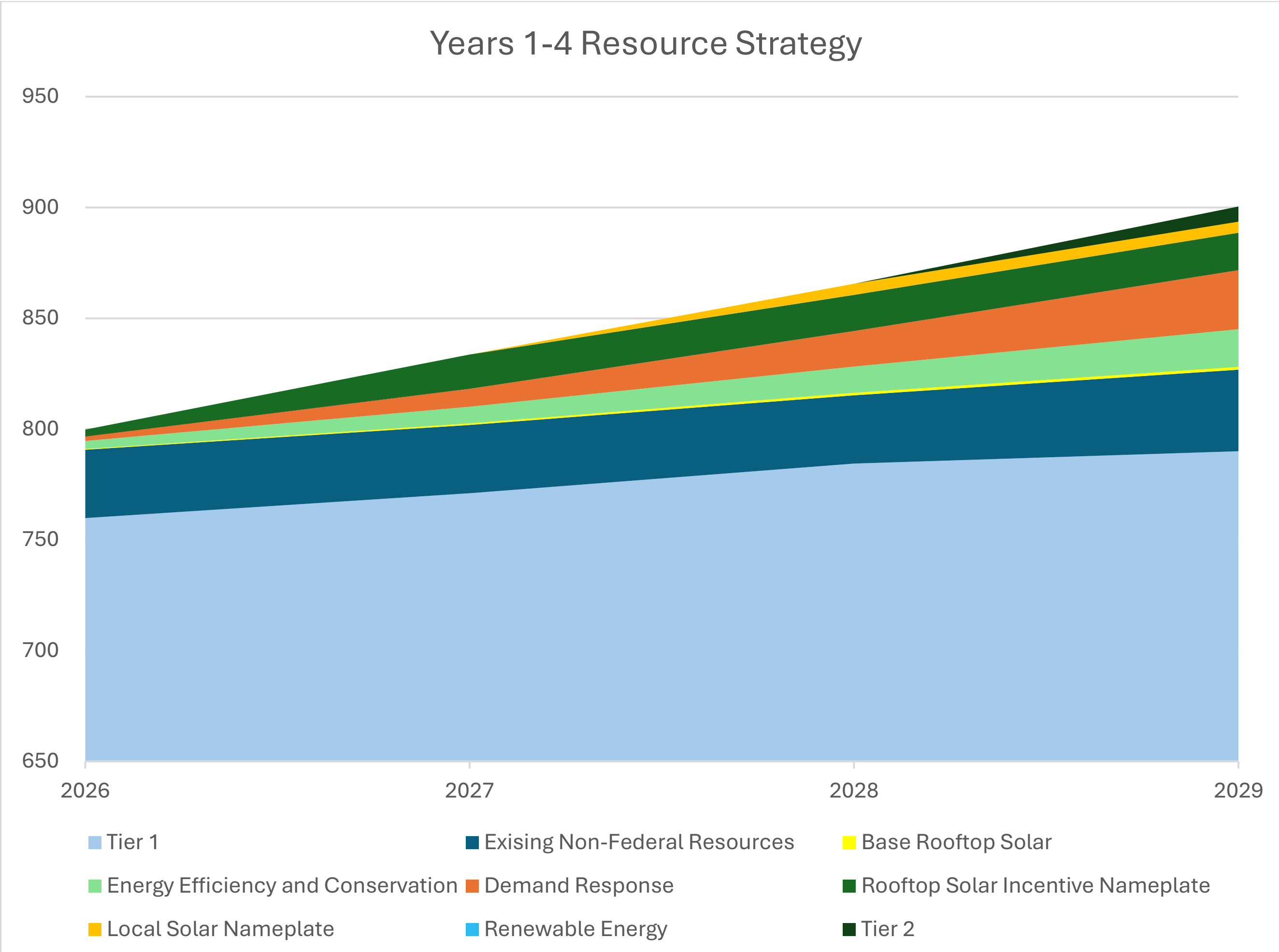
Resource Strategy Details

The foundation of the long-term resource strategy is described above and are shown below in graphical form. The resource strategy represents the lowest cost solution to the base case scenario as described in Sections 4 and 6.

Near Term Resource Strategy Details

The near-term resource strategy for years 1 to 4 representing calendar years 2025-2029. During these years the PUD transitions from the current BPA Regional Dialogue Contract to the new POC Contract and will have Tier 2 exposure, however the CETA requirements are not in effect. This period represents the next Clean Energy Implementation Plan reporting period and contains the EIA required biennial conservation targets. The resource strategy continues to use the Load-Following product into the POC Contract and a Tier 2 election will be made in 2026. Renewable energy resource development timelines exceed this study period and the PUD did not have enough above-high-water mark load to serve with a utility-scale renewable project, however due-diligence is needed during this period to enable acquisitions in the intermediate years. Tier 1 remains sufficient to meet the PUD's energy needs until the final year of the near-term period. Conservation, demand response and smart rates, and local solar investments provide a bridge to the intermediate term.

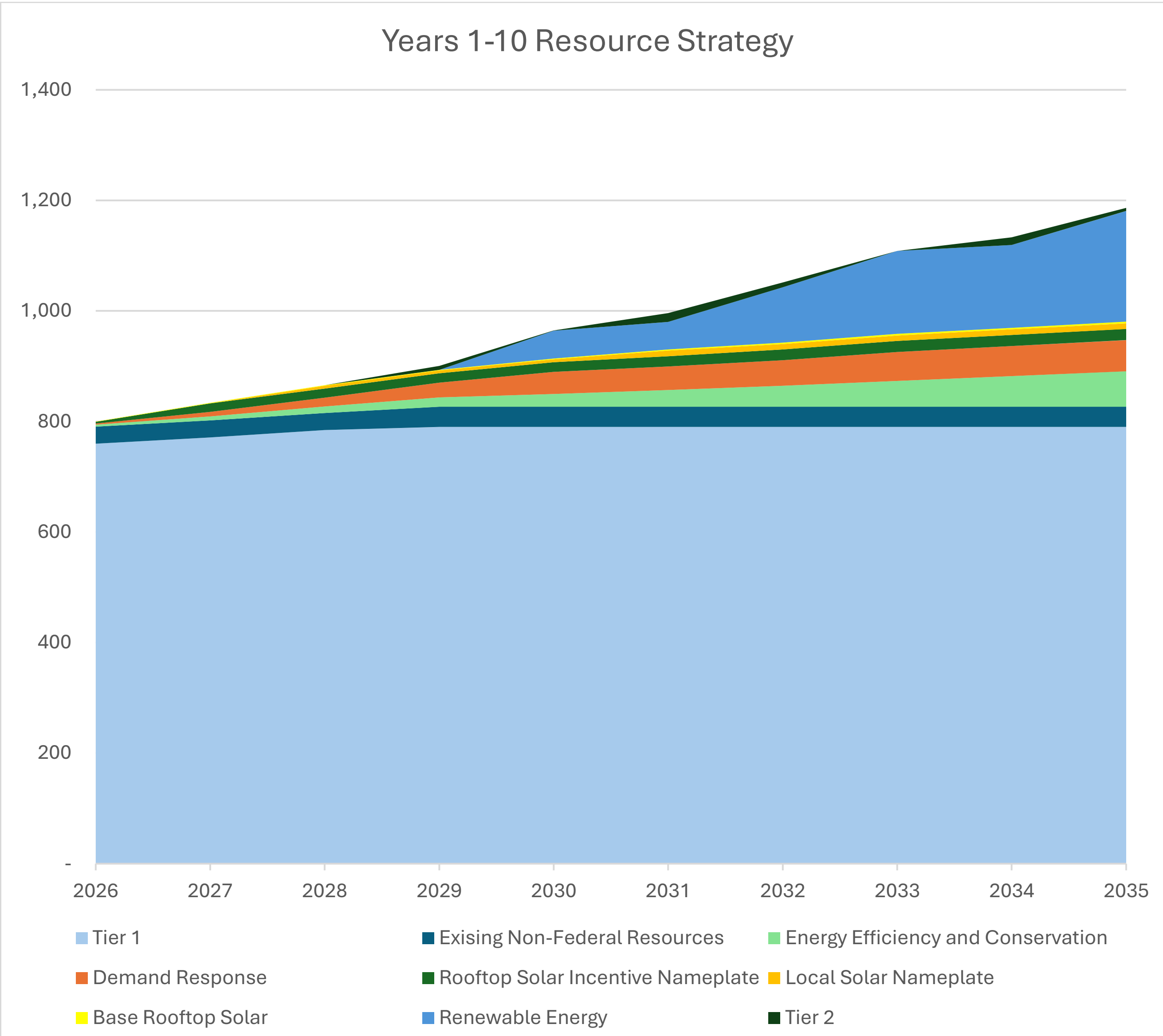
Figure 7-1 Near Term Total Resource Strategy



Intermediate Term Resource Strategy Details

The intermediate term of the resource strategy covers calendar years 2030 to 2035 and begins when CETA net-zero requirements take effect. Load forecasts increase in this period with Washington State electric vehicle mandates becoming binding, electrification increasing and inherent load growth growing, leading to above high-water-mark load. The PUD is expected to reach the contractual ceiling of its Tier 1 from 2030 until the end of the study period and resource additions are required to serve load growth. Supply side resource options are available in this period and technological advancements improve renewable energy efficiency while buildouts increase. Conservation remains a foundational resource for the PUD with demand response and smart rate capacities increasing to offset demand charges and providing regulatory compliance support. Renewable energy acquisitions increase for regulatory compliance needs and to serve load growth. During the intermediate term EIA compliance becomes less constraining as renewables are procured while CETA compliance becomes more challenging. The resource strategy shown below includes all years including both near and intermediate terms.

Figure 7-2 Intermediate Term Total Resource Strategy

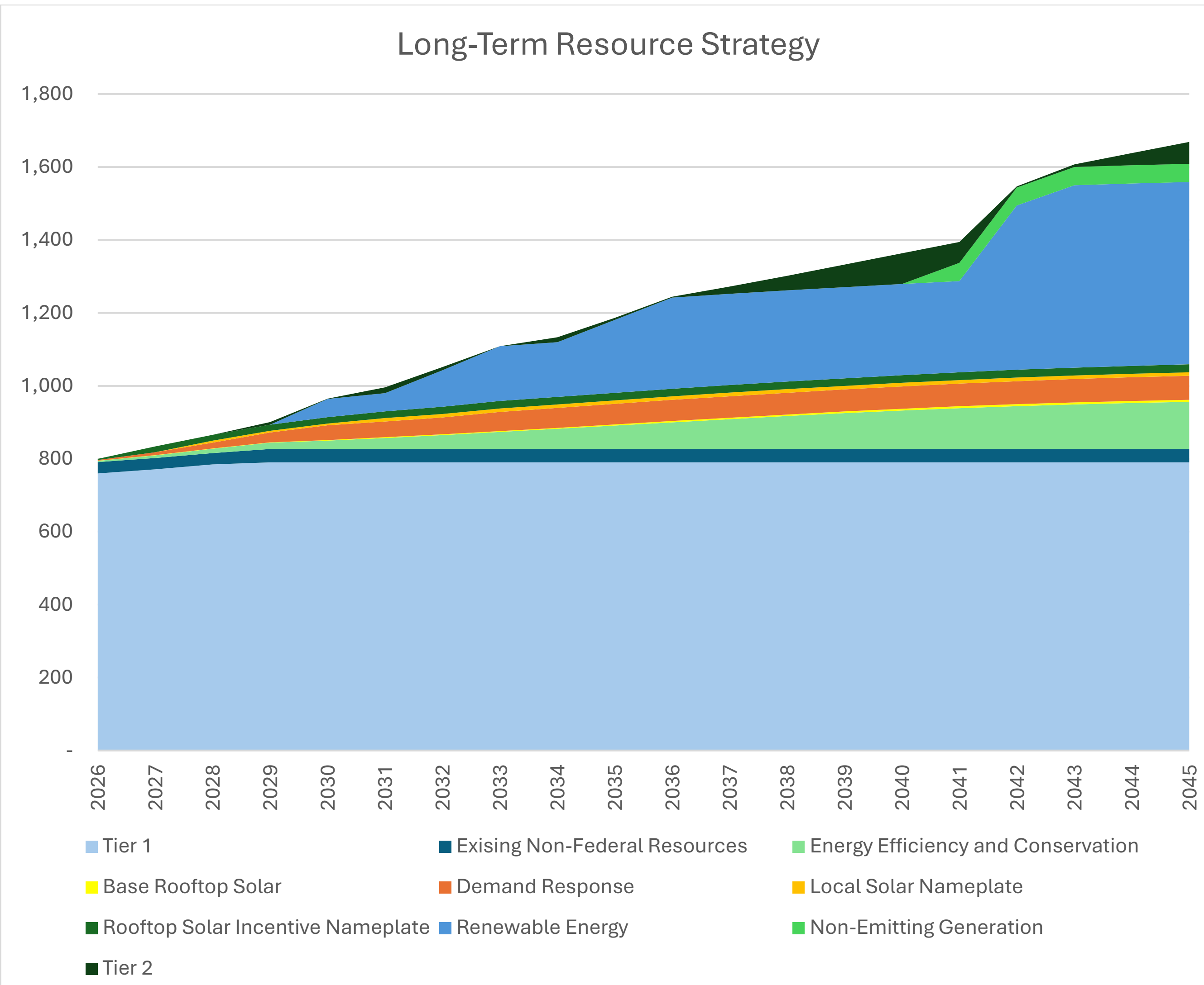


Total Resource Strategy

The resource strategy based on the Base Case covering all years is shown below and represents an economic optimization satisfying all clean energy regulatory requirements.

The IRP provides a flexible vision for the resources that will be added across the study period but will be updated in future IRPs as the later years get closer. Conservation remains a significant investment across the study period and combined with renewable resources provide much of the load growth service. Demand response and smart rate options grow throughout the study period to mitigate demand costs and provide regulatory value while EIA compliance is a constraint. The PUD will examine incentives for large customer-owned solar and this provides additional investments in customer resources. The strategy includes non-emitting resources in the final years of the study and developments in these sectors will be followed. Tier 2 acts as a buffer between resource additions and gets displaced with renewable resources when sufficient load growth occurs to need the resource output.

Figure 7-3 Long Term Resource Strategy



The resource strategy represents a flexible plan to meet future needs at the lowest reasonable costs while complying with all regulatory requirements and mitigating the risks the PUD could face over 20 years.

2025 Action Plan

The 2025 IRP has identified several near-term actions to ensure the PUD can meet the needs of its customers in a rapidly changing environment, well into the future:

1. **Acquire 7.5aMW of cost-effective conservation by 2027**
    - The 2025 IRP sets a biennial conservation target of 7.5 cumulative annual aMW for 2026-2027. Conservation remains a critical resource for meeting future load growth as it has in previous IRP cycles. The acquisition of conservation savings reduces the demand for electricity, delaying the need to acquire new resources and reducing the overall cost of energy and regulatory compliance for PUD customers.
2. **Develop cost-effective Demand Response & Smart Rates options, maximizing the regulatory and peak management value.**
    - The PUD AMI investment and the maturation of a variety of new customer-facing technologies allows for new options that could allow customers more control over their bills, and more tools for the PUD to work with customers to shape the PUD load profile into a more cost effective one. While the 2025 IRP identifies a variety of programs that would be financially cost-effective for the PUD, staff have identified that additional development work is needed to find the programs that provide the most value for customers and reduce PUD costs to the benefits of all customers. Development work should also consider staff resources required to launch and sustain programs. The IRP sets a 4-year target of 26.6 MW of peak reduction capability.
3. **Develop local PUD solar resources and explore programs for large (>50kW) customer-owned solar resources.**
    - The 2025 IRP finds that local solar could have increased value due to the BPA Power and Transmission product changes, recent state regulatory changes, and new features of the Post-2028 BPA Power contract. There are two local solar elements found cost-effective in the 2025 IRP: PUD-managed solar at larger (1-5MW) build sizes, and customer-owned solar at build sizes greater than 50kw. Accordingly, staff should:
        - Develop a plan to deliver up to 10MW of cost-effective locally sited, PUD-managed solar projects, in increments not to exceed 5MW, by 2035. This plan should prioritize the regulatory value of these projects granted by WA

State Bill 5445 and BPA's Post-2028 contract behind-the-meter resource incentives.

  - Assess the feasibility of developing and managing an incentive program for larger customer-owned solar projects (> 50kW) in partnership with local stakeholders. Large size customer owned solar projects are an underdeveloped market segment which offers unique benefits and economies of scale. Developing programs or incentives for large scale customer solar projects creates opportunities for the PUD to lower costs and acquire environmental attributes while being responsive to customer feedback on expanding customer solar options. Staff should develop a framework to effectively deliver cost-effective large-scale customer solar and ensure appropriate staff resources and organizational capabilities can support the framework.

4. **Perform due diligence on regional renewable energy projects, and prepare for potential procurement activity**
   - 200 MW of new renewables are identified in Years 3-10 of the Resource Strategy for clean energy regulation compliance and load growth. Renewable resources take time to develop and to prepare for potential renewable additions, staff will start due diligence activities now, making flexible procurement plans. Due diligence activities include but aren't limited to: evaluating the potential to access existing projects, monitoring regional RFPs and announced contracts for best practices and price points, evaluating transmission needs, talking with regional peers to identify partnership opportunities, and procurement activities like Requests for Information (RFI) and Requests for Proposals (RFP).
5. **Perform additional analysis on Above-High-Water-Mark load service options**
   - The PUD will choose a Tier 2 election strategy in 2026 for above-high-water-mark service. At the time of the 2025 IRP, BPA has provided limited information on the contents of the Long-Term Tier 2 product option, and the 2026 BPA Resource Program was not completed. PUD staff expect additional information before the Tier 2 election deadline and anticipate performing additional analysis to ensure that the PUD makes an appropriate election and makes any needed adjustments to resource planning in response to that election. PUD staff will provide the results of the analysis to the Commission with a recommendation to inform Commission decision-making.
6. **Ensure compliance with clean energy mandates**
   - The PUD is committed to meeting or exceeding clean energy and carbon regulatory requirements, and the PUD's portfolio is well-positioned to do so. The IRP forecasts a need to acquire Renewable Energy Credits (RECs) in the near-term

to augment portfolio resources and meet Renewable Portfolio Standards. PUD staff will:

  - Continue to develop its REC procurement framework to mitigate risks and employ lowest cost strategies.
  - Implement the Clean Energy Implementation Plan and Clean Energy Action Plan contained in the 2025 IRP per the Clean Energy Transformation Act statute.

7. **Perform due diligence on local battery energy storage**
    - Staff should continue to perform due diligence on utility-scale local battery projects including quantifying cost savings via in-house development, quantifying local transmission and distribution system value, and considering the strategic value of reducing regional transmission system risks while working with local stakeholders. The results of the due diligence process should inform a comprehensive strategy for local energy storage.
8. **Explore partnerships with local fusion energy companies**
    - Snohomish County is home to a developing fusion energy sector and the PUD is well positioned to further relationships with local fusion energy developers. The PUD will appropriately support local fusion companies and continue to follow advances in this sector.
9. **Continue to engage in regional transmission policy and planning efforts to ensure sufficient transmission capacity to serve load**
    - Regional transmission availability and reliability is a topic of sector-wide concern and PUD staff should continue to be at the table on behalf of PUD customers to advocate for projects and policy that reduce risks and follow sound business principles.
10. **Continue to engage in Organized Markets development.**
    - Various regional discussions on RTOs, Day Ahead Markets, and other market structures can present new risks and opportunities for the PUD. To adequately plan and influence market formation and design, PUD staff should continue to participate in relevant discussions, evaluations, and exploratory efforts to mitigate risks and develop new opportunities for the PUD on behalf of its customers. Specifically, staff should continue advocacy to ensure hydropower is appropriately valued, that the economic opportunities and risks of planned dispatchable resources are accounted for, and regulatory compliance is facilitated.
11. **Demonstrate regional leadership on power, transmission and policy issues.**

- Regional issues require the active engagement by subject matter experts to guide policymaking that could have significant implications for risks, costs, and opportunities for PUD ratepayers. Accordingly, staff should:
    - Continue to engage in local, state and federal policymaking for energy-related issues. Analysis in the 2025 IRP has found that state regulatory compliance obligations drive resource builds and that alternative regulatory compliance structures can produce cost savings for PUD customers. PUD staff should continue to be engaged with local, state and federal policymaking that can help meet clean energy and carbon goals at the lowest reasonable cost to ratepayers.
    - Continue to advocate for sound business principles and sound policy in BPA proceedings to achieve low and stable cost trajectories of BPA Power and Transmission products. BPA continues to be an integral part of the PUD's long-term power supply and keeping BPA's costs low and stable is a critical method of mitigating cost pressures on our customers. Collaborative efforts with BPA to ensure sound business practices and sensible policy objectives are followed and met will ensure BPA's long-term financial sustainability and stewardship of the regions unique resources.

12. **Continue to build and enhance community engagement on long-term planning**
    - PUD staff should continue to develop and enhance community engagement efforts in the development of long-term plans. This customer-centric approach will help ensure that planning efforts meet the needs of customers and incorporate the feedback from customers.
13. **Continue to advance the PUD's long-term planning tools to capture more risks, opportunities and scenario-planning tools with the goal of achieving lowest reasonable costs for customers.**
    - PUD staff should continue to work cross-functionally to capture the potential of local resources to defer infrastructure needs and costs on the T&D system. Systematically capturing such opportunities within Resource planning and T&D System planning efforts has the potential to identify cost-saving investments across PUD business lines. Specifically, staff should:
        - Develop and solicit an RFP for a new Demand Side Services support contract to deliver updated Conservation Potential Assessment, Demand Response Potential Assessment, and Solar Potential Assessment studies based on staff recommendations.

    - Continue to advance the Load-Following Optimization Model for the IRP, incorporating more tools to capture risks, opportunities, and deeper scenario analysis.

14. Develop a strategy and framework to manage new large load requests

- PUD staff should work collaboratively across departments to develop a strategic framework for managing new large load requests. The increasing volume of these requests presents significant implications for the PUD and warrants further analysis before service commitments are made. A comprehensive framework is needed to guide the evaluation and processing of future large load requests.

Appendix A. Clean Energy Action Plan

Clean Energy Action Plans (CEAPs) are a component of utility resource planning introduced by CETA. The purpose of the CEAP is to identify the planned actions over the next 10 years to meet specific goals of CETA. The 2025 IRP contains the CEAP in its 10-year vision of the Long-Term Resource Plan, and it presents the Long-Term Resource Action Plan's contributions to long-term clean energy goals. The PUD does not plan to add emitting resources to the portfolio; only renewable and non-emitting resources will be considered for meeting future load growth. However, because BPA's portfolio passes on a portion of its unspecified market purchases, the PUD expects to achieve 2030-2044 compliance through REC purchases.

Clean Energy Action Plan Summary

The 10-year CEAP has identified the following resources to be added by 2035 as shown in Figure 7-2 Intermediate Term Total Resource Strategy.

Table A - 1 Clean Energy Action Plan Targets

	2035 (10-Year)
Conservation (Cumulative annual aMW)	**64.2**
Demand Response (Cumulative MW Peak Reduction)	**56.1**
Distributed Energy Resources (Nameplate MW)	**34.0**
Renewable Resources (Nameplate MW)	**200**
Non-Emitting Resources (Nameplate MW)	**0**

The PUD uses the WRAP resource adequacy standards as defined by the WRAP program as its resource adequacy standard. The PUD will comply with the WRAP by purchasing the WRAP-compliant Load-Following Product from BPA.

To help plan for and meet the PUD's transmission needs, the PUD will utilize BPA's NT product for load service. This product allows the PUD to identify network loads and resources used to serve its needs, which BPA then manages. As an NT customer, BPA is responsible for planning and providing load service for any and all identified customer loads.

Snohomish will engage with BPA's planning processes to ensure that firm transmission continues to be available for serving its customers.

Appendix B. Clean Energy Implementation Plan Snapshot

The Clean Energy Implementation Plan (CEIP) is to be informed by the IRP but include separate public process results and assess specific questions contained in the law not included in the IRP. The 2025 CEIP is a separately published document, however, this appendix provides a resource-related snapshot as a companion to the 2025 CEIP.

Clean Energy Implementation Plan Summary

For the 4-year CEIP horizon the IRP has identified these resources as additions by the end of 2029.

Table B - 1 Clean Energy Implementation Plan Targets

	2029 (4-Year)
Conservation (Cumulative annual aMW)	**17.0**
Demand Response (Cumulative MW Peak Reduction)	**26.6**
Local Solar (Nameplate MW)	**23.7**
New Utility-Scale Renewables (Nameplate MW)	**0**

Appendix C. Public Process

The PUD utilizes an extensive public process to inform the development of long-term plans and has a customer-centric approach to planning. The public processes are intended to understand the perspectives of customers, incorporate analysis of interest to customers, and provide transparency for customers throughout the planning process.

The public engagement process has been expanded and developed from the 2021 IRP and 2023 IRP public processes incorporating feedback from attendees. The 2025 IRP public process integrated both IRP and clean energy implementation plan questions to gather feedback from our customers regarding their thoughts on the utility planning scope and clean energy actions and associated impacts. The PUD hosted one community leaders listening session, two traditional open houses, two community open houses, one virtual PowerTalks open house and a table at the energy block party for customers to engage with the PUD to give feedback.

IRP Listening Session

On May 23, 2024, the PUD hosted a listening session with 18 members of large businesses, non-governmental service organizations and governmental planning teams from Snohomish County and Camano Island. These organizations represent a wide cross section of insight into energy opportunities the community has, and potential challenges businesses and individuals could face in the IRP study timeframe.

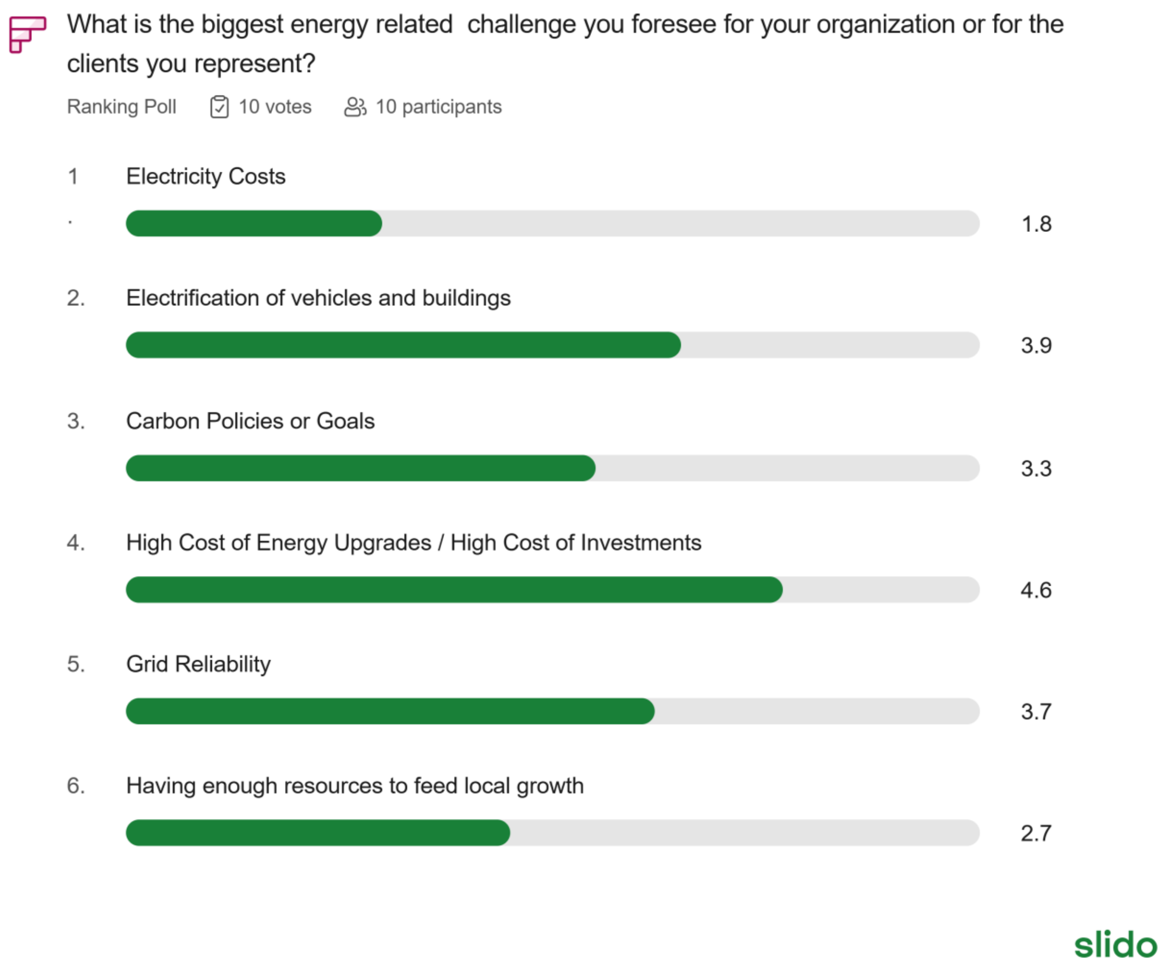
Customer feedback included the following (paraphrasing used here for clarity and brevity):

- Fleet electrification is probable in the PUD’s service territory. Several individuals mentioned their organizations were exploring potential to change their fleets to electric vehicles outside of the traditional goods transportation sectors.
- Residential adoption of electric vehicles for energy burdened or low-income customers is challenging. The cost of electric vehicles are a high barrier to adoption.
- Electrification of processes is an opportunity for customers with fossil fueled systems however upgrades are complex and represent a large investment.
- Reliable power supply and developing new technology and programs were the highest priorities for attendees. Several organizations indicated reliability and resiliency were related but offered different value to the organization. Both were high priorities for customers.

- Cost of energy upgrades and investments were the biggest challenges across sectors. Supply chain challenges represented additional challenges to upgrades depending on the type of upgrade.
- Clean energy and sustainability developments were most exciting with several mentions of news stories on new generation technology breakthroughs.

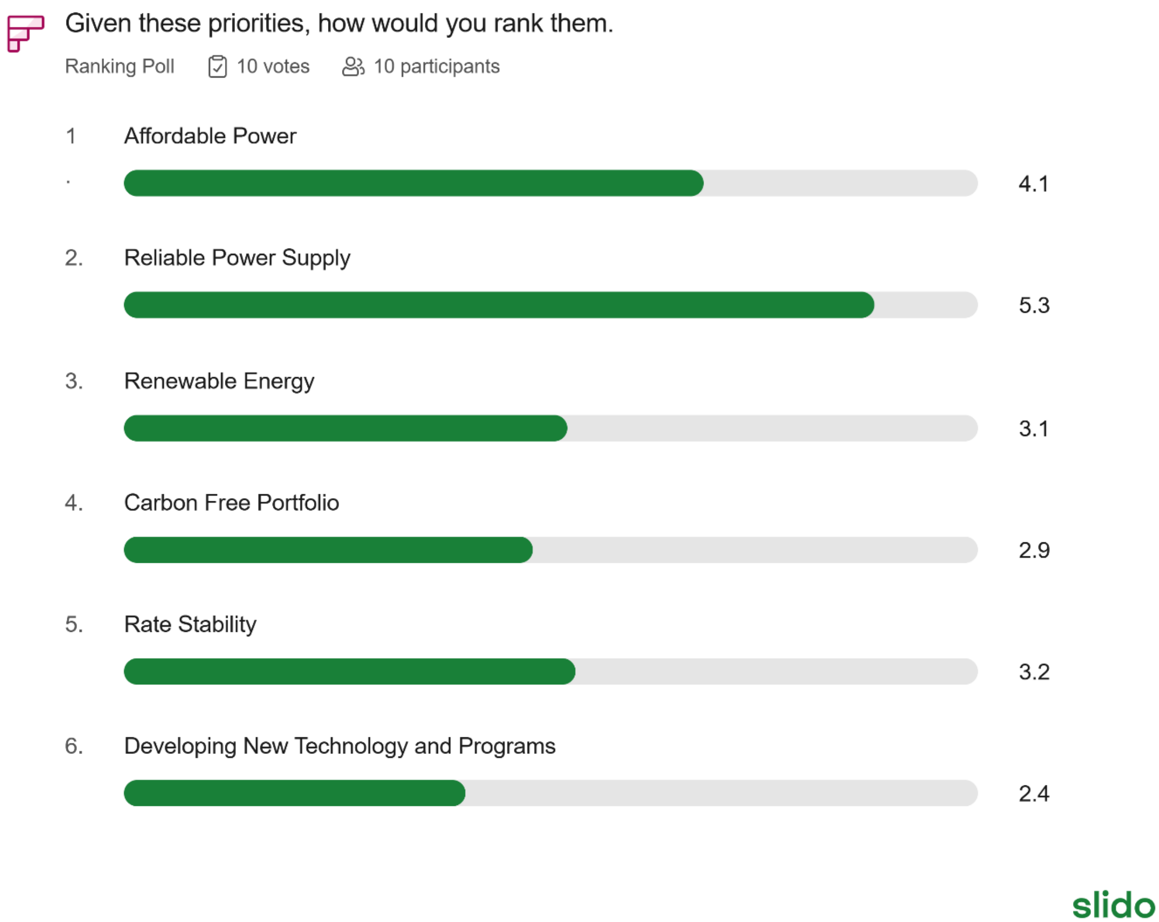
Figure C - 1 Most Exciting Aspect of the Energy Future

Figure C - 2 Largest Challenge for the Energy Future



Amongst the community leaders across the business, public service and government sectors sustainability was an opportunity for the future rather than a hinderance. A common thread among responses was the clean energy future was a high priority for all these community leaders and several mentioned environmental efforts or corporate sustainability initiatives. The biggest challenge the leaders responded with was the costs of upgrades for electrification or conservation, electrification of buildings and facilities and grid reliability. Across sectors responses were aligned with opportunities and challenges implying the PUD can impact our community in positive ways that benefit all segments of our customer base with thoughtful resource planning.

Figure C - 3 Ranked Priorities



Community leaders indicated reliable power supply was the highest priority meaning both resource sufficiency for future needs and enough grid support to deliver power. Affordability and keeping rates low was a high priority for industrial customers and organizations serving low-income customers as these customers are disproportionately impacted by rate increases meaning sound fiscal planning is paramount through the IRP process. Customers did not indicate new programs, or technology was a high priority relative to other priorities they did mention that new program and technology were an opportunity to impact other priorities such as costs and reliability.

IRP Open Houses

The PUD hosted four public engagement events: two traditional-format open houses and two gamified community events. The traditional open houses took place at the Everett headquarters and at the Arlington Clean Energy Center. The community events took place at Cedar Valley Community School and a senior center in Snohomish County. Across all events, nearly 100 community members engaged with the IRP team to share their perspectives on the IRP study.

To gather feedback, PUD staff used Slido, an interactive tool, during the traditional open houses. For the community events, similar questions were presented in a gamified format, encouraging more dynamic and conversational interactions. All events featured consistent content and questions to ensure feedback could be compared evenly.

Participants received a high-level overview of the IRP process and how their input would influence future planning. Feedback questions focused on electric vehicles, home electrification and heating systems, customer priorities, and perceived challenges.

Key insights included:

- Most participants did not currently own electric vehicles, though about half were considering purchasing one.
- The majority had not installed new heating or cooling systems or switched fuel sources for cooking or heating.
- Heat pumps and heat pump water heaters were the most commonly supported energy-efficient upgrades.
- Customers ranked **renewable energy** and **affordable electricity** as their top priorities, followed by **reliability**. While **stable rates** were seen as beneficial, they were ranked lower in priority.

Perceived challenges varied by event type. Attendees at traditional open houses identified **resource adequacy** as the biggest concern, while those at community events highlighted **building and vehicle electrification** and **carbon policy** as key challenges.

Power Talks

The PUD hosts virtual meetings open to customers on specific topics called PowerTalks. These PowerTalks offer an online format to engage with customers that may prefer a virtual option to join. In September the topic of PowerTalks was *“The Clean Energy Future and How the PUD Plans for It”*. Garrison Marr, Kris Scudder and Landon Snyder joined to give an overview of the IRP process, the core questions of this IRP and the timeline of the 2025 IRP. PUD customers and staff were attending the webinar and had time at the end of the presentation for questions. Customer questions germane to resource planning were on the plans for time of use rates and fusion energy in the IRP.

As a result of customer feedback, the 2025 IRP included a solar potential study as described in Solar Potential Assessment. No additional technologies were considered based on public feedback, however based on subject matter expert opinion geothermal energy was considered.

Energy Block Party

In both 2024 and 2025, the PUD hosted its annual Energy Block Party, featuring numerous booths where staff engaged directly with customers. The IRP team participated by hosting a booth focused on the future of the PUD's power supply and planning process. Customers were invited to ask questions and share feedback, including which energy-efficient technologies they were most likely to adopt—such as electric vehicles, heat pumps, air conditioning units, or heat pump water heaters. Electric vehicles emerged as the most popular choice, though many attendees expressed interest in learning more about all available energy-saving options. Additionally, customers voiced strong support for rooftop solar programs, the exploration of emerging technologies, and the pursuit of carbon-free energy solutions.

Commission Briefings

PUD staff provide briefings during the development of the IRP to provide Commissioners an opportunity to provide feedback, and for additional public transparency of the process. PUD staff break the IRP process into 5 phases, and these phases are shared sequentially (sometimes in groups). These Phases are as follows:

- Phase 1: Definition of study scope
- Phase 2: Calculation of resource need given load and resource forecasts
- Phase 3: Evaluation of Resource Options, including cost and capability
- Phase 4: Portfolio Optimization
- Phase 5: Resource Strategy and Action Plan

Briefing 1: March 19, 2024

This briefing kicked off the 2025 IRP process, with staff presenting a refresher on what an IRP is, some anticipated areas of study, the overall timeline, and proposed public process. Secondly the Commission was briefed on the CEIP requirements and how the CEIP aligns with the IRP public process.

Briefing 2: January 21, 2025

Following an extensive public engagement process and input from a technical team of subject matter experts, staff presented the proposed IRP study scope to the Commission. The presentation included a summary of public feedback and an analysis of study factors identified by the technical team, evaluated based on their potential impact and likelihood.

Briefing 3: April 8, 2025

The third briefing discussed the Phase 2 results and presented the load growth projections and projected resource needs. Staff explained the Load-Following products interaction with resources, and a brief introduction to Tier 2.

Briefing 4: June 17, 2025

The fourth briefing presented the resource menu for the Commissioners feedback. Commissioners were briefed on the results of the CPA, DRPA and SPA studies, the supply side resource menu and BPA Tier 2 service.

Briefing 5: August 19, 2025

The fifth briefing summarized the outcomes of Phase 4 of the Integrated Resource Plan (IRP), focusing on the results of the optimization process. It presented the base case scenario along with the 4- and 10-year portfolio additions, highlighting key strategic insights. Core resource additions were evaluated across the IRP scenarios, providing a comparative view that informed the foundation of the long-term resource strategy.

At the time of writing the phase 5 and final briefing are upcoming with the Commission. The planned public hearing will follow the final briefing, and adoption will occur by the end of 2025.

CEIP Incorporation

The PUD employed an integrated public engagement process to support the CEIP and ensure alignment between resource planning and CEIP outcomes. A key objective of this process was to gather public input on the definitions of vulnerable populations, as outlined in the CETA.

To maintain consistency in evaluating metrics and tracking the impacts of specified actions over time, the PUD recommended continuing with the definitions of vulnerable populations established in the 2021 CEIP. Feedback collected during the open house sessions helped identify the most impactful metrics from the customer perspective.

Throughout the engagement process, customers expressed support for retaining the definitions of vulnerable populations as “distribution-constrained customers” and “energy-burdened customers.” These definitions are detailed in the CEIP document. Additionally, customers emphasized the need for expanded programmatic support for non-homeowner groups within the energy-burdened category, while affirming that the overall definition remained appropriate.

Appendix D.

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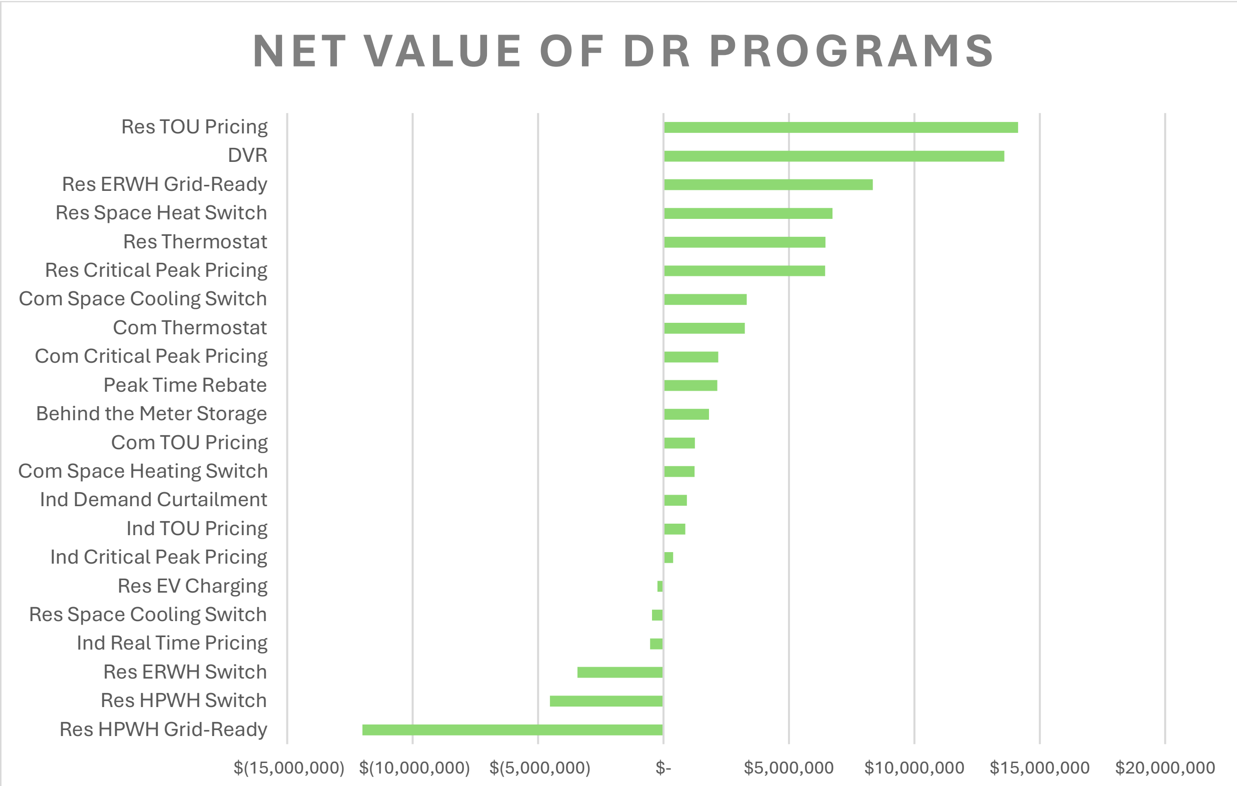
Appendix E. Demand Response Value Analysis

The DRPA included 22 demand response (DR) programs for consideration in the 2025 IRP, with 16 of these were found cost-effective to develop. A significant change from the 2023 Update is that DR programs now have two primary value streams. The traditional driver of value comes from capacity value - a reduction in load during peak hours which reduces the monthly peak demand bill. With recent legislative changes, demand response programs now additionally generate value by creating REC equivalents to meet annual EIA regulatory compliance targets. Staff estimate that the regulatory value could represent 60-70% of the net value from DR.

The net value is not equal among all cost-effective DR programs. Out of the 16 that are found to be cost-effective, the top 3 programs are estimated to provide half of the total net value. The Residential Time of Use rate was found to bring the most value, with the second being Demand Voltage Reduction. There is also a clear trend between program value and program customer type, with most of the highest-value DR being residential programs, mid-value being commercial, and the lowest-value being industrial programs. These are largely aligned with expectations based on the PUD's customer base primarily being residential and smart rate options having fewer program costs than device-based programs. Demand Voltage Reduction represents a unique program based on utility actions without relying on customers.

Figure E - 1 Program Net Value



Capacity value

With the Load-Following product, BPA's capacity pricing is based on a demand charge applied to the highest measured hourly load in every month. This incentivizes the PUD to reduce its peak monthly load if it is more cost-effective than BPA's demand charge to reduce the net peak costs. DR programs provide capacity value by reducing the PUD's demand charge exposure. A DR program must successfully bring down the month's highest hourly load to provide this capacity value. Out of the 16 programs found cost effective, 10 were cost-effective through capacity value alone without including regulatory value. High-cost DR and those with an estimated low net value are those that are not expected to be cost effective through capacity value alone. The DR that is found to be highly cost-effective through capacity value alone may be considered as having the least risk from a cost perspective. Not considered in this analysis is the capability to reduce peak hour demands, instead all programs were given their full capacity for all months. The ability to call rely on called customer programs has diminishing returns and forecast errors in predicting peak hours will degrade program capabilities depending on the program.

Regulatory value

The passage of Washington State's Senate Bill 5445 provides a significant new incentive to procure DR by generating equivalent RECs to meet the PUD's compliance targets in accordance with the Energy Independence Act. The amount of regulatory value DR programs produce is based on the amount of the PUD's peak system load the DR program could reduce, as shown in Section 3.

The conversion of capacity to RECs uses the DR power capacity to meet the peak needs and this is converted to MWhs through annual system load which are equivalent to RECs for meeting EIA requirements. The claimed capacity of the DR programs must be verified through measurement and verification. The biggest difference with this value stream is that it comes from annual peak load reduction capability while the capacity value comes from actual monthly peak load reduction.

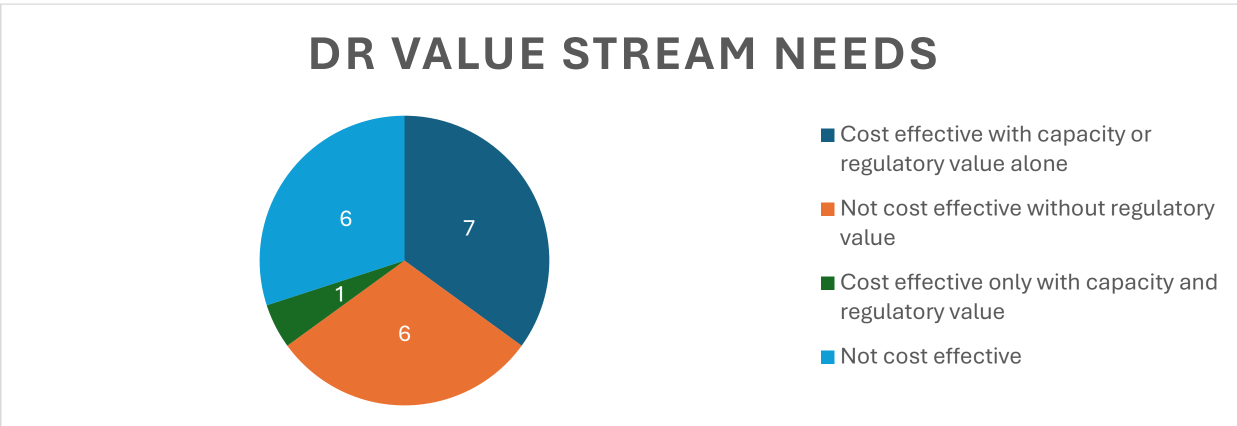
The amount of regulatory value received through the DR is dependent on the price of the RECs that would have otherwise been purchased in compliance with the Energy Independence Act. It is also dependent on how DR capacity against peak system load is counted; if the bill uses the maximum capacity of a DR program in any part of the year against the system peak, summer-peaking DR will benefit. If the bill only takes the maximum capacity of DR during the same period as system peak, winter-focused DR will benefit from the bill and summer peaking programs will be disadvantaged, even if the PUD load is close to being dual-peaking since annual peak loads will be during the winter for the foreseeable future.

Other considerations

Outside of the benefit in bringing energy and regulatory costs down for customers, other strongly considered aspects of DR program development include administrative feasibility, customer education and customer interest. The difficulty of establishing a program from an administrative perspective should factor in feasibility. Some DR programs require several steps to deploy, including appliance retrofits and contractor involvement, while others, such as smart rates, are lower cost and offer more flexibility for customers. Several DR programs have been chosen as the most feasible to deploy from staff perspectives of administrative feasibility and customer interest. Additionally, staff perspective on customer appetite for programs suggests that a large menu of items may be confusing from a customer perspective, so DR deployment should start with a small number of high value programs.

DR program development should seek to maximize both regulatory and capacity value. Since regulatory value may prove to provide the majority of the monetary net benefit of DR programs, it is important to optimize for this new aspect. Programs that are cost-effective based on capacity value alone may have the most durable value to the PUD, carrying less policy risk. Programs that are not found to be cost-effective without SB5445 should be carefully considered and programs that require both regulatory and capacity value should have additional due diligence performed before allocating resources.

Figure E - 2 DR Program Value Stream Requirements



Appendix F. Emerging Technologies

The purpose of this appendix is to examine and describe various supply-side generation and capacity resource technologies that did not make it into the body of the PUD's 2025 IRP. These technologies usually need more time to mature and become commercially available in and around our greater geographic region at a price point that is reasonably competitive with existing alternatives that meet similar needs. Each technology listed is categorized into either generation or capacity resources.

Generation

Offshore Wind

Offshore wind resources typically have higher speeds and less variability than land-based winds, and offshore wind turbines have grown in popularity to capture the vast amount of kinetic energy that comes from the ocean winds.[i] The turbines' placement in the ocean allows them to be very large, with their average hub height (water line to rotor) expected to reach 500 feet, and a higher average capacity factor than onshore turbines, at 43% against 34%.[ii] However, they require special design and infrastructure due to the complexities of being offshore. Offshore wind has been included in the last 5 years of the IRP's High-Tech scenario assuming technological development facilitates this resource type.

Offshore turbines can be divided into two types: fixed-bottom and floating. Fixed-bottom turbines are connected to fixed structures which are embedded into the ocean floor. Above water, fixed-bottom turbines are nearly identical to onshore turbines, except that they are marinized for oceanic conditions and their power capacity tends to be far greater than a typical onshore turbine due to their greater size and the stronger winds. Almost all operational offshore turbines are fixed-bottom. The greatest constraint with fixed-bottom turbines is that they can usually only be in water up to around 200 feet deep, making them not applicable to the Pacific Coast, which requires turbines to be at a greater water depth.[iii]

Floating turbines are a newer design where the turbines float on the water, attached to floating foundations which are then connected to mooring lines. Floating turbines can be installed in deep water, allowing them access to far more offshore wind resources than fixed-bottom turbines. They may also have a smaller environmental effect on the surrounding marine ecosystem due to their farther proximity from the coast and reduced environmental disturbance during installation.[iv] However, because of the lack of currently operating floating turbines, research and continued monitoring of the existing floating projects is needed to fully assess the environmental impact.

As of 2025, there are no offshore wind projects operating in the Western U.S., but several in Rhode Island, Massachusetts and Virginia. More than 6GW offshore capacity is planned in mostly the East Coast.[v] Higher costs associated with the complexities of offshore installation, maintenance and transmission can impact the economic feasibility of offshore wind resources. Some of the biggest risks can be attributed to undersea power cables, including array cables, which transfer the generated electricity from the turbines to the offshore substations, and export cables, which connect the power from the substations to the onshore grid. More than 80% of financial losses and insurance claims in the offshore wind industry are caused by power cable failures, which usually take 1-2 months to repair.[vi] Both operational and environmental risks related to undersea cables should be minimized through continued research and development, new technologies and a strong regulatory framework. Site location must be carefully considered based on marine coastal ecosystem impact and visual disturbances. An action plan by the Department of Energy was released in 2025 to address the necessary transmission development for offshore power on the West Coast, as an expanded transmission network, coordinated planning and technological advancements are all necessary to support the development of floating turbines in the Pacific Region.[vii] As the permitting process streamlines, and the cost of infrastructure, construction, and operations continue to decline, offshore wind turbines have the potential to become commercially available in the Western U.S.

Enhanced Geothermal Systems

While natural geothermal reservoirs require specific geological conditions like heat, fluids, and permeable rock, Enhanced Geothermal Systems (EGS) only need underground heat, as they can artificially create geothermal reservoirs through technologies such as hydraulic fracturing and fluid injections. Like traditional geothermal systems, EGS pump water through the fracture networks, which then heat a working fluid above-ground to spin a turbine. The first operating EGS project was installed in New Mexico, US in the early 1970s.[viii] There have since been many EGS projects around the world, with 3 project pilots funded by the DOE in Oregon, Northern California and Utah.[ix] The Utah project is planned to provide up to 2GW of power.[x]

Unlike many renewable resources, geothermal generators provide steady baseload power, which adds value to their production. There is a considerable amount of underground heat resource in the Western U.S. which is suitable for EGS, and some organizations are performing analyses on potential sites in the Cascade Mountain Range. There have been concerns over the risks of induced seismicity that can be caused by the fracturing process, the heavy amount of water EGS consume, and water contamination risks. Water contamination risks are considered low since EGS operate extremely deep, below and away from any drinking source, and with usually benign fluid.[xi] EGS operate through a closed-loop system, so geothermal fluid is kept inside a well casing and not deposited onto the surface. Ongoing research and development continue to optimize fluid flow, economize the wellbore and drilling process, and reduce the risk of induced seismicity. As costs are reduced and technology improves, EGS may be explored further as a viable renewable baseload resource.

Hydrogen Turbines

Hydrogen gas has the potential to be used as fuel for peaking power plant turbines. Peaking power plants ("Peakers") are generators with relatively low fixed costs and high variable costs which can be quickly dispatched to meet peak demand hours. Peaking power plants are usually fueled with natural gas, although some generators use other fuels like oil. These Peakers can be retrofitted to be Hydrogen-capable, using 100% hydrogen to fire the plant instead of natural gas. Hydrogen does not emit pollutants and can be produced using nonpolluting energy. Many current retrofitted Peakers cofire natural gas with a mix of 5%-20% hydrogen, usually with a goal of reaching 100% hydrogen in the future. The conversion of a natural gas Peaker plant requires an upgrade of the fuel injection, combustion systems and burners to handle hydrogen gas. Hydrogen-fired turbines with onsite hydrogen production may also be considered a capacity resource, with hydrogen being stored onsite and the turbine used to discharge the stored energy.

The primary barrier to feasibility for fully hydrogen-fired turbines is the cost of green hydrogen production and the necessary storage and/or delivery infrastructure. Hydrogen made from renewable energy through electrolysis is not yet offered at a competitive price. The hydrogen can either be produced and stored onsite or transported either through trucking or through pipeline systems. Their development must also navigate permitting and policy frameworks that are not specific to hydrogen. Washington State released a June 2025 Green Hydrogen Programmatic EIS to help streamline their environmental reviews,[xii] but permitting is still on a case-by-case basis and policy infrastructure for hydrogen is still in the process of being made. Because hydrogen burns at a higher temperature than methane, hydrogen turbines can release a high amount of nitrogen oxide, which may require further modifications depending on regulatory requirements.[xiii] Key policy support and local regional efforts to bring down prices and implement a hydrogen hub, combined with a comparatively low cost of electricity in the Pacific Northwest, may help hydrogen turbines to be a viable resource to address peak demand in the future. However, capacity resources such as lithium batteries are currently a more economic option to address peak demand.

Ocean Energy

Ocean energy generators harness energy from tidal forces, wind waves, and temperature differences in the ocean. Ocean thermal energy systems are most effective in tropical locations and therefore are not applicable in the local region. The other two primary ocean energy systems are tidal and wave power.

Tidal power generation can be divided by tidal stream and tidal barrage systems. Tidal stream systems use a turbine, usually underwater, in the location of fast flowing currents. They are very similar to wind turbines, using blades that capture kinetic energy to then turn a rotor. Tidal barrage systems use barrages, which are dams, across enclosed bays, inlets, or rivers. They are more like hydropower plants as they take advantage of changes in sea level. As the tide comes in, potential energy is held behind the dam. Water is then released through a turbine which generates power.

Wave power systems, usually called wave energy converters (WEC), generate energy captured by waves, and typically float on top of the ocean. To date, WEC only generate around 20MW worldwide. Around 96% of all installed ocean energy capacity comes from the 254MW Sihwa Lake tidal barrage in South Korea, and the 240MW La Rance tidal barrage in France. Tidal stream and WEC technologies are still in their infancy, and as research progresses, they will likely take a larger share of the installed ocean energy capacity.

The predictability of tidal energy offers an advantage against other renewable resources such as the sun and wind, which generally cannot be forecasted as accurately. While wave resources are not quite as predictable, since the waves come mostly from wind, the Pacific Northwest has been assessed by several organizations and ranked highly for wave power potential. Because water is around 800 times denser than air, tidal stream turbines do not need to be as large as wind turbines to generate an equivalent amount of power and therefore can be constructed in smaller sizes.

There can be environmental concerns as ocean energy systems have the potential to cause harm to the surrounding ecosystems. Underwater turbines can impact marine wildlife, and their placement can cause disruptions to the seabed and migration patterns of both marine animals and birds.[xiv] Tidal barrages especially require consideration of environmental impact due to the system damming an inlet, which can lead to an array of ecosystem changes due to the change in tidal flow and saltwater concentration within. Underwater turbines and infrastructure are also subject to heavy corrosion due to saltwater and potentially strong tidal streams, which means that the turbines need to be engineered to withstand far harsher environmental conditions than a wind turbine. Because of this, the cost of construction and maintenance are not economically competitive.

CCS Natural Gas

Carbon Capture, Utilization and Storage (CCUS) or Carbon Capture and Storage (CCS) are technologies that capture CO2 gases from an emitting source. The CO2 is either stored in a deep geological reservoir or transported to an off taker and reused for industrial manufacturing. CCS natural gas turbines mitigate a percentage of the CO2 emissions from their smokestack, usually targeted at 90%.[xv] The PUD has no emitting resources in its portfolio and does not plan to add any natural gas resources to its portfolio in the future. However, CCS natural gas turbines may be a future option for other utilities in the region. While carbon capture technology has existed since the 1920s, as of 2025 there are not yet any currently operating CCS natural gas electrical generating plants.

CCS natural gas plants have the benefits of a combined-cycle gas plant, including the reliability benefit of dispatching on-demand and the ability to quickly ramp up power to meet peak needs. In contrast, intermittent renewable resources like solar and wind cannot generate electricity on demand or ramp up generation during peak hours. For utilities that already have natural gas infrastructure, combined-cycle gas plants with carbon capture technology may prove to be an economical way to meet their customers' energy needs while reducing carbon emissions and meeting state regulatory compliance targets.

While the standard target carbon capture rate for CCS natural gas plants is around 90%, studies show that reaching levels of up to 99% may include low or no additional marginal cost.[xvi] However, capture rates of 98% or higher do usually require more equipment and energy.[xvii] CCS natural gas plants carry compliance risk in this region, given CETA's requirement for Washington State utilities to not have any non-emitting resources by 2045. There are also permitting complications with the construction of a natural gas plant in Washington State, the carbon capture monitoring and verification, and the geological sequestration. Additionally, CCS natural gas plant generating costs are subject to the price of natural gas. CCS natural gas plants have reliability benefits and a strong ability to ramp up during peak demand, however the permitting complications, compliance risks and the necessary infrastructure as well as geological siting make CCS natural gas plants a resource choice that is particularly difficult for any utility in the state to consider.

Capacity Resources

Flywheel Energy Storage Systems

Flywheel Energy Storage Systems (FESS) store energy through a rotating flywheel powered by a motor/generator that spins at very high speeds. FESS convert electrical energy into mechanical energy for storage, captured through the acceleration of the flywheel. FESS can then dispatch energy through the flywheel's conversion back to electrical energy, resulting in deceleration of the flywheel. There are several 20MW FESS operating under utilities in the U.S., including New York and Pennsylvania and a planned project in California, as well as a 30MW FESS operating in China.

FESS have incredibly long lifespans while requiring minimal maintenance, and when they have magnetic bearings, they have a very high roundtrip efficiency at up to ~90%. They can also be charged and dispatched rapidly, with both a high power and energy density. The components of a FESS consist of mainly steel and magnets, which makes their permitting process and code compliance easier than a lithium-ion BESS development because of the low fire risk, lack of hazardous materials and low environmental impact. Their decommissioning process is also simpler, as the facilities can usually be fully recyclable at the end of their lifecycle. Flywheel storage systems can also operate under extreme temperatures (-40C to 50C) and humidity, and do not experience battery degradation, reducing the variability of the cost of their operations and maintenance. Flywheel systems usually have high ramp rates and short durations, making them best suited for grid frequency regulation and not optimal for long-duration capacity needs. While the planned project in California will have a 4-hour duration at 20MW, many are limited to 1 hour.[xviii] Flywheel storage systems offer distinct advantages over other forms of storage, but they are not yet economically competitive with lithium storage systems as a grid capacity resource.

Liquid Air Energy Storage

Liquid Air Energy Storage (LAES) is a type of cryogenic energy storage in which air is captured, cleaned, dried, and cooled to -196C, liquifying the gas into a cryogenic fluid that is ~710 times denser than air in a gas state. To discharge back into electricity, the liquid air is then warmed back into a gas and driven through a turbine. LAES company Highview Power is constructing a 300MWh project in Manchester, UK, and Tacoma Power, partnered with Praxair, announced a plan to build a 450MWh project in Washington State.

Liquifying gases through the Claude Cycle is not a new process and is used in many industrial cases. An advantage to liquid air storage is that the facilities do not need special geologic conditions, as they do not need very much area due to the density of the liquified air. However, the roundtrip efficiency of a liquid air storage system is only around 25%, which strongly affects the system's economic viability since fuel is a primary cost driver. A low roundtrip efficiency means the compressors, which are energy intensive, must be used more often. Some developers claim that LAES could be capable of potentially reaching up to 70% roundtrip efficiency if both cold and waste heat are captured. LAES are not yet commonly commercially available, and further development is needed for the liquid air storage systems to reach higher efficiency and lower overall costs. There are not yet any operating utility-scale commercial liquid air storage systems.

Nickel Hydrogen Batteries

Rechargeable nickel-hydrogen batteries store energy using nickel-hydroxide and hydrogen gas. These batteries first store hydrogen gas in a pressurized container, and upon discharge, hydrogen reacts with nickel-hydroxide to produce electricity. Upon recharging, hydrogen is regenerated. Nickel-hydrogen batteries are most used in aerospace, with NASA implementing them in satellites since 1970s,[xix] including the James Webb Telescope. The California-based company Enervenue is pilot testing utility-scale nickel-hydrogen batteries in Milwaukee.

The potential for this battery technology has expanded into grid-scale storage due to their extreme durability, long lifespan and fire safety. They can last up to 30,000 cycles and 30 years, are 100% recyclable, and have no thermal runaway risk.[xx] While they are projected to be more expensive than lithium-ion batteries per unit of energy, some studies show nickel-hydrogen energy storage systems to be more economic due to their long lifespan and simple maintenance needs. There are no currently operating nickel-hydrogen battery storage systems, and their deployment onto the grid will shed better light on their feasibility.

Flow Batteries

Redox Flow Batteries (RFB), also called Flow Batteries, use liquid electrolytes which are pumped through two tanks separated by a membrane. One tank has negative electrolytes while the other has positive electrolytes, and electrons are transferred from one tank releasing the electrons through oxidation, and the other tank gaining the electrons through reduction. The most popular type of redox flow batteries use vanadium, called Vanadium Redox Flow Batteries (VRFB), which are seen as the most promising due to their ability to exist in four different oxidation states as well as their lifespan, environmental and safety benefits.[xxi] There are several currently operating redox flow batteries, with the largest being a 200MW VRFB in China, completed in 2025.

RFBs have more flexibility in scaling their storage and power separately, since increasing capacity only takes larger tanks and increasing power takes increasing the size of the reactor.[xxii] For this reason, RFBs are easier to scale up in capacity. VRFBs can also discharge for up to 12 hours at a time, can be brought to full power very quickly, and have a wide operating temperature range.[xxiii] However, RFBs have low energy density and are not a mature enough technology to be cost competitive with lithium batteries at grid-scale. It’s very possible that with further technological improvements to bring down costs, given their distinct benefits, RFBs may become a competitive grid-scale storage product.

Sodium Ion Batteries

Sodium-ion batteries (NIB) can be like lithium-ion batteries, except instead of lithium-ions they use sodium-ions, with sodium being a less expensive and easier to source element. When charging, sodium ions move from the sodium-based cathode to an anode, with the reverse happening upon discharge. An increase in the price of lithium salts led to increased interest in sodium-ion battery technology in the early 2020s, although sodium batteries have been in development for more than 50 years. There is one company in the United States with a currently operating sodium-ion grid-scale battery, being a 3.5MWh pilot project by Peak Energy constructed in 2025.[xxiv] The largest sodium-ion storage system is a 50MW project located in China and was constructed in 2024.[xxv]

The biggest advantage that sodium-ion batteries have over the standard lithium-based batteries is the accessibility to sodium. Sodium is one of the most abundant elements in the world, while lithium is not naturally abundant.[xxvi] However, sodium-ion batteries tend to have a lower energy density than their lithium-ion competitor and still experience a higher cost per unit of energy stored than lithium-ion storage.[xxvii] Sodium-ion batteries may offer some unique advantages over other forms of storage, with Peak Energy's piloted battery operating under a wide temperature range and requiring no chiller or HVAC, more than a 20 year lifespan, and claiming more than a 95% roundtrip efficiency.[xxviii] Large-scale sodium-ion batteries have not yet been commercialized in the United States, but their popularity may increase if supply chain concerns for lithium-ion storage systems grow.

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