SNOHOMISH COUNTY PUBLIC UTILITY DISTRICT
BOARD OF COMMISSIONERS REGULAR MEETING
Everett Headquarters Building, 2320 California Street
Zoom Online Platform Option Available

December 2, 2025

CONVENE REGULAR MEETING – 9:00 a.m. – Commission Meeting Room

Virtual Meeting Participation Information

Join Zoom Meeting:

- Use link https://us06web.zoom.us/j/84041836214?pwd=cz7aeX8POeKXpJWJ42tzjNKJp8sJMx.1
- Dial in: (253) 215-8782
- Meeting ID: 840 4183 6214
- Passcode: 799585

1. **RECOGNITION/DECLARATIONS**
   A. Employee of the Month for December – Laura Lemke

2. **COMMENTS FROM THE PUBLIC**
   If you are attending the meeting virtually (using the link or number provided above) please indicate that you would like to speak by clicking "raise hand" and the Board President will call on attendees to speak at the appropriate time. If you are joining by phone, dial *9 to "raise hand."

3. **CONSENT AGENDA**
   A. Approval of Minutes for the Regular Meeting of November 18, 2025
   B. Bid Awards, Professional Services Contracts and Amendments
   C. Consideration of Certification/Ratification and Approval of District Checks and Vouchers

4. **CEO/GENERAL MANAGER BRIEFING AND STUDY SESSION**
   A. Updates
      1. Other
   B. Purchase of Property for Future 115kV Ring Bus
   C. Connect Up Quarterly Update
   D. Audit Activity Update
   E. Water Supply Update
   F. Energy Risk Management Report

Continued →

5. **CEO/GENERAL MANAGER REPORT**

6. **PUBLIC HEARING**
   A. Public Hearing on Proposed 2025 Integrated Resource Plan
   B. Public Hearing on Proposed 2025 Clean Energy Implementation Plan
   C. Public Hearing on Proposed 2026-2027 Biennial Conservation Targets and Ten-Year Conservation Potential Estimate

7. **PUBLIC HEARING AND ACTION**
   A. Consideration of a Resolution Adopting the 2026 Budget for Public Utility District No. 1 of Snohomish County, Washington
   B. Consideration of a Resolution Amending the District's Water Service Rates and Charges for Single Family, Multiple Family, and Commercial/Industrial Customers for Water Utility Service
   C. Consideration of a Resolution Approving Increased Fees Payable by Licensees of Space on District Utility Poles
   D. Consideration of a Resolution Amending the District's Retail Electric and Street Lighting Service Schedules

8. **ITEMS FOR INDIVIDUAL CONSIDERATION**
   A. Consideration of a Motion Accepting the Financial Planning and Budgeting Monitoring Report
   B. Consideration of a Resolution Authorizing the Chief Operating and Legal Officer of Public Utility District No. 1 of Snohomish County to Execute an Aquatic Lands Lease With the Washington State Department of Natural Resources Concerning the Hat Island Submarine Cable Project
   C. Consideration of a Resolution Authorizing the CEO/General Manager of Public Utility District No. 1 of Snohomish County to Execute an Amendment to an Interlocal Agreement With the City of Everett and Ratifying an Amendment to a Grant Agreement With the Washington State Department of Commerce, all Regarding the Purchase, Installation and use of a Charging System for Electric Buses at College Station at Everett Community College

9. **COMMISSION BUSINESS**
   A. Commission Reports
   B. Commissioner Event Calendar
   C. 2025 Treasury, Budget, and Project Status Report - October
   D. Consideration of Election of Commission Officers for the Year 2026

10. **GOVERNANCE PLANNING CALENDAR**
    A. Governance Planning Calendar
    B. Proposed 2026 Governance Planning Calendar

Continued →

ADJOURNMENT

December 10, 2025:

Economic Alliance of Snohomish County (EASC) Legislative Kickoff – Everett WA
9:00 a.m. – 11:00 a.m.

The next scheduled regular meeting is December 16, 2025

Agendas can be found in their entirety on the Snohomish County Public Utility District No. 1 web page at www.snopud.com. For additional information contact the Commission Office at 425.783.8611

BUSINESS OF THE COMMISSION

Meeting Date: December 2, 2025 **Agenda Item:** 1A

TITLE

Employee of the Month for December – Laura Lemke

SUBMITTED FOR: Recognition/Declarations

Human Resources	Traci Brumbaugh	8626
Department	*Contact*	*Extension*

Date of Previous Briefing: _____

Estimated Expenditure: _____ Presentation Planned ☒

ACTION REQUIRED:

☐ Decision Preparation
- ☐ Policy Discussion
- ☐ Policy Decision
- ☐ Statutory

☒ Incidental (Information)

☐ Monitoring Report

SUMMARY STATEMENT:

Identify the relevant Board policies and impacts:

Laura Lemke joined Snohomish County PUD in 2008 and has steadily advanced through roles in energy efficiency, analytics, and strategy. She currently serves as a Program Director in the Government Relations and Strategy department, where she leads development and execution of our strategic plan, drives initiatives to improve organizational performance, and facilitates the ELT's monthly Business Review Meeting.

Laura's dedication has earned her multiple recognitions, including Employee of the Month in December 2014. She's also contributed as a key member of award-winning teams, such as the Incident Management Team (November 2020) and Bill Estimation Team (March 2021). She served as a mentor in the Western Energy Institute's Business Acumen for Emerging Leaders in 2021 and 2022. Known for her collaborative spirit, proactive problem-solving, and ability to connect teams across divisions, Laura's work consistently strengthens the District and enhances service for customers and colleagues alike.

Laura will be presented by Kim Johnston, Chief Government Relations & Strategy Officer.

List Attachments:
Employee Profile

Meet Laura Lemke, Our December Employee of the Month

Every organization needs to have a good plan.

The PUD has spent several years crafting its Strategic Plan to help ensure we are serving our communities while remaining as prepared as possible for what the future may bring. It's important for the PUD to be forward-thinking and looking ahead as we continue to build a sustainable future and bolster operational reliability and resiliency.

Fortunately, we have future planning luminary Laura Lemke.

Laura, a Program Director in Government and External Affairs, has been hard at work for the past several years trying to map out the next 15-20 years (and beyond). Through working with groups across the PUD to develop the Strategic Plan and future scenario planning, Laura has helped ensure that the PUD is ready to continue energizing life in our communities.

For all her work that she does to help develop, strengthen and help groups stay on track for the future, Laura has been named the PUD's December Employee of the Month.

"The thing I want to emphasize about Laura is that she sets a really high bar for herself, for the team, for the Executive Leadership Team and for the organization," said Kim Johnston, Chief Government Relations and Strategy Officer. "Then, she does everything she can to help us live up to those high expectations. She's a really skilled human at being able to get into the weeds and create a dashboard with data, but then also tell a story about it."

Kim remembers the first time she heard Laura present to the Executive Leadership Team. Almost immediately, she began trying to figure out how she could get Laura on her team.

"The first time I saw Laura in action she came in and rolled out this loose plan of what a Strategic Planning process could look like for the organization," Kim said. "She instantly made an impression on me. I was so excited. She brought this passion into the room. I was like, How can I get her on my team so that we can work together?"

Originally on the Data & Analytics team before that fateful ELT meeting, Laura has been at the PUD for over 17 years. After shepherding the PUD through the Strategic Planning process, Laura has continued to help workgroups make sure they are measuring the right information and staying on track so that the PUD can meet its goals and ensure that its priorities and initiatives are considered and accomplished.

"When work started on the current Strategic Plan you could feel a collective groan around the PUD," one of Laura's co-workers at the PUD said. "Those that had been around for a while were sure this would be just another document collecting dust on a shelf. Through immeasurable effort, a commitment to collaboration and pure tenacity, Laura was able to lead an effort that included a myriad of voices from across the PUD and resulted in a living document. Work at the PUD now

feels more strategic, more collaborative, and less siloed than before and I think that Laura's leadership of the process was integral to that outcome."

"Her work goes far beyond the Strategic Plan," Kim added, "but I also don't want to lose the fact that she's done an incredible job creating a process for us to really have a high-impact strategic plan and implement that plan across the organization."

Kim said Laura is a very social person and a really good communicator. Laura is known to love a whiteboard and a good brainstorming session.

"Laura has been instrumental in driving both large and small projects across the PUD," said Hillary Olson, Program Manager, Strategic Accounts. "Her extensive knowledge enables her to effortlessly connect different areas of the PUD, fostering coordination and collaboration across often siloed divisions."

"Laura has truly become my 'go to' at the PUD," another PUD employee said. "Whenever I need to share an idea, seek guidance, or get feedback on anything, whether it's a presentation, document, an email, or a new procedure, she's one of the first people I turn to. Her depth of knowledge is remarkable, and what I value most is her honesty and candor. Laura doesn't just give feedback; she offers thoughtful, thorough insights."

Demonstrating her commitment to a variety of programs at the PUD, Laura is also a Chair for the Women Empowered at Snohomish PUD and was instrumental in the relaunch of the employee resource group last year.

"There are too many things Laura has done to make this a better workplace," a PUD employee said. "She is the board chair for Women Empowered. Through her organization and drive, she was instrumental in establishing this group and helping to make it even better. They have achieved success in bringing a broad range of employees together to encourage growth and opportunities."

Laura was born in Chicago and grew up on a small farm outside of Minneapolis in Wayzata, Minnesota. She started her career in the mason industry, handling marketing and web design for Mutual Materials in Bellevue. After working in marketing communication and strategy roles with Callison Design (now CallisonRTKL) and Intermec (now Honeywell), Laura joined the PUD in 2008.

Her favorite part of her work is that she gets to interact with teams across the PUD and loves getting to understand the various aspects of what Team PUD does. Not surprisingly, outside of the Strategic Plan, one of her favorite projects came in her Data and Analytics days when Power BI was adopted as the PUD's analytics and dashboard platform.

Laura loves speaking with all of the departments around the PUD about their goals and data and wanted to extend her sincere thanks for the Employee of the Month award.

“Thank you for this honor. I appreciate each and every one of you and the work you do,” Laura said. “You humor my curiosity and questions to understand how it all works. Your dedication to our customers and communities and our shared mission is inspiring and makes me want to get up and do it all over again every day.”

COMMENTS FROM THE PUBLIC

BUSINESS OF THE COMMISSION

Meeting Date: December 2, 2025 **Agenda Item:** 3A

TITLE

Approval of the Minutes for Regular Meeting of November 18, 2025

SUBMITTED FOR: Consent Agenda

Commission	Allison Morrison	8037
Department	*Contact*	*Extension*

Date of Previous Briefing: _____

Estimated Expenditure: _____ Presentation Planned ☐

ACTION REQUIRED:

☐ Decision Preparation
- ☐ Policy Discussion
- ☐ Policy Decision
- ☒ Statutory

☐ Incidental (Information)

☐ Monitoring Report

SUMMARY STATEMENT:

Identify the relevant Board policies and impacts:

Governance Process, Board Job Description: GP-3(4) … a non-delegable, statutorily assigned Board duty as defined under RCW 54.12.090 – minutes.

List Attachments:

Preliminary Minutes

PRELIMINARY
SNOHOMISH COUNTY PUBLIC UTILITY DISTRICT

Regular Meeting **November 18, 2025**

The Regular Meeting was convened by President Sidney Logan at 9:00 a.m. Those attending were Tanya Olson, Vice-President; Julieta Altamirano-Crosby, Secretary (virtually); Chief Communications Officer Lisa Hunnewell; Chief Operating & Legal Officer Colin Willenbrock; other District staff; members of the public; Clerk of the Board Allison Morrison; and Deputy Clerks of the Board Jenny Rich and Morgan Stoltzner.

*** Items Taken Out of Order**
****Non-Agenda Items**

1. COMMENTS FROM THE PUBLIC

There were no comments from the public.

2. CONSENT AGENDA

A. Approval of Minutes for the Regular Meeting of November 4, 2025

B. Bid Awards, Professional Services Contracts and Amendments

Public Works Contract Award Recommendations:
None
Formal Bid Award Recommendations $120,000 and Over:
None
Professional Services Contract Award Recommendations $200,000 and Over:
None
Miscellaneous Contract Award Recommendations $200,000 and Over:
Miscellaneous Contract No. CW2260162 with United Cascade Enterprises Inc. dba Cascade Energy LLC
Miscellaneous Contract No. 4500101774 with DLT Solutions LLC
Interlocal Agreements and Cooperative Purchase Recommendations:
Contracts:
Purchase Order No. 4500101900 with Frontier Technology dba MicroAge
Purchase Order No. 4500101905 with Global Rentals Company
Amendments:
None
Sole Source Purchase Recommendations:
None
Emergency Declarations, Purchases and Public Works Contracts:
None
Purchases Involving Special Facilities or Market Condition Recommendations:
None
Formal Bid and Contract Amendments:

Miscellaneous Contract No. CW2223266 with Proofpoint, Inc.
Professional Services Contract No. CW2243088 with Van Ness Feldman, LLP
Professional Services Contract No. CW2246601 with Li Immigration Law PLLC
Professional Services Contract No. CW2246791 with Snohomish County Council of the Society of St. Vincent De Paul
Professional Services Contract No. CW2253913 with Marian Dacca Public Affairs LLC
Contract Acceptance Recommendations:
Public Works Contract No. CW2257829 with Davey Tree Surgery Company
Public Works Contract No. CW2258633 with Davey Tree Surgery Company
Public Works Contract No. CW2258980 with B & L Utility, Inc.

C. Consideration of Certification/Ratification and Approval of District Checks and Vouchers

A motion unanimously passed approving Agenda Items 2A – Approval of Minutes for the Regular Meeting of November 4, 2025; 2B – Bid Awards, Professional Services Contracts and Amendments; and 2C – Consideration of Certification/Ratification and Approval of District Checks and Vouchers.

3. CEO/GENERAL MANAGER BRIEFING AND STUDY SESSION

A. Updates

1. Strategic Plan Quarterly Update. There were no questions on the Strategic Plan Quarterly Update.

2. Other. There were no other updates

B. Project Scope and Interlocal Agreement Amendment With Everett Transit

Program Manager Suzy Oversvee introduced Everett Transit Director Michael Schmeider and provided a presentation to the Board on the Everett Transit project and interlocal agreement amendment. Information included Partner Agreements, Roles and Responsibilities, Project Background and the Change in Scope.

Commissioner Altamirano-Crosby asked if the site can be visited. Program Manager Suzy Oversvee responded that the site should be available for visits in Q1 2026.

The next step would be to return at the December 2, 2025, Commission meeting for consideration of a resolution.

4. CEO/GENERAL MANAGER REPORT

Chief Communications Officer Lisa Hunnewell and Chief Energy Resources Officer Jason Zyskowski reported on District related topics and accomplishments.

5. PUBLIC HEARING

A. Continue Public Hearing on the 2026 Proposed Budget

President Logan reconvened the public hearing.

Senior Manager, Budget and Financial Planning Sara Bond provided a presentation continuing the discussion of the proposed changes and amendments to the proposed 2026 budget.

The 2026 proposed Budget remaining hearing schedule was as follows:

December 2, 2025:
Request Approval of the 2026 Budget

There were no public comments.

A motion unanimously passed continuing the hearing on the 2026 Proposed Budget to Tuesday, December 2, 2025, at 9:00 a.m., at 2320 California Street in Everett, WA.

B. Continue Public Hearing on the Proposed Revision to the District's General Retail Rates for Water Utility Services

President Logan reconvened the public hearing.

There were no public comments.

A motion unanimously passed continuing the hearing on the Proposed Revision to the District's General Retail Rates for Water Utility Services to Tuesday, December 2, 2025, at 9:00 a.m., at 2320 California Street in Everett, WA.

C. Public Hearing for Approving Increased Fees Payable by Licensees of Space on District Utility Poles

President Logan convened the public hearing.

There were no public comments.

A motion unanimously passed continuing the hearing on Approving Increased Fees Payable by Licensees of Space on District Utility Poles to Tuesday, December 2, 2025, at 9:00 a.m., at 2320 California Street in Everett, WA.

D. Public Hearing on Adjustments to the District's Residential, Commercial, and Industrial Rate Schedules

President Logan convened the public hearing.

Chief Energy Resources Officer Jason Zyskowski and Senior Manager Rates, Economics and Energy Risk Management Peter Dauenhauer provided a presentation on the adjustments to the District's Residential, Commercial, and Industrial rate schedules.

Commission Olson requested information on if the conservation and energy efficiency work being done are fixed charges. Senior Manager Rates, Economics and Energy Risk Management Peter Dauenhauer stated he will confirm that and have it sent to the Board.

Commissioners Olson and Logan discussed the possibility of holding a workshop focused on rate processes and Board philosophy, with the goal of ensuring alignment between the two.

A motion unanimously passed continuing the hearing on the Adjustments to the District's Residential, Commercial, and Industrial Rate Schedules to Tuesday, December 2, 2025, at 9:00 a.m., at 2320 California Street in Everett, WA.

6. ITEMS FOR INDIVIDUAL CONSIDERATION

A. Consideration of a Resolution Adopting a Plan or System of Additions to and Extensions of the District's Water Utility; Declaring the Intention of the Board of Commissioners to Form Water Local Utility District No. 68 to Carry out That Plan; and Fixing the Date, Time and Place for a Public Hearing on Formation of the Proposed Local Utility District and Confirmation of the Assessment Roll

A motion unanimously passed approving Resolution No. 6254 Adopting a plan or system of additions to and extensions of the District's Water Utility; declaring the intention of the Board of Commissioners to form Water Local Utility District No. 68 to carry out that plan and fixing the date, time and place for a public hearing on formation of the proposed Local Utility District and confirmation of the assessment roll.

B. Consideration of a Resolution Authorizing General Manager or Designee to Execute Interagency Cooperative Purchasing Agreements or Membership Agreements Which Comply With RCW Chapter 39.34

A motion unanimously passed approving Resolution No. 6255 authorizing General Manager or Designee to execute Interagency Cooperative Purchasing Agreements or Membership Agreements which comply with RCW Chapter 39.34.

C. Consideration of a Resolution Authorizing the CEO/General Manager or Designee to Purchase Supplies, Materials, and Equipment From or Through the United States Government in Accordance With RCW Chapter 39.32

A motion unanimously passed approving Resolution No. 6256 authorizing the CEO/General Manager or Designee to purchase supplies, materials, and equipment from or through the United States Government in accordance with RCW Chapter 39.32.

7. COMMISSION BUSINESS

A. Commission Reports

The Board reported on Commission related topics and Board related events.

B. Commissioner Event Calendar

Commissioner Olson asked about an upcoming joint chamber event on December 3, 2025. Deputy Clerk of the Board Jenny Rich stated she would send additional details.

There were no other changes to the Commissioner Event Calendar.

8. GOVERNANCE PLANNING

A. Governance Planning Calendar

There were no changes to the Governance Planning Calendar.

ADJOURNMENT

There being no further business or discussion to come before the Board, the Regular Meeting of November 18, 2025, adjourned at 10:34 a.m.

Approved this 2nd day of December, 2025.

Secretary

President

Vice President

BUSINESS OF THE COMMISSION

Meeting Date: December 2, 2025 **Agenda Item:** 3B

TITLE

CEO/General Manager's Report of Public Works Contract Award Recommendations; Formal Bid Award Recommendations; Professional Services Contract Award Recommendations; Miscellaneous Contract Award Recommendations; Cooperative Purchase Recommendations; Sole Source Purchase Recommendations; Emergency Declarations, Purchases and Public Works Contracts; Purchases Involving Special Facilities or Market Condition Recommendations; Formal Bid and Contract Amendments; and Contract Acceptance Recommendations

SUBMITTED FOR: Consent Agenda

Contracts/Purchasing	Clark Langstraat	5539
Department	*Contact*	*Extension*

Date of Previous Briefing:

Estimated Expenditure: Presentation Planned ☐

ACTION REQUIRED:

☐ Decision Preparation
- ☐ Policy Discussion
- ☐ Policy Decision
- ☒ Statutory

☐ Incidental (Information)

☐ Monitoring Report

SUMMARY STATEMENT:

Identify the relevant Board policies and impacts:

Governance Process, Board Job Description, GP-3(4) … non-delegable, statutorily assigned Board duty – Contracts and Purchasing.

The CEO/General Manager's Report of Public Works Contract Award Recommendations; Formal Bid Award Recommendations $120,000 and Over; Professional Services Contract Award Recommendations $200,000 and Over; Miscellaneous Contract Award Recommendations $200,000 and Over; Cooperative Purchase Recommendations; Sole Source Purchase Recommendations; Emergency Declarations, Purchases and Public Works Contracts; Purchases Involving Special Facilities or Market Condition Recommendations; Formal Bid and Contract Amendments; and Contract Acceptance Recommendations contains the following sections:

Public Works Contract Award Recommendations (Page 1);
Invitation to Bid No. 25-1604-KS with J.F. Brennan Company, Inc.

Formal Bid Award Recommendations $120,000 and Over (Page 2);
Request for Quotation No. 25-1608-CS with Carlson Sales Metering Solutions, LLC proposing GE Grid Solutions, LLC

Professional Services Contract Award Recommendations $200,000 and Over;
None

Miscellaneous Contract Award Recommendations $200,000 and Over (Page 3);
Miscellaneous No. 4500102119 with City of Seattle

Interlocal Agreements and Cooperative Purchase Recommendations;
Contracts:
None
Amendments:
None

Sole Source Purchase Recommendations;
None

Emergency Declarations, Purchases and Public Works Contracts;
None

Purchases Involving Special Facilities or Market Condition Recommendations;
None

Formal Bid and Contract Amendments (Pages 4 - 5);
Miscellaneous No. CW2247419 with DC Group

Contract Acceptance Recommendations;
None

List Attachments:
December 2, 2025 Report

Public Works Contract Award Recommendation(s)
December 2, 2025

ITB No. 25-1604-KS
Hat Island Submarine Cable Installation

No. of Bids Solicited:	52	
No. of Bids Received:	1	
Project Leader & Phone No.:	Eric Schneider	Ext. 8624
Estimate:	$8,500,000.00	

Staff has two separate recommendations related to this solicitation:

Recommendation 1: Reject the bids received as they were not responsive to the solicitation.
Recommendation 2: Authorize award of a contract to the J.F. Brennan Company, Inc. at their original bid price and substantially the same terms and conditions as were included in the bid package.

Description:
This contract consists of providing all labor, materials, and equipment necessary to replace a depreciated, 1974-installed submarine electrical cable that supplies power to Hat Island. The new District-supplied cable will be installed on the seafloor at a pre-determined location between the Port of Everett and Hat Island to ensure long-term reliability for island residents and will span approximately 32,400 feet. This over-water work is limited to certain months of the year. The cable landing sites on each end (Port of Everett and Hat Island) will utilize pre-installed infrastructure such as HDD conduits and vaults. Work will be coordinated with District crew for connection to existing distribution system. The work locations are 2920 Terminal Ave., Everett, WA 98201 and Hat Island Marina, in Snohomish County, Washington. Due to the specialty nature of the work, there are only three known marine contractors with the qualifications and equipment to perform the work.

Summary Statement Regarding Recommendation 1 non-responsive bids:	The bid submitted by J.F. Brennan Company, Inc. is considered non-responsive as Bid Item 9 exceeded the not-to-exceed cap amount by $233,000.00. A bid was submitted by Canpac Marine Services, Inc., but is considered non-responsive as: 1) it was not submitted using the required bid portal, Public Purchase; and 2) Bid Item 9 exceeded the not-to-exceed cap amount by $264,627.60. Michels Pacific Energy, Inc. submitted a "No Bid" response. For these reasons, staff recommend rejection of all bids.
Summary Statement Regarding Recommendation 2 to Award:	Having received no valid bids, RCW 54.04.080 authorizes the Commission to negotiate and award a contract for such work in lieu of readvertising. Staff recommends awarding a contract to J.F. Brennan at their original bid price and substantially the same terms and conditions as were included in the bid package. Rebidding this project could result in delays of as much as one year for this critical project due to permitting requirements from various governing agencies. Given the small bidding pool and the fact initial pricing has been made public there is no assurance the District would receive bids if the project were re-bid. J.F. Brennan's bid was less than the engineer's estimate and the firm is otherwise qualified to perform the work. As a result of these circumstances, staff determined that it is in the District's best interest to award to J.F. Brennan at their original bid price and substantially the same terms and conditions as were included in the bid package.

Formal Bid Award Recommendation(s) $120,000 And Over
December 2, 2025

RFQ No. 25-1608-CS
Five 115 kV Power Circuit Breakers

No. of Bids Solicited:	2	
No. of Bids Received:	1	
Project Leader & Phone No.:	Sanjeev Farwaha	x 5502
Material Estimate:	$1,500,000.00	

These 115 kV power circuit breakers will be installed at the Maltby Switching Station. They are used to isolate, switch, and protect the 115 kV transmission lines entering and exiting the switching station.

	Bidder	Subtotal (w/o tax)
Award To:	**Carlson Sales Metering Solutions, LLC proposing GE Grid Solutions, LLC**	**$844,000.00**

Summary Statement: Staff recommends awarding the contract to Carlson Sales Metering Solutions, LLC, proposing GE Grid Solutions, LLC, as the lowest evaluated responsible bidder to meet the District's specifications, in the amount of $844,000.00, plus applicable tariffs and taxes.

Miscellaneous Services Award Recommendation(s) $200,000 And Over
December 2, 2025

MISC. No. 4500102119
Operations & Maintenance
Charges for 2026

Project Leader & Phone No.:	Bob Anderson Ext. 4309
Estimate:	$900,000.00

In the late 1980's the Commission determined that the Darrington area should be served by a new substation connected to the Seattle City Light (SCL) transmission system. The North Mountain Substation was built and connected to Seattle's 230kV transmission system. While the District paid for the design and construction of the substation, the portion of the substation operating at 230kV, and the entire site was transferred to SCL ownership. In 1991, three agreements were negotiated covering the operations and maintenance responsibility, energy wheeling, and telecommunication channel capacity. These agreements require the District to cover the O&M expense of operating the 230kV portion of the substation, to pay for wheeling the energy over the SCL transmission system that is used in Darrington, and to pay a portion of the communication capacity that is used in the operation of the substation. The agreements have a 30-year term. The current Operations and Maintenance (O&M) Agreement became effective on November 1, 2022. A new contract is established each year to cover the funds paid to SCL.

	Vendor	Subtotal (w/o tax)
Award to:	**City of Seattle**	**$900,000.00**

Summary Statement: The $900,000.00 is an estimated amount for the entire year of 2026. It covers the O&M costs, telecommunications capacity, and energy wheeling charges that SCL assigns to the District for having the North Mountain Substation connected to their 230kV transmission system

MISC No. CW2247419
UPS Minor and Major Maintenance

Contractor/Consultant/Supplier:	DC Group	
Project Leader & Phone No.:	Kasey Westfall	Ext.1915
Amendment No.:	8	
Amendment:	$250,844.59	

Approximate Original Contract Amount:	$ 12,036.00		
Present Contract Amount:	$139,371.48	Original Start/End:	5/01/22 – 4/30/23
Amendment Amount:	$250,844.59	Present Start/End:	5/01/22 – 4/30/26
Approximate New Contract Amount:	$390,216.07	New End Date:	4/30/28

Summary Statement: This contract provides annual maintenance and service through a series of semi-annual and annual site visits that include system thermal scans, battery inspections, battery replacements, calibrations, power checks/adjustments, and software and firmware updates.

DC Group is one of two current vendors used by the District to maintain ten major critical Uninterruptible Power Supply (UPS) systems, including at the North County Modular Data Center. By consolidating with a single vendor, staff estimate savings of approximately 50%. DC Group has significant experience with District sites, systems and expectations.

Staff recommends approval of Amendment No. 8 to increase contract by a "Not to Exceed" amount of $250,844.59 and change the end date to 4/30/28.

Summary of Amendments:

Amendment No. 1 dated July 19, 2022, Increased contract amount by $17,441.76 for approved repairs.

Amendment No.2 dated April 26, 2023, Add funds of $12,036.00 and extend terms to 4/30/24 to exercise option to renew for year two

Amendment No. 3 dated May 4, 2023, Add funds of $6,400.00 to add new location with UPS and batteries.

Amendment No. 4 dated September 5, 2023, Add funds of $4,762.66 to replace and install failed Netcom 2 card on TC UPS. Failure caused remote operations of the UPS to not function.

Summary Statement (continued):

Amendment No. 5 dated March 15, 2024, Add funds of $68,259.06, extend terms to 4/30/25 to exercise option to renew and replace batteries that are required for the Telephone UPS, MDC UPS A and MDC UPS B.

Amendment No. 6 dated April 19, 2024, modifies Exhibit A Section 1.6 payment terms. "The DISTRICT shall pay the CONTRACTOR under the terms of the contract, based upon invoices submitted. Payment under this contract shall be made in advance annually as the work they are providing includes Emergency and Corrective Services."

Amendment No. 7 dated March 11, 2025, Add funds of $18,436.00 and extend terms to 4/30/26 to exercise option to renew.

BUSINESS OF THE COMMISSION

Meeting Date: December 2, 2025 **Agenda Item:** 3C

TITLE

Consideration of Certification/Ratification and Approval of District Checks and Vouchers

SUBMITTED FOR: Consent Agenda

General Accounting & Financial Systems	Shawn Hunstock	8497
Department	*Contact*	*Extension*

Date of Previous Briefing: _____

Estimated Expenditure: _____ Presentation Planned ☐

ACTION REQUIRED:

☐ Decision Preparation
- ☐ Policy Discussion
- ☐ Policy Decision
- ☒ Statutory

☐ Incidental (Information)

☐ Monitoring Report

SUMMARY STATEMENT:

Identify the relevant Board policies and impacts:

Governance Process, Board Job Description: GP-3(4)(B)(2)a non-delegable, statutorily assigned Board duty to approve vouchers for all warrants issued.

The attached District checks and vouchers are submitted for the Board's certification, ratification and approval.

List Attachments:
Voucher Listing

SNOHOMISH COUNTY PUD
PUBLIC UTILITY DISTRICT NO. 1

CERTIFICATION/RATIFICATION AND APPROVAL

We, the undersigned of the Public Utility District No. 1 of Snohomish County, Everett, Washington, do hereby certify that the merchandise or services hereinafter specified have been received, and the Checks or Warrants listed below are ratified/approved for payment this 2nd day of December 2025.

CERTIFICATION:

Certified as correct:

CEO/General Manager
Shawn Hunstock

Auditor
Jeff Bishop

Chief Financial Officer/Treasurer

RATIFIED AND APPROVED:

Board of Commissioners:

President

Vice-President

Secretary

TYPE OF DISBURSEMENT	PAYMENT REF NO.	DOLLAR AMOUNT	PAGE NO.
REVOLVING FUND			
Customer Refunds, Incentives and Other	1136916 - 1137545	$718,265.17	2 - 21
Electronic Customer Refunds		$4,761.52	22 - 23
WARRANT SUMMARY			
Warrants	8084511 - 8084656	$3,668,000.80	24 - 28
ACH	6059772 - 6060104	$5,300,476.74	29 - 39
Wires	7003809 - 7003819	$7,312,060.01	40
Payroll - Direct Deposit	5300001408 - 5300001408	$5,465,895.96	41
Payroll - Warrants	845596 - 845602	$19,275.98	41
Automatic Debit Payments	5300001405 - 5300001414	$3,514,579.04	42
	GRAND TOTAL	**$26,003,315.22**	

Revolving Fund - Customer Refunds, Incentives and Other			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/10/25	1136916	JEFF ELWOOD	$1,002.24
11/10/25	1136917	J & J PROPERTIES LLC	$205.47
11/10/25	1136918	WESTERN BLOSSOM HILL INVESTORS, LP	$11.49
11/10/25	1136919	MAHZAD MONTAZERI	$42.85
11/10/25	1136920	JOHN NEBEL	$108.30
11/10/25	1136921	SANDRA BERRY	$1,021.43
11/10/25	1136922	ROSIE NAMARA	$73.65
11/10/25	1136923	THOMAS CANGIALOSI	$113.74
11/10/25	1136924	BLAINE STEVENS	$87.63
11/10/25	1136925	CEP III - NIMBUS 25 LLC	$9.96
11/10/25	1136926	BETTY NEVAREZ	$1,346.00
11/10/25	1136927	CHUNG KWON	$12.59
11/12/25	1136928	KAREN PERALTA	$875.07
11/12/25	1136929	MAIISELA ZUNIGA GARCIA	$102.82
11/12/25	1136930	JOSEPHINE OLDS	$208.30
11/12/25	1136931	AUK-SILVERLAKE LLC	$7.59
11/12/25	1136932	ANTHONY LADAO	$88.39
11/12/25	1136933	MARCIA CRIOLLO GUTAMA	$212.00
11/12/25	1136934	SEBASTIAN HERNANDEZ MELENDEZ	$72.82
11/12/25	1136935	TERESA BACHELOR	$6,122.19
11/12/25	1136936	VOID	$0.00
11/12/25	1136937	SUHASINI JOSHI	$149.53
11/12/25	1136938	JOSEFA RAVEDURANGO	$110.81
11/12/25	1136939	DI WANG	$21.64
11/12/25	1136940	EVE ELWOOD	$135.48
11/12/25	1136941	GRETSY DAVILA SANTIAGO	$133.99
11/12/25	1136942	NORTHFIELD PROPERTIES	$802.25
11/12/25	1136943	II DONALD ROPER	$7.88
11/12/25	1136944	CARLOS SERRANO	$120.84
11/12/25	1136945	LINK LOGISTICS REAL ESTATE MGMT LLC	$8,309.40
11/12/25	1136946	GLEIBERMAN PROPERTIES INC	$6.16
11/12/25	1136947	SR THOMAS LITTLE	$152.92

Revolving Fund - Customer Refunds, Incentives and Other			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/12/25	1136948	RAUL ALEJANDRO ZERPA DORTA	$40.84
11/12/25	1136949	LINDA ZAMANI	$79.64
11/12/25	1136950	FRANKLIN LORENZO	$135.78
11/12/25	1136951	VOID	$0.00
11/12/25	1136952	SNO TOWN DEVELOPERS LLC	$219.03
11/12/25	1136953	MONROE BUEHRING	$60.24
11/12/25	1136954	SHARON HALE	$38.00
11/12/25	1136955	DUSTIN KLIFMAN	$63.00
11/13/25	1136956	ISAAC MARLEAU	$718.19
11/13/25	1136957	BECKY ABRAMS	$147.66
11/13/25	1136958	MEEJA SHIN	$210.34
11/13/25	1136959	CODY TOUCHETTE	$282.34
11/13/25	1136960	2003-WLD BRUNTSFIELD LLC	$66.48
11/13/25	1136961	LEXUS CALL	$85.50
11/13/25	1136962	NIKOLAY LYSOV	$22.88
11/13/25	1136963	PACIFIC RIDGE - DRH, LLC	$74.21
11/13/25	1136964	ALTERNATIVE SUITES INT LLC	$11.90
11/13/25	1136965	ELVIRA PERLA BADANAC	$810.56
11/13/25	1136966	MAURA CASTILLO	$7.13
11/13/25	1136967	WILLIAMS INVESTMENTS	$41.16
11/13/25	1136968	JANET BUEHLER	$61.02
11/13/25	1136969	MLT STATION II LLC	$19.59
11/13/25	1136970	MLT STATION II LLC	$5.51
11/13/25	1136971	CRAIG NOVEL	$91.67
11/13/25	1136972	DEMIZKA MAG	$954.03
11/13/25	1136973	MARIA YARANON	$18.27
11/13/25	1136974	JESUS LOPEZ	$363.95
11/13/25	1136975	DONNA LAING	$106.87
11/13/25	1136976	SHAWN FAIN	$986.58
11/13/25	1136977	GLY CONSTRUCTION	$4,996.35
11/13/25	1136978	MARIANNA BURTON	$21.33
11/13/25	1136979	HAI NGUYEN	$113.41

Revolving Fund - Customer Refunds, Incentives and Other			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/13/25	1136980	VICKIE MANTOOTH	$195.00
11/13/25	1136981	MARYSVILLE 136TH ST LLC	$4,019.07
11/14/25	1136982	ANNA MARIZ	$43.12
11/14/25	1136983	JOHN SAVAGE	$24.51
11/14/25	1136984	KIM VRANICH	$31.55
11/14/25	1136985	PAMELA VINES	$66.65
11/14/25	1136986	ESAYAS GEZEHEGN	$110.00
11/14/25	1136987	NARGES ZARIBAF	$78.72
11/14/25	1136988	KELLY WING	$225.49
11/14/25	1136989	WASHINGTON GRANITE LLC	$412.42
11/14/25	1136990	THOMAS LIANG	$12.69
11/14/25	1136991	RESHAL PLOEGER	$58.78
11/14/25	1136992	JAYMI GRAHAM	$40.17
11/14/25	1136993	BYUNG YOON	$66.60
11/14/25	1136994	LUCIA CAMPAGNA	$137.64
11/14/25	1136995	VOID	$0.00
11/14/25	1136996	ANN FAIRES	$31.22
11/14/25	1136997	CHARLENE RICE	$46.32
11/14/25	1136998	SHAUN HARRIS	$48.75
11/17/25	1136999	WESTERN BLOSSOM HILL INVESTORS, LP	$6.26
11/17/25	1137000	TEMPLE BETH OR	$31.33
11/17/25	1137001	DEVANG TANEJA	$361.41
11/17/25	1137002	LAURA SOLVANG	$5,062.39
11/17/25	1137003	SCOTT DELAP	$862.44
11/17/25	1137004	CHALANDA PLEASANT	$200.00
11/17/25	1137005	ROD ADDICOTT	$68.27
11/17/25	1137006	GABRIEL QUESADA	$1,652.85
11/17/25	1137007	MARIA FLORES	$73.69
11/17/25	1137008	DONALD STANYER	$18.39
11/17/25	1137009	STU SCHELL	$387.92
11/17/25	1137010	SOR INVESTMENTS LLC	$27.74
11/17/25	1137011	20225 BOTHELL, LLC	$62.24

Revolving Fund - Customer Refunds, Incentives and Other			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/17/25	1137012	LACEY FAYARD	$464.62
11/18/25	1137013	SHANA SWANSON	$1,253.52
11/18/25	1137014	PATRICIA RAMEY	$892.62
11/18/25	1137015	TANYA MARKHAM	$1,316.91
11/18/25	1137016	BRIDGET WISNIEWSKI	$1,074.78
11/18/25	1137017	EDDIE OLSON	$823.68
11/18/25	1137018	RON PENELERICK	$1,648.65
11/18/25	1137019	DIANNE HACKNEY	$934.92
11/18/25	1137020	JEANINE SANCLEMENTE	$976.29
11/18/25	1137021	DOUG MAXFIELD	$1,927.44
11/18/25	1137022	JEFFREY LEHMAN	$1,760.01
11/18/25	1137023	ALISON SUTTLES	$490.60
11/18/25	1137024	SUZANNE OVERSVEE	$439.66
11/18/25	1137025	RAMAN AGARWAL	$858.06
11/18/25	1137026	SUPERIOR GLAZING SOLUTIONS LLP	$1,097.64
11/18/25	1137027	LAURENCE MICKELSON	$888.80
11/18/25	1137028	HUI ZHANG	$866.88
11/18/25	1137029	CHANDRA PRAKASH GARG	$1,326.50
11/18/25	1137030	VIPUL AGGARWAL	$582.96
11/18/25	1137031	CHRISTINA JOHNS	$1,680.84
11/18/25	1137032	JESSICA LEE	$1,891.08
11/18/25	1137033	ARTHUR BUONAMIA	$1,974.70
11/18/25	1137034	MARK EARLY	$1,253.76
11/18/25	1137035	AKSHAY SHAH	$1,180.34
11/18/25	1137036	JOHN CARL MARSHALL	$374.64
11/18/25	1137037	ROBERT GOTTWALD	$1,845.00
11/18/25	1137038	ROBERT MILLER	$1,503.04
11/18/25	1137039	CHRISTINE MUONGCHANH	$582.40
11/18/25	1137040	KAREN FORESTER	$1,316.88
11/18/25	1137041	RUSS TILTON	$1,104.81
11/18/25	1137042	NANCY ANDERSON	$642.24
11/18/25	1137043	MATTHEW PALUCH	$1,610.46

Revolving Fund - Customer Refunds, Incentives and Other			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/18/25	1137044	DONALD FLEMING	$1,555.26
11/18/25	1137045	MD JEFFREY HART	$1,898.56
11/18/25	1137046	NOLA BOEHM	$673.60
11/18/25	1137047	ADAM CLARK	$1,788.99
11/18/25	1137048	MICHAEL LEVINE	$2,389.38
11/18/25	1137049	CHRISTOPHER CONNAIR	$1,124.28
11/18/25	1137050	MICHAEL LOGES	$1,281.21
11/18/25	1137051	RODNEY COOK	$1,164.88
11/18/25	1137052	DAVID HUMMER	$1,580.25
11/18/25	1137053	MARVIN LONG	$1,887.69
11/18/25	1137054	JOY MCBRIDE	$1,034.64
11/18/25	1137055	MEGAN IIAMS-HAUSER	$1,203.84
11/18/25	1137056	GEOFF KENWAY	$614.32
11/18/25	1137057	MARY PEPHYRS	$528.16
11/18/25	1137058	RYAN RODINE	$823.14
11/18/25	1137059	JAMIE EASTERLY	$858.78
11/18/25	1137060	THOMAS ISENHART	$1,803.42
11/18/25	1137061	JAMES SCHRADER	$2,024.28
11/18/25	1137062	NICK BEAUMONT	$1,348.80
11/18/25	1137063	DAVID MILLER	$2,135.88
11/18/25	1137064	WRAY LARSON	$1,033.41
11/18/25	1137065	NARENDRA SINGH	$1,570.80
11/18/25	1137066	DEBRA CAMPBELL	$1,458.56
11/18/25	1137067	JERADIAH BAUER	$1,131.48
11/18/25	1137068	PHILIP SKOOG	$964.62
11/18/25	1137069	CLAY THOMPSON	$1,146.18
11/18/25	1137070	ALAN HYATT	$1,105.86
11/18/25	1137071	ADAM FARNHAM	$1,886.94
11/18/25	1137072	MARYSVILLE SCHOOL DIST 25	$1,552.64
11/18/25	1137073	HEATHER NORDELL	$1,732.23
11/18/25	1137074	SANDRA BENNETT	$821.16
11/18/25	1137075	LARA POHL	$1,731.66

Revolving Fund - Customer Refunds, Incentives and Other			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/18/25	1137076	GLORIA BUNKER	$2,196.36
11/18/25	1137077	DAVID NIGENDA	$1,545.18
11/18/25	1137078	MICAH WESSMAN	$1,177.02
11/18/25	1137079	JIM KUTZ	$1,728.36
11/18/25	1137080	DAWNA SANCHEZ	$105.63
11/18/25	1137081	BHARGHAV SABBINENI	$903.47
11/18/25	1137082	NANCY WILLIAMS	$1,799.98
11/18/25	1137083	OHANA DREAMS LLC	$389.99
11/18/25	1137084	JACOB MARTIN	$180.81
11/18/25	1137085	MILAN STEFANOVIC	$712.98
11/18/25	1137086	DANIEL CHRISTOFFERSON	$1,760.94
11/18/25	1137087	DIAN WADE	$130.46
11/18/25	1137088	BILL SCHOENBACHLER	$1,012.80
11/18/25	1137089	MICHEL TENNY SMITH	$986.79
11/18/25	1137090	MICHAEL LEWIS	$716.94
11/18/25	1137091	PAT DARRAH	$956.70
11/18/25	1137092	LAUREL BALLOU	$555.38
11/18/25	1137093	MELODIE GARRISON	$1,436.08
11/18/25	1137094	DONALD PATE	$1,669.32
11/18/25	1137095	ERIKA CERVANTES	$760.80
11/18/25	1137096	TODD PULLMAN	$1,082.34
11/18/25	1137097	MEGAN BARON	$978.60
11/18/25	1137098	COLIN KREIGER	$1,232.10
11/18/25	1137099	JAMES DAY	$1,560.80
11/18/25	1137100	JESSICA TRIMBLE	$974.12
11/18/25	1137101	BEN DUBOSE	$148.76
11/18/25	1137102	BRYCE RIDDELL	$2,129.19
11/18/25	1137103	D KNOBBS	$1,082.52
11/18/25	1137104	JASON BECKER	$2,097.48
11/18/25	1137105	RICHARD BENEFIEL	$1,560.30
11/18/25	1137106	THOMAS SACCO	$2,063.34
11/18/25	1137107	ANTHONY PEHANICH	$1,759.59

Revolving Fund - Customer Refunds, Incentives and Other			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/18/25	1137108	LOREN VAN LOO	$1,601.04
11/18/25	1137109	MARGARET FYNN	$2,006.10
11/18/25	1137110	MARIA COTE	$2,130.12
11/18/25	1137111	SARAH BECK	$1,265.35
11/18/25	1137112	DAVID LANDON	$1,228.50
11/18/25	1137113	AMY SELLS HAIST	$1,804.68
11/18/25	1137114	JACQUELINE WOOD	$1,340.64
11/18/25	1137115	CATHY FLIRIS	$956.00
11/18/25	1137116	SUSAN AZNOFF	$747.26
11/18/25	1137117	ZOPHIE LESLEA	$722.82
11/18/25	1137118	TODD BROWN	$1,183.35
11/18/25	1137119	ELIZABETH PANTLEY	$579.04
11/18/25	1137120	RYAN SNODGRASS	$458.36
11/18/25	1137121	MARY SCHROEDER	$1,116.18
11/18/25	1137122	GARTH STEIN	$1,989.90
11/18/25	1137123	ASTRID BEAR	$439.18
11/18/25	1137124	NAGESWARA-RAO MERLA	$1,242.99
11/18/25	1137125	GERRY SALVADALENA	$696.35
11/18/25	1137126	STEVE WARNER	$966.87
11/18/25	1137127	ANNEMARIE GAUDIN	$946.32
11/18/25	1137128	MARK INGHAM	$1,126.80
11/18/25	1137129	WILLIAM KINTNER	$2,283.84
11/18/25	1137130	PAUL VIJGEN	$1,023.47
11/18/25	1137131	JOHN RUBERO	$823.41
11/18/25	1137132	WENDELL JOHNSON	$1,368.32
11/18/25	1137133	BENJAMIN MCMAIL	$522.72
11/18/25	1137134	MARY MEAD	$995.04
11/18/25	1137135	KERRY KNIGHT	$1,849.47
11/18/25	1137136	MARK BROCIOUS	$2,455.11
11/18/25	1137137	BRIAN GRANT	$2,341.71
11/18/25	1137138	ABHISHEK SINGH BAGHEL	$1,030.68
11/18/25	1137139	ADRIAN ALDINGER	$1,595.52

Revolving Fund - Customer Refunds, Incentives and Other			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/18/25	1137140	LISA COLE	$1,686.09
11/18/25	1137141	NOEL FORREST	$603.12
11/18/25	1137142	KURTIS STORY	$1,492.05
11/18/25	1137143	TODD HA	$321.12
11/18/25	1137144	RONALD UHLMAN	$841.28
11/18/25	1137145	KARAMCHAND MUPPIDI	$938.28
11/18/25	1137146	DAVID BOYER	$1,872.08
11/18/25	1137147	ERIK NOYD	$1,492.68
11/18/25	1137148	ROBERT LOWE	$1,383.30
11/18/25	1137149	SEJIN KIM	$652.68
11/18/25	1137150	ASHLEY MAI	$1,641.36
11/18/25	1137151	JOSEPH NAWROCKI	$828.72
11/18/25	1137152	RHONDA GENDRON	$331.52
11/18/25	1137153	DENNIS GOULD	$1,052.31
11/18/25	1137154	STEPHANIE BATES	$498.80
11/18/25	1137155	DAN HINES	$1,986.48
11/18/25	1137156	KRISTEN BENDIXSEN	$1,203.30
11/18/25	1137157	DONALD GEORGE	$1,791.72
11/18/25	1137158	CHRISTOPHER OXFORD	$451.26
11/18/25	1137159	JAHTI MANSELLE	$1,648.29
11/18/25	1137160	MAQBOOL MALIK	$1,889.76
11/18/25	1137161	EDWARD MADURA	$1,773.72
11/18/25	1137162	ANTHONY NGUYEN	$1,953.63
11/18/25	1137163	GULSHAN KHARBANDA	$1,380.33
11/18/25	1137164	SARAH MITCHELL	$1,513.98
11/18/25	1137165	PUGET PARK LLC	$1,352.01
11/18/25	1137166	PEGGY HUGHES	$997.20
11/18/25	1137167	CHUCK SCHUFREIDER	$1,399.68
11/18/25	1137168	PAULA COWDREY	$521.69
11/18/25	1137169	JOSUE CRUZ LOPEZ	$1,639.44
11/18/25	1137170	ERIC JOHNSON	$606.69
11/18/25	1137171	VERAX CHEMICAL CO	$4,586.12

Revolving Fund - Customer Refunds, Incentives and Other			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/18/25	1137172	RUTH SILUE	$814.86
11/18/25	1137173	DONNA ROBERTS	$1,330.28
11/18/25	1137174	ANDY SORGEN	$1,068.48
11/18/25	1137175	LEONA BENSON	$972.72
11/18/25	1137176	MICHAEL BALL	$338.40
11/18/25	1137177	RUSSELL OLIVER	$1,167.04
11/18/25	1137178	LOUIS SAEKOW	$3,688.32
11/18/25	1137179	TRACI FONTYN	$2,429.89
11/18/25	1137180	MAUREEN GRAHAM	$702.72
11/18/25	1137181	ALYSSA STICKNEY	$1,820.49
11/18/25	1137182	JADE NG	$1,914.15
11/18/25	1137183	JR CHARLES PITTMAN	$1,449.63
11/18/25	1137184	DAVID BEARDSLEY	$1,811.52
11/18/25	1137185	ALVARO GARAY	$1,778.04
11/18/25	1137186	NICHOLAS MILLER	$726.60
11/18/25	1137187	ANNE BUSH	$552.60
11/18/25	1137188	GLENDA KRULL	$462.06
11/18/25	1137189	RICHARD SUDBURY	$838.95
11/18/25	1137190	SUSAN OSBORN	$2,016.72
11/18/25	1137191	LILIA RAKHMET-ZADE	$1,382.58
11/18/25	1137192	PUNNIYA DHARSHAN GANESAN	$1,546.20
11/18/25	1137193	SANOOP THRIVIKRAMAN NAMPOOTHIRI	$1,091.79
11/18/25	1137194	DEVIN TAYLOR	$403.02
11/18/25	1137195	MARY SHANK	$1,603.56
11/18/25	1137196	THEODORE BROWN	$1,440.36
11/18/25	1137197	MICHAEL MC EACHERN	$214.74
11/18/25	1137198	KELLY ENGELBRACHT	$2,246.94
11/18/25	1137199	WILLIAM MCCLAIN	$880.88
11/18/25	1137200	JOHN FIRST	$1,029.78
11/18/25	1137201	BARBARA BOMARC	$577.80
11/18/25	1137202	NICHOLAS KELLY	$1,382.76
11/18/25	1137203	ERIK MEYER	$1,437.80

Revolving Fund - Customer Refunds, Incentives and Other			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/18/25	1137204	JONATHAN LOHRMANN	$1,707.16
11/18/25	1137205	MARK BEALES	$1,630.98
11/18/25	1137206	CHRISTINE NAULT	$1,406.70
11/18/25	1137207	CHRYSTIE SCHMELTER	$1,504.32
11/18/25	1137208	REGINA MOORE	$2,029.86
11/18/25	1137209	BRIANNE HUGHES	$1,070.37
11/18/25	1137210	JEREMY WILMS	$680.40
11/18/25	1137211	RASA RAISYS	$1,255.66
11/18/25	1137212	BERYL KNAUTH	$1,041.39
11/18/25	1137213	JESSICA BERG	$1,727.82
11/18/25	1137214	YVETTE GOODWIN	$703.44
11/18/25	1137215	ERIC ALLAN	$1,303.02
11/18/25	1137216	JANETTE RONQUILLO	$804.18
11/18/25	1137217	MATTHEW STOUDT	$2,240.70
11/18/25	1137218	ROBYN MORTENSEN	$1,415.88
11/18/25	1137219	HEATHER PARRISH	$1,267.98
11/18/25	1137220	JASON PIERCE	$2,429.07
11/18/25	1137221	JESSICA GILLESPIE	$1,352.00
11/18/25	1137222	JENNIFER MURRWEISS	$1,277.28
11/18/25	1137223	RUTH BRANDAL	$813.42
11/18/25	1137224	JR FRED BARTEL	$1,513.47
11/18/25	1137225	LAURA SOLVANG	$1,872.84
11/18/25	1137226	ERIN SUTCLIFFE	$1,851.08
11/18/25	1137227	ROBERT DAVIS	$2,120.79
11/18/25	1137228	CRAIG ARNO	$1,307.04
11/18/25	1137229	ASHLEY GARIBALDI	$1,791.36
11/18/25	1137230	GARY PARKER	$791.46
11/18/25	1137231	RACHELL HELLE	$2,083.50
11/18/25	1137232	ROCHELLE LUBBERS	$1,210.50
11/18/25	1137233	CATALINA ANGEL	$2,024.61
11/18/25	1137234	LEE FREEMAN	$2,389.38
11/18/25	1137235	NEGEEN SMEDLEY	$1,418.40

Revolving Fund - Customer Refunds, Incentives and Other			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/18/25	1137236	ARTUR KEDZIERSKI	$345.19
11/18/25	1137237	LISA PACE	$830.40
11/18/25	1137238	TAYLOR GOODHART	$1,314.18
11/18/25	1137239	ANTON KOVEZA	$1,119.06
11/18/25	1137240	HOPEWORKS SOCIAL ENTERPRISES	$11,768.72
11/18/25	1137241	RAYNE WATTERS	$1,123.92
11/18/25	1137242	CAROL SCHRECK	$1,058.04
11/18/25	1137243	DEBRA NORTHEY	$987.00
11/18/25	1137244	JAMES BALCH	$1,657.80
11/18/25	1137245	YVONNE CONNELLY	$1,420.02
11/18/25	1137246	PAT MURPHY	$1,752.48
11/18/25	1137247	LINCOLN HILL RETIREMENT COMMUNITY	$9,177.08
11/18/25	1137248	KERRY HORNER	$1,790.88
11/18/25	1137249	TIFFANY BIDNE	$945.54
11/18/25	1137250	DOUG HERTZOG	$1,438.74
11/18/25	1137251	TOM HEINZ	$1,678.11
11/18/25	1137252	JACOB THOMAS	$1,854.30
11/18/25	1137253	KIP CARVER	$1,064.98
11/18/25	1137254	GEORGE VASIL	$1,610.46
11/18/25	1137255	PEGGY CANELL	$1,200.98
11/18/25	1137256	REBECCA JETTE	$1,451.34
11/18/25	1137257	DAVID SUNDQUIST	$1,520.40
11/18/25	1137258	JUDY YORK	$812.49
11/18/25	1137259	ASHLEY GANSER	$2,341.06
11/18/25	1137260	KIM DANG	$855.33
11/18/25	1137261	DAVID SWANEY	$871.50
11/18/25	1137262	KEVIN HASKINS	$1,524.32
11/18/25	1137263	JOSEPH KING	$60.78
11/18/25	1137264	JOEL MILLER	$1,025.32
11/18/25	1137265	BRYAN MIZE	$723.06
11/18/25	1137266	MARK ALLEN	$1,847.70
11/18/25	1137267	CHARLEEN SPAETH	$1,864.38

Revolving Fund - Customer Refunds, Incentives and Other			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/18/25	1137268	GAMBA HARRIS	$400.00
11/18/25	1137269	CANDICE SMITH	$1,534.86
11/18/25	1137270	DEBRA BASSETT	$1,546.44
11/18/25	1137271	KAREN ERNST	$1,061.34
11/18/25	1137272	KEITH HADFIELD	$1,004.22
11/18/25	1137273	SANDRA CENTALA	$1,431.36
11/18/25	1137274	THAO NGUYEN	$1,904.07
11/18/25	1137275	MARK KREUTZ	$2,300.97
11/18/25	1137276	DOUGLAS FREYBERG	$2,454.21
11/18/25	1137277	JACK JESSUP	$1,758.24
11/18/25	1137278	SAUL CACERES	$898.02
11/18/25	1137279	GAIL BLACKSTONE	$2,488.08
11/18/25	1137280	ANDREW STEVERMER	$1,368.00
11/18/25	1137281	IAN ENDER	$808.50
11/18/25	1137282	PAIGE LEWIS	$2,411.43
11/18/25	1137283	EMILY WICKS	$1,700.46
11/18/25	1137284	TERRY LIPPINCOTT	$994.56
11/18/25	1137285	SYLVIA KESSLER	$854.70
11/18/25	1137286	TIMOTHY TREPTOW	$1,445.43
11/18/25	1137287	DARLENE CASTLE	$562.86
11/18/25	1137288	JOHN PROBSTFIELD	$1,755.46
11/18/25	1137289	TOM CRISP	$1,627.38
11/18/25	1137290	PEGGY MILLER	$1,095.48
11/18/25	1137291	WESLEY FRAZIER	$840.18
11/18/25	1137292	DANIEL LOKIC	$1,059.45
11/18/25	1137293	MANJUNATH VAGADURGI	$1,627.20
11/18/25	1137294	COURTNEY JACOBSON	$855.18
11/18/25	1137295	SVREAL LLC	$3,922.62
11/18/25	1137296	FRANCESCO ROGANO	$1,968.96
11/18/25	1137297	CATHERINE SANETRA	$712.98
11/18/25	1137298	CRAIG HAUGSTAD	$1,180.62
11/18/25	1137299	JASON HOLLAND	$2,052.90

Revolving Fund - Customer Refunds, Incentives and Other			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/18/25	1137300	KEVIN SUMMERS	$2,058.66
11/18/25	1137301	REED GRAPENSTETER	$1,775.16
11/18/25	1137302	PATRICIA SMITH	$137.52
11/18/25	1137303	MELANIE PETERSON	$384.30
11/18/25	1137304	CHERI PRUDNICK	$1,630.44
11/18/25	1137305	LINDA PARKER	$910.26
11/18/25	1137306	JEREMY PUSAKULICH	$1,684.44
11/18/25	1137307	HEIDI CONAHAN	$1,871.10
11/18/25	1137308	PETER CHRISTENSEN	$2,022.66
11/18/25	1137309	CHERYL MERCER	$2,100.42
11/18/25	1137310	JOHN TWOHY	$1,855.04
11/18/25	1137311	GAURAV SHARMA	$1,191.68
11/18/25	1137312	YVETTE SANCHEZ	$1,274.49
11/18/25	1137313	JAMES KASSEBAUM	$2,456.37
11/18/25	1137314	RICK JURKOVIC	$1,940.61
11/18/25	1137315	DWAYNE HOUSE	$1,609.86
11/18/25	1137316	THOMAS HARPER	$1,119.30
11/18/25	1137317	RALEIGH STEIN	$826.92
11/18/25	1137318	GARRON HAUN	$715.05
11/18/25	1137319	MARK MAGEE	$559.36
11/18/25	1137320	DANICA EDGINGTON	$1,746.90
11/18/25	1137321	SHRADDHA BHARGAVA	$752.71
11/18/25	1137322	ANNA HAALA	$1,564.56
11/18/25	1137323	RICHARD WILSON	$1,118.88
11/18/25	1137324	CALEB SIERER	$1,177.38
11/18/25	1137325	EILEEN BOWEN	$1,112.80
11/18/25	1137326	MATTHEW ZELLER	$1,894.62
11/18/25	1137327	WENDY JOHNSON	$1,980.18
11/18/25	1137328	HARRY LUNDSTROM	$1,310.94
11/18/25	1137329	HEATH CALKINS	$1,417.44
11/18/25	1137330	GARY ANDERTON	$29.12
11/18/25	1137331	MIKE OWEN	$1,274.07

Revolving Fund - Customer Refunds, Incentives and Other			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/18/25	1137332	LINDA UPCHURCH	$1,168.86
11/18/25	1137333	RANDY PRUDEN	$1,285.62
11/18/25	1137334	DON CHO	$1,223.74
11/18/25	1137335	JESSICA ELLERSICK	$1,033.83
11/18/25	1137336	TERESA FOWLER	$2,079.21
11/18/25	1137337	ROBERT REICHLE	$2,364.81
11/18/25	1137338	L DEAN POPPE	$945.00
11/18/25	1137339	VLADIMIR BORISOV	$1,547.28
11/18/25	1137340	DAN STROHL	$1,393.28
11/18/25	1137341	MICHAEL HALL	$898.56
11/18/25	1137342	MAKSIM SERGIYENKO	$937.44
11/18/25	1137343	SANDRA RECHEUNGEL	$786.24
11/18/25	1137344	TODD M GRAY	$1,467.00
11/18/25	1137345	STEPHANIE KOLB	$800.31
11/18/25	1137346	MICHAEL POLLI	$1,223.88
11/18/25	1137347	DONALD FAULKNER	$1,670.76
11/18/25	1137348	ALTES HAUS LLC	$925.20
11/18/25	1137349	MICHAEL PRIHODA	$1,721.79
11/18/25	1137350	LOUISE SILVA	$928.00
11/18/25	1137351	RANDALL KING	$1,528.02
11/18/25	1137352	BRANDON KING	$2,055.60
11/18/25	1137353	MARY BEATTIE	$2,325.24
11/18/25	1137354	MATTHEW NGUYEN	$2,008.44
11/18/25	1137355	WENDY FORD	$1,249.29
11/18/25	1137356	KATIE LAMA	$649.74
11/18/25	1137357	III JOHN CRAMER	$1,981.62
11/18/25	1137358	CRAIG GRUEL	$1,887.48
11/18/25	1137359	LESLIE PARRISH	$1,035.02
11/18/25	1137360	KELLY WETSCH	$979.56
11/18/25	1137361	CARL THOMPSON	$1,978.62
11/18/25	1137362	ROD MCGILLIVRAY	$164.12
11/18/25	1137363	LAURI HARPER	$1,023.48

Revolving Fund - Customer Refunds, Incentives and Other			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/18/25	1137364	KEITH PAPKA	$1,530.27
11/18/25	1137365	LYDIA DOUGLAS	$865.26
11/18/25	1137366	MARK CHRISTENSEN	$1,715.40
11/18/25	1137367	BRAD ROCHON	$2,375.28
11/18/25	1137368	LORA HEIN	$659.61
11/18/25	1137369	RICHARD DEAN	$1,208.34
11/18/25	1137370	NICHOLAS PEDDY	$376.88
11/18/25	1137371	DOUGLAS ROBECK	$453.60
11/18/25	1137372	ISABEL BULL	$1,296.36
11/18/25	1137373	NAM NGUYEN	$2,259.54
11/18/25	1137374	SAMANTHA LEE	$1,831.84
11/18/25	1137375	SATYA PULUGURTA	$1,754.90
11/18/25	1137376	JOSEPH SANDERS	$1,517.04
11/18/25	1137377	LINDA MEYER	$1,310.26
11/18/25	1137378	DEVEN OSTMAN	$1,132.95
11/18/25	1137379	WENDY KAY	$960.33
11/18/25	1137380	YOGITA GARUD	$472.92
11/18/25	1137381	LEIGH BUCHAN HARVEY	$1,008.21
11/18/25	1137382	DWIGHT BICKEL	$1,598.40
11/18/25	1137383	FRANCES FORSYTHE	$1,426.53
11/18/25	1137384	CHAPIN SMITH	$1,892.94
11/18/25	1137385	MARTIN KORTEKAAS	$1,983.96
11/18/25	1137386	GREG KANEHEN	$1,129.50
11/18/25	1137387	RANDOLPH BRASFIELD	$2,071.62
11/18/25	1137388	LYNDA REYNOLDS	$1,895.04
11/18/25	1137389	ALICE TILTON	$10.20
11/18/25	1137390	DEREK HUNTER	$867.24
11/18/25	1137391	BRETT GRIFFIN	$1,899.00
11/18/25	1137392	CHRIS NASTOS	$1,135.40
11/18/25	1137393	TREVOR FOX	$1,933.38
11/18/25	1137394	MARIA GARGARI	$1,689.12
11/18/25	1137395	NAMITA AGRAWAL	$1,122.30

Revolving Fund - Customer Refunds, Incentives and Other			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/18/25	1137396	SHELLY BERRY	$1,555.84
11/18/25	1137397	BRAMBLEMIRE INC	$1,683.36
11/18/25	1137398	JOHN DIVELY	$714.14
11/18/25	1137399	SUSAN SWAFFORD	$1,721.70
11/18/25	1137400	MAREK JEDRZEJEWICZ	$608.72
11/18/25	1137401	SHWETA RAJE	$1,762.38
11/18/25	1137402	JAMES WATKINS	$2,049.18
11/18/25	1137403	KIMBERLEE DANIELSON	$2,086.02
11/18/25	1137404	STEVEN COTTERILL	$2,138.85
11/18/25	1137405	EDWARD ECKERMAN	$1,847.58
11/18/25	1137406	JEFFERY SCHEMPP	$783.09
11/18/25	1137407	ERICK OLSON	$1,649.70
11/18/25	1137408	MATTHEW RIGGEN	$1,524.18
11/18/25	1137409	SHARRIEE LADSON	$871.56
11/18/25	1137410	JUDY BUSSING	$1,253.88
11/18/25	1137411	STEVE HIMEL	$1,437.12
11/18/25	1137412	MATT KAHLER	$459.90
11/18/25	1137413	SEUNG YOO	$1,454.04
11/18/25	1137414	SCOTT YANAGIDA	$1,487.52
11/18/25	1137415	JOSHUA ARMSTRONG	$1,339.38
11/18/25	1137416	JULIA ALLEN	$2,065.14
11/18/25	1137417	JOE BIWER	$942.66
11/18/25	1137418	BEN WEIGEL	$1,710.72
11/18/25	1137419	MARGARET KASE	$1,124.13
11/18/25	1137420	JODY ELSOM	$303.66
11/18/25	1137421	JOHN BOONE	$1,018.44
11/18/25	1137422	LARRY CRONIN	$1,747.83
11/18/25	1137423	PETER MILLIKAN	$871.50
11/18/25	1137424	JOSEPH CATALINI	$188.16
11/18/25	1137425	ROCKY LANCASTER	$2,456.58
11/18/25	1137426	PATRICIA DAVIS	$916.92
11/18/25	1137427	MARK EKMAN	$1,900.92

Revolving Fund - Customer Refunds, Incentives and Other			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/18/25	1137428	SLAVIK YAKOBCHUK	$1,748.46
11/18/25	1137429	LAURI MACE	$878.94
11/18/25	1137430	STELLA KEHOE	$1,737.00
11/18/25	1137431	BENJAMIN MCLAUGHLIN	$1,047.78
11/18/25	1137432	JENNIFER ROSS	$964.48
11/18/25	1137433	CINDY ANSELMI	$1,686.72
11/18/25	1137434	DAVID PARKS	$1,098.02
11/18/25	1137435	KATHERINE VANBRUSKIRK	$1,212.54
11/18/25	1137436	TODD SCHRAM	$2,081.52
11/18/25	1137437	SURENDRAN SUBRAMANIAN	$754.74
11/18/25	1137438	ERIN ARGUELLES	$2,301.66
11/18/25	1137439	JOHN RANDLE	$668.70
11/18/25	1137440	EWEN MACAULAY	$1,739.16
11/18/25	1137441	JONATHAN HALL	$1,362.78
11/18/25	1137442	JOE ZAVAGLIA	$880.20
11/18/25	1137443	BAY RAITT	$585.36
11/18/25	1137444	TEJAN KHARANGATE	$1,933.02
11/18/25	1137445	LAURA BALLARD	$1,946.88
11/18/25	1137446	VICKI FOX	$1,597.68
11/18/25	1137447	JACK NUHSE	$2,078.45
11/18/25	1137448	SUZANNE LYNN	$2,177.28
11/18/25	1137449	RICHARD MCGUIRE	$766.71
11/18/25	1137450	SUSAN MCMANAMEN	$1,041.92
11/18/25	1137451	HARRY CUSTER	$1,099.98
11/18/25	1137452	PATRICK HAUGSTAD	$1,054.26
11/18/25	1137453	LEIGH ANN RUIJTERS	$1,345.28
11/18/25	1137454	CHRISTY HARRIS	$1,034.46
11/18/25	1137455	NICHOLAS THOMPSON	$1,836.72
11/18/25	1137456	CHRIS O'CONNOR	$1,585.44
11/18/25	1137457	JAMIE MALLAHAN	$1,748.16
11/18/25	1137458	GERALD SELDON	$1,556.82
11/18/25	1137459	R ALLEN SAUNDERS	$1,094.47

Revolving Fund - Customer Refunds, Incentives and Other			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/18/25	1137460	AN NGUYEN	$734.76
11/18/25	1137461	VIKTORIYA FORTYGIN	$861.84
11/18/25	1137462	CHRISTINE JOHNSON - BRITSCH	$1,817.64
11/18/25	1137463	MARY MARA	$832.32
11/18/25	1137464	JASON RUECKERT	$1,857.87
11/18/25	1137465	SHELLEY MORTINSON	$1,204.56
11/18/25	1137466	EVERETT DE LEON	$1,970.46
11/18/25	1137467	SHARON BAMAGE	$1,163.22
11/18/25	1137468	CORINNE WHITE	$620.76
11/18/25	1137469	ROBERT LEWIS	$1,386.42
11/18/25	1137470	SPEEDWAY CHEVROLET	$7,169.92
11/18/25	1137471	STEVEN GOWEN	$1,087.17
11/18/25	1137472	DONALD BOMBERRY	$978.30
11/18/25	1137473	JENNIFER MANSSON	$644.91
11/18/25	1137474	CURRAN FRITTS	$1,022.07
11/18/25	1137475	JOHN GIBBS	$626.24
11/18/25	1137476	GUARAVKUMAR GANDHI	$2,049.39
11/18/25	1137477	SUSANNAH BANFIELD	$932.58
11/18/25	1137478	DAVID ALLENDER	$1,850.04
11/18/25	1137479	PEGGY WOOD	$538.30
11/18/25	1137480	ROSALINDA SANCHEZ	$1,249.02
11/18/25	1137481	CHARLES KNOEDLER	$367.18
11/18/25	1137482	MICHAEL OLEJNICZAK	$824.67
11/18/25	1137483	ARNOLD LEE	$947.52
11/18/25	1137484	SUJIT VATTENKY	$1,760.36
11/18/25	1137485	BRIAN DEMEERLEER	$2,064.78
11/18/25	1137486	MONICA BERNSTEIN	$1,674.12
11/18/25	1137487	STILLAGUAMISH TRIBE	$33.85
11/18/25	1137488	III MILTON RYE	$1,306.41
11/18/25	1137489	VLAD GONCHAROV	$806.12
11/19/25	1137490	SUMMER SEASONS LLC	$28.25
11/19/25	1137491	SEAN CRANE	$121.42

Revolving Fund - Customer Refunds, Incentives and Other			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/19/25	1137492	KASEY GORDON	$100.26
11/19/25	1137493	JUDITH SWEET-SORGENFREI	$703.22
11/19/25	1137494	20225 BOTHELL, LLC	$16.35
11/19/25	1137495	MARTIN PONNECH	$110.00
11/19/25	1137496	GREEN ACRES PARK INC	$30.26
11/19/25	1137497	AZEEM YARMOHAMMAD	$56.97
11/19/25	1137498	ANNABELLE CAINDOY	$1,019.11
11/19/25	1137499	SAMANTHA VILLEGAS	$907.03
11/19/25	1137500	VOID	$0.00
11/19/25	1137501	WESTERN BLOSSOM HILL INVESTORS, LP	$9.64
11/19/25	1137502	TERRI KNIGHT	$25.00
11/19/25	1137503	MARIE ROSEMBERT	$84.61
11/19/25	1137504	EVERETT HOUSING AUTHORITY	$9.47
11/19/25	1137505	NU TANG	$156.45
11/19/25	1137506	DOUG TWITCHEL	$33.04
11/19/25	1137507	LEONARD WHEELER	$52.00
11/19/25	1137508	DAVID WOOD	$25.85
11/19/25	1137509	JONG KIM	$5.35
11/19/25	1137510	SAMMIE PANCAKE	$31.07
11/19/25	1137511	PHUC DO	$174.18
11/20/25	1137512	RON ANDERSON	$28.84
11/20/25	1137513	PARKVIEW ESTATES FRAZER LLC	$2.44
11/20/25	1137514	KIMBERLY WADE	$8.33
11/20/25	1137515	JANET HEVERAN	$1,040.00
11/20/25	1137516	SHARON BARON	$362.82
11/20/25	1137517	ANA FIGUEROA	$20.39
11/20/25	1137518	CORAL MALEAN	$2,967.10
11/20/25	1137519	WILLIAMS INVESTMENTS I LLC	$22.98
11/20/25	1137520	DARRYL ROGERS	$90.00
11/20/25	1137521	WESTERN BLOSSOM HILL INVESTORS, LP	$22.41
11/20/25	1137522	HECTOR MERCADO	$42.36
11/20/25	1137523	SKANSKA CONSTRUCTORS L300	$208.68

Revolving Fund - Customer Refunds, Incentives and Other			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/20/25	1137524	PATRICIA DERHEIM	$34.74
11/20/25	1137525	JHONATAN CAMILO LIZARAZO GONZALEZ	$102.93
11/20/25	1137526	JON JOHNSON	$29.28
11/20/25	1137527	EVERGREEN GOODWILL	$2,596.83
11/20/25	1137528	MILL CREEK APARTMENTS LLC	$37.19
11/20/25	1137529	XIAOHONG SUN	$48.20
11/20/25	1137530	PATRICK BROWN	$2,200.00
11/20/25	1137531	VOID	$0.00
11/20/25	1137532	MONICA KRISTIANSEN	$21.33
11/21/25	1137533	MASTON PROPERTIES & CONSTRUCTION LLC	$202.66
11/21/25	1137534	SHAHRZAD KHATIBI	$60.35
11/21/25	1137535	NASIAR MAIR	$97.69
11/21/25	1137536	WAKEFIELD ALDERWOOD LLC	$18.14
11/21/25	1137537	FADEHAN OYEBIYI	$550.00
11/21/25	1137538	ANITA SPICER	$133.18
11/21/25	1137539	CEP III-MORNING RUN 13 LLC	$163.63
11/21/25	1137540	TRACY BECKER	$359.31
11/21/25	1137541	MARYSVILLE 136TH ST LLC	$53.37
11/21/25	1137542	DANIEL LYTTON	$131.44
11/21/25	1137543	BRADLEY KING	$45.63
11/21/25	1137544	SUNNARY HENG	$174.17
11/21/25	1137545	KINECT @ LYNNWOOD APARTMENTS, LLC	$17.56
		Total:	**$718,265.17**

Revolving Fund - Electronic Customer Refunds			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/12/25	000531976510	EMMANUEL GHANSAH	$56.84
11/12/25	000531976511	MARA TROWBRIDGE	$84.55
11/12/25	000531976512	CHRISTOPHER ALLEN	$631.83
11/12/25	000531976513	ALDO HERNANDEZ	$80.84
11/12/25	000531976514	OSVALDO LOPEZ-CURIEL	$122.70
11/12/25	000531976515	TINKHANI LUNGU	$24.11
11/12/25	000531976516	HAILEY CRAWFORD	$80.91
11/12/25	000531976517	CRAIG CRAWFORD	$240.59
11/12/25	000531976518	TINKHANI LUNGU	$90.00
11/12/25	000531976519	STEPHEN SAMPSON	$115.05
11/12/25	000531976520	MATTHEW ROOSE	$71.95
11/12/25	000531976521	JUDITH SWEET-SORGENFREI	$185.00
11/17/25	000532021886	GLEBERSON DANTASLIMA	$11.42
11/17/25	000532021887	MICHAEL MOORE	$20.00
11/17/25	000532021888	MISTY TINO	$150.49
11/17/25	000532021889	RODOLFO OROZCO	$81.49
11/17/25	000532021890	MICHAEL MOORE	$102.36
11/17/25	000532021891	MICHAEL MOORE	$101.27
11/17/25	000532021892	GEORGE OTIENO	$123.30
11/17/25	000532021893	GLEBERSON DANTASLIMA	$160.00
11/18/25	000532034147	DONALD HARDIN	$489.83
11/18/25	000532034148	TANYA LOPEZ	$413.38
11/18/25	000532034149	VICTOR DO	$5.32
11/18/25	000532034150	ISABELLA COSTA	$8.52
11/18/25	000532034151	BERTA PATRISIA HERNANDEZ	$17.72
11/18/25	000532034152	JENNIFER WATKINS	$43.01
11/18/25	000532034153	JOSE LOPEZ CASTELLANOS	$76.29
11/20/25	000532055450	JOSE DANIEL RANGEL VALERO	$112.73
11/20/25	000532055451	EDWARD W CLENDENNING	$77.00
11/20/25	000532055452	HAYLIE SEMAYS KRALL	$96.17
11/20/25	000532055453	ALEXANDER PALMER	$94.00
11/20/25	000532055454	FRANCIS DECAIRES	$30.13

Revolving Fund - Electronic Customer Refunds			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/20/25	000532055455	GABRIEL DE JESUS ALTAMIRANO DAVILA	$77.55
11/20/25	000532055456	SHAEFER NIELSON	$91.74
11/20/25	000532055457	NORA RICE	$54.03
11/20/25	000532055458	PHONG BUI	$26.30
11/20/25	000532055459	AIUR TCYRENOV	$98.38
11/20/25	000532055460	OSCAR BERRIOS MUNOZ	$118.92
11/20/25	000532055461	LI XU	$117.43
11/20/25	000532055462	JOSE DANIEL RANGEL VALERO	$178.37
		Total:	**$4,761.52**

Accounts Payable Warrants			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/13/25	8084511	JIM LUSSIER	$16,679.98
11/13/25	8084512	AT&T CORP	$67,599.57
11/13/25	8084513	CLACKAMAS COUNTY TAX COLLECTOR	$3,004.01
11/13/25	8084514	DESCHUTES COUNTY TAX COLLECTOR	$2,347.24
11/13/25	8084515	DUNN LUMBER CO INC	$275.18
11/13/25	8084516	CITY OF EVERETT	$242.48
11/13/25	8084517	JACKSON COUNTY TAXATION OFFICE	$1,791.52
11/13/25	8084518	JEFFERSON COUNTY TAX COLLECTOR	$5,471.21
11/13/25	8084519	LAKE COUNTY TAX COLLECTOR	$5,409.46
11/13/25	8084520	LANE COUNTY TAX COLLECTOR	$2,621.97
11/13/25	8084521	LINN COUNTY TAX COLLECTOR	$2,684.99
11/13/25	8084522	GENUINE PARTS COMPANY	$1,733.27
11/13/25	8084523	PAPE MACHINERY INC	$392.51
11/13/25	8084524	PITNEY BOWES INC	$353.34
11/13/25	8084525	REID MIDDLETON INC	$1,590.00
11/13/25	8084526	REPUBLIC SERVICES INC	$1,285.87
11/13/25	8084527	SCADA AND CONTROLS ENGINEERING INC	$15,685.00
11/13/25	8084528	SHERMAN COUNTY TAX COLLECTOR	$8,875.50
11/13/25	8084529	SILVER LAKE WATER & SEWER DISTRICT	$112.19
11/13/25	8084530	SIX ROBBLEES INC	$13.76
11/13/25	8084531	SKAGIT LAW GROUP PLLC	$1,050.00
11/13/25	8084532	SOUND PUBLISHING INC	$167.58
11/13/25	8084533	WAGNER SMITH EQUIPMENT CO	$26,115.14
11/13/25	8084534	WASCO COUNTY TAX COLLECTOR	$9,302.68
11/13/25	8084535	WASTE MANAGEMENT OF WASHINGTON INC	$1,503.22
11/13/25	8084536	ZORO TOOLS INC	$410.54
11/13/25	8084537	BICKFORD MOTORS INC	$2,008.50
11/13/25	8084538	CROOK COUNTY TAX COLLECTOR	$2,880.14
11/13/25	8084539	CROSS VALLEY WATER DISTRICT	$288.05
11/13/25	8084540	DOUGLAS COUNTY TAX COLLECTOR	$2,347.13
11/13/25	8084541	THE HO SEIFFERT COMPANY	$3,975.00
11/13/25	8084542	JEFFREY HATHAWAY	$54.84

Accounts Payable Warrants			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/13/25	8084543	KLAMATH COUNTY TAX COLLECTOR	$2,363.16
11/13/25	8084544	MARION COUNTY TAX COLLECTOR	$2,138.02
11/13/25	8084545	MESA STANDARDS ALLIANCE	$15,000.00
11/13/25	8084546	ROOSEVELT WATER ASSN INC	$154.00
11/13/25	8084547	SNOHOMISH COUNTY	$252.35
11/13/25	8084548	CITY OF STANWOOD	$1,677.88
11/13/25	8084549	STANWOOD REDI MIX INC	$4,173.08
11/13/25	8084550	STRUCTURED COMMUNICATION SYSTEMS IN	$189.98
11/13/25	8084551	WYNNE AND SONS INC	$79.13
11/13/25	8084552	CITY OF EVERETT	$1,767.74
11/13/25	8084553	ROOTS FORESTRY CONSULTING LLC	$21,854.75
11/13/25	8084554	WASHINGTON CRANE & HOIST LLC	$21,461.31
11/13/25	8084555	THE PAPE GROUP INC	$5,335.65
11/13/25	8084556	AG ENTERPRISE SUPPLY INC	$815.89
11/13/25	8084557	OCCUPATIONAL HEALTH CENTERS OF WA P	$727.00
11/13/25	8084558	NORTHWEST FIBER LLC	$28,532.32
11/13/25	8084559	KENDALL DEALERSHIP HOLDINGS LLC	$248.85
11/13/25	8084560	REFTEK SYSTEMS INC	$1,200.00
11/13/25	8084561	CINTAS CORPORATION NO 2	$7,444.69
11/13/25	8084562	DAY PITNEY LLP	$4,355.00
11/13/25	8084563	SOLID WASTE SYSTEMS	$282,197.03
11/13/25	8084564	APEX MECHANICAL LLC	$198,685.85
11/13/25	8084565	GLASS SPECIALISTS INC	$194.00
11/13/25	8084566	SUPERIOR GLASS INSTALLATIONS INC	$2,941.88
11/13/25	8084567	PARAGON HEATING AND HOME	$1,975.00
11/13/25	8084568	A & E INSULATION INC	$2,247.75
11/18/25	8084569	SANDRA GARDINER	$440.00
11/18/25	8084570	COMCAST HOLDING CORPORATION	$248.00
11/18/25	8084571	CITY OF DARRINGTON	$6,853.11
11/18/25	8084572	CITY OF GOLD BAR	$11,209.41
11/18/25	8084573	CITY OF GOLD BAR	$703.37
11/18/25	8084574	CORE & MAIN LP	$13,907.05

Accounts Payable Warrants			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/18/25	8084575	CITY OF LYNNWOOD	$459.36
11/18/25	8084576	CITY OF MARYSVILLE	$189,961.91
11/18/25	8084577	CITY OF MARYSVILLE	$105.26
11/18/25	8084578	CITY OF MONROE	$1,369.57
11/18/25	8084579	CITY OF MOUNTLAKE TERRACE	$69,371.46
11/18/25	8084580	CITY OF MOUNTLAKE TERRACE	$398.26
11/18/25	8084581	GENUINE PARTS COMPANY	$1,881.94
11/18/25	8084582	PACIFIC SAFETY SUPPLY INC	$3,217.31
11/18/25	8084583	INFINITE ELECTRONICS INTRNTL INC	$1,000.76
11/18/25	8084584	REPUBLIC SERVICES INC	$437.25
11/18/25	8084585	SNOHOMISH COUNTY	$307.50
11/18/25	8084586	SOUND PUBLISHING INC	$132.30
11/18/25	8084587	SEPTIC SERVICES INC	$2,179.58
11/18/25	8084588	CITY OF SULTAN	$31,696.92
11/18/25	8084589	UNUM LIFE INSURANCE CO OF AMERICA	$36,604.40
11/18/25	8084590	WASTE MANAGEMENT OF WASHINGTON INC	$799.93
11/18/25	8084591	ALDERWOOD WATER & WASTEWATER DISTRI	$192.73
11/18/25	8084592	CITY OF ARLINGTON	$143,621.55
11/18/25	8084593	BICKFORD MOTORS INC	$1,779.72
11/18/25	8084594	CITY OF BOTHELL	$116,968.72
11/18/25	8084595	CITY OF BRIER	$17,766.69
11/18/25	8084596	EBEY HILL HYDROELECTRIC INC	$719.92
11/18/25	8084597	CITY OF EDMONDS	$141,889.05
11/18/25	8084598	JEFFREY HATHAWAY	$65.89
11/18/25	8084599	CITY OF INDEX	$774.15
11/18/25	8084600	GARY D KREIN	$1,978.20
11/18/25	8084601	CITY OF LAKE STEVENS	$115,232.50
11/18/25	8084602	CITY OF LAKE STEVENS	$53,990.87
11/18/25	8084603	CITY OF MONROE	$84,159.04
11/18/25	8084604	CITY OF STANWOOD	$32,004.34
11/18/25	8084605	TOWN OF WOODWAY	$6,133.69
11/18/25	8084606	CITY OF GRANITE FALLS	$16,269.26

Accounts Payable Warrants			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/18/25	8084607	CASCADE COLLISION CENTER INC	$9,600.11
11/18/25	8084608	THE PAPE GROUP INC	$3,518.48
11/18/25	8084609	CITY OF EVERETT	$629,051.85
11/18/25	8084610	OCCUPATIONAL HEALTH CENTERS OF WA P	$260.50
11/18/25	8084611	BCC SOFTWARE LLC	$4,126.50
11/18/25	8084612	CRAWFORD & COMPANY	$2,439.76
11/18/25	8084613	WASHINGTON STATE DOT	$394.00
11/18/25	8084614	KENDALL DEALERSHIP HOLDINGS LLC	$126.84
11/18/25	8084615	BAXTER AUTO PARTS INC	$1,450.68
11/18/25	8084616	THE PAPE GROUP	$6,780.02
11/18/25	8084617	NORTHWEST FIBER LLC	$120.00
11/18/25	8084618	CITY OF EVERETT	$350,000.00
11/18/25	8084619	KENDALL DEALERSHIP HOLDINGS LLC	$1,035.32
11/18/25	8084620	EVANGELICAL CHINESE CHURCH	$4,308.00
11/18/25	8084621	PRO TECH M ELECTRIC LLC	$3,174.38
11/18/25	8084622	CAPITAL LIGHTING COMPANY INC	$255.02
11/18/25	8084623	CITY OF LYNNWOOD	$195,787.65
11/18/25	8084624	CITY OF MUKILTEO	$85,180.64
11/18/25	8084625	CITY OF SNOHOMISH	$41,500.06
11/18/25	8084626	SUPERIOR GLASS INSTALLATIONS INC	$2,021.13
11/18/25	8084627	PARAGON HEATING AND HOME	$1,975.00
11/18/25	8084628	HAUSMEISTER HOME SERVICES INC	$2,560.00
11/20/25	8084629	FULLWILER CONSTRUCTION INC	$27,993.63
11/20/25	8084630	BRETT WILSON	$275.00
11/20/25	8084631	JENNIFER HSIAO	$5,662.56
11/20/25	8084632	CONSERVICE, LLC	$4,634.03
11/20/25	8084633	COMCAST HOLDING CORPORATION	$284.36
11/20/25	8084634	CITY OF EVERETT	$112.89
11/20/25	8084635	FIDALGO PAVING & CONSTRUCTION LLC	$103,433.95
11/20/25	8084636	CITY OF LYNNWOOD	$1,072.91
11/20/25	8084637	CITY OF MARYSVILLE	$168.97
11/20/25	8084638	GENUINE PARTS COMPANY	$1,528.89

Accounts Payable Warrants			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/20/25	8084639	PITNEY BOWES INC	$564.35
11/20/25	8084640	REPUBLIC SERVICES INC	$2,316.02
11/20/25	8084641	SNOHOMISH COUNTY	$10,932.00
11/20/25	8084642	SOUND PUBLISHING INC	$241.08
11/20/25	8084643	SEPTIC SERVICES INC	$809.25
11/20/25	8084644	WASHINGTON STATE	$300.00
11/20/25	8084645	BICKFORD MOTORS INC	$2,633.03
11/20/25	8084646	JKA ENTERPRISES INC	$285.10
11/20/25	8084647	LAKE STEVENS SEWER DIST	$291.21
11/20/25	8084648	GHB WINDOW CLEANING SERVICES INC	$19,258.38
11/20/25	8084649	MARTIN ENERGY GROUP SERVICES LLC	$103,633.61
11/20/25	8084650	LINKEDIN CORP	$23,903.25
11/20/25	8084651	ROGER BELL REAL ESTATE HOLDINGS	$6,365.40
11/20/25	8084652	CONSERVE ENERGY LLC	$16,170.07
11/20/25	8084653	SKAGIT BONDED COLLECTORS LLC	$1,405.89
11/20/25	8084654	RAYMOND HANDLING CONCEPTS CORP	$76,171.44
11/20/25	8084655	PORT OF EVERETT	$6,597.44
11/20/25	8084656	RELIANCE US HOLDINGS II LLC	$2,175.00
		Total:	**$3,668,000.80**

Accounts Payable ACH			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/10/25	6059772	GLOBAL RENTAL COMPANY INC	$195,664.24
11/10/25	6059773	HOWARD INDUSTRIES INC	$44,074.30
11/10/25	6059774	NEWARK CORP	$29.59
11/10/25	6059775	PTC INC	$1,104.09
11/10/25	6059776	PUGET SOUND ENERGY INC	$21.56
11/10/25	6059777	RWC INTERNATIONAL LTD	$386.94
11/10/25	6059778	S&C ELECTRIC COMPANY	$4,010.26
11/10/25	6059779	SHI INTERNATIONAL CORP	$8,501.44
11/10/25	6059780	STAR RENTALS INC	$5,853.44
11/10/25	6059781	STELLA-JONES CORPORATION	$34,986.71
11/10/25	6059782	TOPSOILS NORTHWEST INC	$1,056.00
11/10/25	6059783	CUZ CONCRETE PRODUCTS INC	$1,903.56
11/10/25	6059784	GENERAL PACIFIC INC	$8,704.08
11/10/25	6059785	LONE MOUNTAIN COMMUNICATIONS LLC	$36,348.75
11/10/25	6059786	NORTHWEST CASCADE INC	$290.50
11/10/25	6059787	ROHLINGER ENTERPRISES INC	$6,925.68
11/10/25	6059788	SENSUS USA INC	$114,570.75
11/10/25	6059789	SOUND SAFETY PRODUCTS CO INC	$384.82
11/10/25	6059790	WALTER E NELSON CO OF WESTERN WA	$29,318.44
11/10/25	6059791	ALTEC INDUSTRIES INC	$1,501.34
11/10/25	6059792	ANIXTER INC	$48,444.80
11/10/25	6059793	CG ENGINEERING PLLC	$77.50
11/10/25	6059794	MOTION & FLOW CONTROL PRODUCTS INC	$967.48
11/10/25	6059795	TRAFFIC CONTROL PLAN CO OF WA LLC	$875.00
11/10/25	6059796	MCWANE INC	$61,206.20
11/10/25	6059797	ANDREW JORDAN HARPER	$2,245.20
11/10/25	6059798	RESOURCE INNOVATIONS INC	$64,964.50
11/10/25	6059799	LISTEN AUDIOLOGY SERVICES INC	$660.00
11/10/25	6059800	FLEET SERVICE VEHICLE REPAIR LLC	$1,118.74
11/10/25	6059801	PUGET SOUND HARDWARE INC	$1,202.22
11/10/25	6059802	ALEXANDRA LEGARE	$2,874.60
11/10/25	6059803	RACOM CORPORATION	$434,707.10

Accounts Payable ACH			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/10/25	6059804	JAMIE KISS	$1,741.40
11/10/25	6059805	RODDAN INDUSTRIAL LLC	$37,690.49
11/10/25	6059806	ONEPLAN PORTFOLIO SOLUTIONS LLC	$4,890.10
11/10/25	6059807	TESSCO TECHNOLOGIES INC	$67.69
11/10/25	6059808	EUROFINS ENVR TESTING AMERICA HOLDI	$182.00
11/10/25	6059809	SEPTIC SOLUTIONS LLC	$512.53
11/10/25	6059810	HOME COMFORT ALLIANCE LLC	$5,050.00
11/10/25	6059811	BLACK FOREST INSULATION LLC	$2,241.00
11/10/25	6059812	DAVID CROSS	$1,811.42
11/10/25	6059813	CASEY WRIGHT	$175.00
11/10/25	6059814	JULIE MAINSTONE	$241.01
11/10/25	6059815	CHRISTOPHER BRITSCH	$2,037.19
11/10/25	6059816	CHRISTINA BRUECKNER	$337.40
11/10/25	6059817	ZACHARY SCOTT	$1,879.33
11/10/25	6059818	ALEXANDER CHOREY	$613.72
11/10/25	6059819	SUZANNE OVERSVEE	$709.92
11/10/25	6059820	CHRISTOPHER SABELLA	$124.00
11/10/25	6059821	BRANDA ANDRADE	$328.00
11/10/25	6059822	BRANDON PHAN	$100.00
11/10/25	6059823	WENDY VLAHOVICH	$1,834.05
11/10/25	6059824	JOSIE ANDERSON	$92.40
11/10/25	6059825	KEVIN PRESLER	$955.90
11/10/25	6059826	JENNIFER RICH	$60.00
11/10/25	6059827	SHAWN WIGGINS	$50.40
11/10/25	6059828	DYANEE BOUTON	$1,131.22
11/10/25	6059829	DANE MORTON	$319.20
11/10/25	6059830	RYAN RODORIGO	$175.00
11/10/25	6059831	TRAVIS WITTERS	$659.80
11/10/25	6059832	SHAWN HUNSTOCK	$965.34
11/12/25	6059833	DAVID EVANS & ASSOCIATES INC	$24,547.90
11/12/25	6059834	FASTENAL COMPANY	$2,491.54
11/12/25	6059835	HOWARD INDUSTRIES INC	$36,014.23

Accounts Payable ACH			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/12/25	6059836	NORTH COAST ELECTRIC COMPANY	$879.24
11/12/25	6059837	NORTHSTAR CHEMICAL INC	$2,454.26
11/12/25	6059838	ROMAINE ELECTRIC CORP	$257.83
11/12/25	6059839	RWC INTERNATIONAL LTD	$4,864.57
11/12/25	6059840	STELLAR INDUSTRIAL SUPPLY INC	$5,268.41
11/12/25	6059841	TOPSOILS NORTHWEST INC	$1,188.00
11/12/25	6059842	GORDON TRUCK CENTERS INC	$169.37
11/12/25	6059843	VAN NESS FELDMAN LLP	$880.00
11/12/25	6059844	COLEHOUR & COHEN INC	$106,929.00
11/12/25	6059845	GENERAL PACIFIC INC	$15,422.33
11/12/25	6059846	MERCURY FITNESS REPAIR INC	$942.23
11/12/25	6059847	NORTHWEST HANDLING SYSTEMS INC	$845.15
11/12/25	6059848	NW TRANSMISSION INC	$4,439.23
11/12/25	6059849	BEN-KO-MATIC CO	$6,497.19
11/12/25	6059850	PACO VENTURES LLC	$2,752.17
11/12/25	6059851	POWER ENGINEERS INC	$353.50
11/12/25	6059852	LOUIS F MATHESON CONSTRUCTION INC	$3,028.68
11/12/25	6059853	SENSUS USA INC	$103,031.25
11/12/25	6059854	SNOHOMISH COUNTY	$78,119.85
11/12/25	6059855	SOUND SAFETY PRODUCTS CO INC	$992.40
11/12/25	6059856	TOTAL LANDSCAPE CORP	$16,730.77
11/12/25	6059857	TYNDALE ENTERPRISES INC	$14,072.93
11/12/25	6059858	ALTEC INDUSTRIES INC	$962.27
11/12/25	6059859	ANIXTER INC	$15,918.41
11/12/25	6059860	FABER CONSTRUCTION CORP	$343,191.43
11/12/25	6059861	MOTION & FLOW CONTROL PRODUCTS INC	$158.14
11/12/25	6059862	TRAFFIC CONTROL PLAN CO OF WA LLC	$175.00
11/12/25	6059863	RESOURCE INNOVATIONS INC	$27,767.00
11/12/25	6059864	CURTIS A SMITH	$19,478.68
11/12/25	6059865	HM PACIFIC NORTHWEST INC	$2,490.21
11/12/25	6059866	TRC ENGINEERS INC	$759,764.60
11/12/25	6059867	CAL-LINE NORTHWEST LLC	$207.68

Accounts Payable ACH			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/12/25	6059868	STUART C IRBY COMPANY	$3,819.03
11/12/25	6059869	QUALUS LLC	$89,704.25
11/12/25	6059870	NORTH AMERICAN RESCUE HOLDINGS LLC	$909.80
11/12/25	6059871	TOYOTA MATERIAL HANDLING NW INC	$3,842.35
11/12/25	6059872	AMERICAN CRAWLSPACE & PEST SERVICES	$390.00
11/12/25	6059873	COZY HEATING INC	$11,300.00
11/12/25	6059874	GOLDFINCH BROTHERS INC	$200.00
11/12/25	6059875	GREEN BUILT NORTHWEST LLC	$475.00
11/12/25	6059876	CHERI NELSON	$114.80
11/12/25	6059877	LILLIAN MANLEY	$1,026.00
11/12/25	6059878	COURTNEY KINGERY	$25.00
11/12/25	6059879	MATTHEW OTTEN	$404.91
11/12/25	6059880	STEPHEN FULLUM	$58.80
11/13/25	6059881	ASPLUNDH TREE EXPERT LLC	$60,620.87
11/13/25	6059882	DAVID EVANS & ASSOCIATES INC	$761.00
11/13/25	6059883	RWC INTERNATIONAL LTD	$752.67
11/13/25	6059884	TOPSOILS NORTHWEST INC	$845.13
11/13/25	6059885	STATE OF WASHINGTON	$7,920.13
11/13/25	6059886	RS AMERICAS INC	$93.01
11/13/25	6059887	DUNLAP INDUSTRIAL HARDWARE INC	$12,287.92
11/13/25	6059888	NORTHWEST CASCADE INC	$202.50
11/13/25	6059889	RICOH USA INC	$2,938.52
11/13/25	6059890	SOUND SAFETY PRODUCTS CO INC	$8,131.40
11/13/25	6059891	TECHPOWER SOLUTIONS INC	$17,693.90
11/13/25	6059892	TYNDALE ENTERPRISES INC	$1,062.21
11/13/25	6059893	ALTEC INDUSTRIES INC	$10,227.53
11/13/25	6059894	ICONIX WATERWORKS INC	$14,003.66
11/13/25	6059895	MOTION & FLOW CONTROL PRODUCTS INC	$46.05
11/13/25	6059896	MOUSER ELECTRONICS INC	$15.21
11/13/25	6059897	WELLNESS BY WISHLIST INC	$1,674.54
11/13/25	6059898	ALAN L MONSON	$292.33
11/13/25	6059899	AMBERBOX INC	$5,361.62

Accounts Payable ACH			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/13/25	6059900	GLASS FIX LLC	$1,340.78
11/13/25	6059901	NOKIA OF AMERICA CORP	$544.01
11/13/25	6059902	MOBILIZZ USA INC	$384.03
11/13/25	6059903	MICHAEL COE	$114.60
11/13/25	6059904	JEFFREY FEINBERG	$114.60
11/14/25	6059905	HOWARD INDUSTRIES INC	$108,042.69
11/14/25	6059906	S&C ELECTRIC COMPANY	$4,465.24
11/14/25	6059907	STAR RENTALS INC	$2,566.05
11/14/25	6059908	TOPSOILS NORTHWEST INC	$299.42
11/14/25	6059909	WIDENET CONSULTING GROUP LLC	$2,130.40
11/14/25	6059910	NORTHWEST CASCADE INC	$167.00
11/14/25	6059911	EXCHANGEIT GROUP LLC	$240.41
11/14/25	6059912	LOOMIS ARMORED US LLC	$3,978.21
11/17/25	6059913	ALASKAN COPPER & BRASS CO	$2,656.94
11/17/25	6059914	ASPLUNDH TREE EXPERT LLC	$3,816.00
11/17/25	6059915	CLEAN HARBORS ENVIRONMENTAL	$421.56
11/17/25	6059916	COMMERCIAL FILTER SALES & SERVICE	$19,394.38
11/17/25	6059917	CONSOLIDATED ELECTRICAL DISTRIBUTOR	$1,992.27
11/17/25	6059918	HOWARD INDUSTRIES INC	$178,950.17
11/17/25	6059919	PACIFIC POWER GROUP LLC	$2,782.34
11/17/25	6059920	PETROCARD INC	$52,950.28
11/17/25	6059921	ROBERT HALF INC	$10,120.00
11/17/25	6059922	RWC INTERNATIONAL LTD	$416.05
11/17/25	6059923	SHI INTERNATIONAL CORP	$2,479.01
11/17/25	6059924	STELLAR INDUSTRIAL SUPPLY INC	$409.14
11/17/25	6059925	STELLA-JONES CORPORATION	$36,609.56
11/17/25	6059926	TOPSOILS NORTHWEST INC	$3,564.00
11/17/25	6059927	VAN NESS FELDMAN LLP	$5,417.00
11/17/25	6059928	BRAKE & CLUTCH SUPPLY INC	$1,495.89
11/17/25	6059929	CELLCO PARTNERSHIP	$1,924.65
11/17/25	6059930	DESIGNER DECAL INC	$1,257.26
11/17/25	6059931	DUNLAP INDUSTRIAL HARDWARE INC	$299.68

Accounts Payable ACH			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/17/25	6059932	BRIAN DAVIS ENTERPRISES INC	$8,383.06
11/17/25	6059933	MILLIMAN INC	$2,187.01
11/17/25	6059934	NORTHWEST CASCADE INC	$304.50
11/17/25	6059935	ROHLINGER ENTERPRISES INC	$2,124.51
11/17/25	6059936	RUBATINO REFUSE REMOVAL LLC	$9,033.99
11/17/25	6059937	BRENT STAINER	$450.00
11/17/25	6059938	T-MOBILE USA INC	$677.03
11/17/25	6059939	TOTAL LANDSCAPE CORP	$328.50
11/17/25	6059940	WESTERN SAFETY PRODUCTS INC	$873.72
11/17/25	6059941	WESTERN PACIFIC CRANE & EQUIP LLC	$430.95
11/17/25	6059942	GRAYBAR ELECTRIC CO INC	$319.02
11/17/25	6059943	ALTEC INDUSTRIES INC	$5,490.87
11/17/25	6059944	ANIXTER INC	$34,359.93
11/17/25	6059945	SEATTLE NUT & BOLT LLC	$1,345.73
11/17/25	6059946	MOTION & FLOW CONTROL PRODUCTS INC	$3,741.68
11/17/25	6059947	TRAFFIC CONTROL PLAN CO OF WA LLC	$1,050.00
11/17/25	6059948	WILLDAN ENERGY SOLUTIONS INC	$22,375.44
11/17/25	6059949	AON CONSULTING INC	$10,000.00
11/17/25	6059950	OPENSQUARE HOLDINGS LLC	$2,719.09
11/17/25	6059951	HM PACIFIC NORTHWEST INC	$968.79
11/17/25	6059952	BORDER STATES INDUSTRIES INC	$25,059.48
11/17/25	6059953	UNIT PROCESS COMPANY	$2,815.85
11/17/25	6059954	SUNBELT RENTALS INC	$931.76
11/17/25	6059955	PERFORMANCE SYSTEMS	$300,000.00
11/17/25	6059956	STUART C IRBY COMPANY	$95,547.06
11/17/25	6059957	TOYOTA MATERIAL HANDLING NW INC	$3,976.01
11/17/25	6059958	KEITHLY BARBER ASSOCIATES INC	$8,179.90
11/17/25	6059959	EUROFINS ENVR TESTING AMERICA HOLDI	$468.00
11/17/25	6059960	STALLION INFRASTRUCTURE SERVICES LL	$110.00
11/18/25	6059961	CARDINAL PAINT & POWDER INC	$95.06
11/18/25	6059962	HOWARD INDUSTRIES INC	$35,640.57
11/18/25	6059963	NELSON DISTRIBUTING INC	$8,080.51

Accounts Payable ACH			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/18/25	6059964	SCHWEITZER ENGINEERING LAB INC	$33,002.97
11/18/25	6059965	STELLAR INDUSTRIAL SUPPLY INC	$1,630.79
11/18/25	6059966	TOPSOILS NORTHWEST INC	$924.00
11/18/25	6059967	TFS ENERGY LLC	$925.00
11/18/25	6059968	TRENCHLESS CONSTR SVCS LLC	$26,495.18
11/18/25	6059969	TULLETT PREBON AMERICAS CORP	$1,000.00
11/18/25	6059970	UNITED PARCEL SERVICE	$482.47
11/18/25	6059971	DOBBS HEAVY DUTY HOLDINGS LLC	$666.50
11/18/25	6059972	DESIGNER DECAL INC	$5,502.14
11/18/25	6059973	LENZ ENTERPRISES INC	$158.50
11/18/25	6059974	NVL LABORATORIES INC	$191.00
11/18/25	6059975	QUALCO ENERGY	$37,250.13
11/18/25	6059976	RUBATINO REFUSE REMOVAL LLC	$611.50
11/18/25	6059977	TOTAL LANDSCAPE CORP	$10,633.52
11/18/25	6059978	UNITED RENTALS NORTH AMERICA INC	$707.20
11/18/25	6059979	ALTEC INDUSTRIES INC	$1,086.67
11/18/25	6059980	ANIXTER INC	$37,925.82
11/18/25	6059981	TRAFFIC CONTROL PLAN CO OF WA LLC	$1,925.00
11/18/25	6059982	HARMSEN LLC	$1,467.50
11/18/25	6059983	ARNETT INDUSTRIES LLC	$12,779.70
11/18/25	6059984	BORDER STATES INDUSTRIES INC	$156,635.69
11/18/25	6059985	WALTER E NELSON OF N WASHINGTON	$952.16
11/18/25	6059986	TOYOTA MATERIAL HANDLING NW INC	$586.97
11/18/25	6059987	LUMEN TACTICAL LLC	$554.89
11/18/25	6059988	TESSCO TECHNOLOGIES INC	$1,921.50
11/18/25	6059989	EUROFINS ENVR TESTING AMERICA HOLDI	$208.00
11/18/25	6059990	AMERICAN CRAWLSPACE & PEST SERVICES	$2,529.00
11/18/25	6059991	COZY HEATING INC	$8,625.00
11/18/25	6059992	GREEN LIGHTING LLC	$10,978.93
11/18/25	6059993	HOME COMFORT ALLIANCE LLC	$2,875.00
11/18/25	6059994	SUPER ATTIC SOLUTIONS INC	$1,599.00
11/19/25	6059995	ALASKAN COPPER & BRASS CO	$330.12

Accounts Payable ACH			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/19/25	6059996	COMMERCIAL FILTER SALES & SERVICE	$1,009.15
11/19/25	6059997	DAVID EVANS & ASSOCIATES INC	$1,675.00
11/19/25	6059998	GLOBAL RENTAL COMPANY INC	$10,469.00
11/19/25	6059999	INTEGRA CLEAR CO	$4,394.19
11/19/25	6060000	NORTHSTAR CHEMICAL INC	$3,329.15
11/19/25	6060001	NORTHWEST POWER POOL CORP	$8,402.51
11/19/25	6060002	ROMAINE ELECTRIC CORP	$4,612.75
11/19/25	6060003	RWC INTERNATIONAL LTD	$899.88
11/19/25	6060004	SUBURBAN PROPANE LP	$774.62
11/19/25	6060005	TOPSOILS NORTHWEST INC	$528.00
11/19/25	6060006	MAINTENANCE RESELLER CORPORATION	$4,264.12
11/19/25	6060007	NORTHWEST HANDLING SYSTEMS INC	$54,086.32
11/19/25	6060008	PACO VENTURES LLC	$1,985.99
11/19/25	6060009	PORTAGE BAY SOLUTIONS INC	$562.14
11/19/25	6060010	SOUND SAFETY PRODUCTS CO INC	$2,285.48
11/19/25	6060011	TOTAL LANDSCAPE CORP	$447.50
11/19/25	6060012	ULINE INC	$66.76
11/19/25	6060013	WALTER E NELSON CO OF WESTERN WA	$647.79
11/19/25	6060014	SHERMAN & REILLY INC	$1,485.31
11/19/25	6060015	ANIXTER INC	$491.52
11/19/25	6060016	ATWORK COMMERCIAL ENTERPRISES LLC	$10,427.88
11/19/25	6060017	TARREN ACKERMANN	$425.97
11/19/25	6060018	FS COM INC	$1,806.76
11/19/25	6060019	CURALINC LLC	$3,630.00
11/19/25	6060020	EUROFINS ENVR TESTING AMERICA HOLDI	$130.00
11/19/25	6060021	TRAVIS RIFE	$175.00
11/19/25	6060022	VERONICA BLACK	$167.00
11/20/25	6060023	ASPLUNDH TREE EXPERT LLC	$68,871.03
11/20/25	6060024	DAVEY TREE SURGERY COMPANY	$19,397.05
11/20/25	6060025	EJ BROOKS COMPANY	$23,561.22
11/20/25	6060026	IBEW LOCAL 77	$103,727.60
11/20/25	6060027	JACO ANALYTICAL LAB INC	$549.41

Accounts Payable ACH			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/20/25	6060028	NELSON DISTRIBUTING INC	$169.37
11/20/25	6060029	NORTH COAST ELECTRIC COMPANY	$6,637.53
11/20/25	6060030	ROMAINE ELECTRIC CORP	$315.19
11/20/25	6060031	RWC INTERNATIONAL LTD	$239.11
11/20/25	6060032	SCHNEIDER ELECTRIC USA INC	$21,122.33
11/20/25	6060033	SCHWEITZER ENGINEERING LAB INC	$424.39
11/20/25	6060034	TOPSOILS NORTHWEST INC	$264.00
11/20/25	6060035	TRENCHLESS CONSTR SVCS LLC	$39,462.26
11/20/25	6060036	GORDON TRUCK CENTERS INC	$547.41
11/20/25	6060037	DOBBS HEAVY DUTY HOLDINGS LLC	$208.80
11/20/25	6060038	DICKS TOWING INC	$778.76
11/20/25	6060039	SOUND SAFETY PRODUCTS CO INC	$2,899.46
11/20/25	6060040	TECH PRODUCTS INC	$480.00
11/20/25	6060041	TRIANGLE ASSOCIATES INC	$2,982.61
11/20/25	6060042	TYNDALE ENTERPRISES INC	$19,930.82
11/20/25	6060043	WESTERN SAFETY PRODUCTS INC	$20,183.14
11/20/25	6060044	WESTERN PACIFIC CRANE & EQUIP LLC	$2,841.40
11/20/25	6060045	ALTEC INDUSTRIES INC	$46.08
11/20/25	6060046	ICONIX WATERWORKS INC	$4,718.49
11/20/25	6060047	JTI COMMERCIAL SERVICES LLC	$409.10
11/20/25	6060048	DS SERVICES OF AMERICA INC	$7.48
11/20/25	6060049	OPENSQUARE HOLDINGS LLC	$3,079.53
11/20/25	6060050	PACHECOS LANDSCAPING LLC	$21,290.40
11/20/25	6060051	RODDAN INDUSTRIAL LLC	$48,288.77
11/20/25	6060052	CUSTOM TRUCK ONE SOURCE INC	$11,175.03
11/20/25	6060053	TOYOTA MATERIAL HANDLING NW INC	$1,305.02
11/20/25	6060054	EUROFINS ENVR TESTING AMERICA HOLDI	$260.00
11/20/25	6060055	ALAMON INC	$133,675.67
11/20/25	6060056	MOBILIZZ USA INC	$194.75
11/20/25	6060057	SUPER ATTIC SOLUTIONS INC	$2,187.00
11/20/25	6060058	JOHN WATSON	$124.00
11/20/25	6060059	MISTY STEVENS	$238.69

Accounts Payable ACH			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/20/25	6060060	JASON ZYSKOWSKI	$418.65
11/20/25	6060061	ANDREA DUFFY	$25.00
11/20/25	6060062	SINH TRAN	$76.80
11/20/25	6060063	JAMES MARTIN	$142.00
11/20/25	6060064	RYAN ZIEGLER	$25.00
11/20/25	6060065	GENEVIEVE BARNHART	$547.08
11/20/25	6060066	ANGELA MICHAELSON	$568.12
11/20/25	6060067	ALLISON PHILLIPS	$271.20
11/20/25	6060068	NICHOLAS PERETTI	$566.10
11/20/25	6060069	KELSEY LEWIS	$521.75
11/20/25	6060070	ORION EATON	$346.27
11/20/25	6060071	ROBERTA CHRISTMANN CAVEDON	$33.60
11/21/25	6060072	D HITTLE & ASSOCIATES INC	$9,258.32
11/21/25	6060073	HOWARD INDUSTRIES INC	$71,098.71
11/21/25	6060074	PUGET SOUND ENERGY INC	$1,085.01
11/21/25	6060075	RWC INTERNATIONAL LTD	$2,999.63
11/21/25	6060076	S&C ELECTRIC COMPANY	$71,713.05
11/21/25	6060077	WIDENET CONSULTING GROUP LLC	$2,098.06
11/21/25	6060078	PACIFIC MOBILE STRUCTURES INC	$1,348.76
11/21/25	6060079	DS SERVICES OF AMERICA INC	$158.57
11/21/25	6060080	OPENSQUARE HOLDINGS LLC	$673.45
11/21/25	6060081	AA REMODELING LLC	$1,539.50
11/21/25	6060082	JONI WILBURN	$53.20
11/21/25	6060083	TINA BYRLEY-NORRIS	$33.60
11/21/25	6060084	LYNH DICKEN	$78.40
11/21/25	6060085	JACKELINE MORALES	$26.60
11/21/25	6060086	JAMIE CONTRERAS	$116.20
11/21/25	6060087	RACHELLE POWELL	$72.81
11/21/25	6060088	GARRISON MARR	$811.85
11/21/25	6060089	MONICA SAMUELS	$35.00
11/21/25	6060090	LISA PORTER	$124.60
11/21/25	6060091	CODY BROULLETT	$686.60

Accounts Payable ACH			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/21/25	6060092	AUSTIN GRANT	$688.00
11/21/25	6060093	KIMBERLEY MULLENE	$22.40
11/21/25	6060094	SEAN O'CONNOR	$1,018.75
11/21/25	6060095	JAYME CORNELL	$1,295.00
11/21/25	6060096	FREDERICK WILLENBROCK	$60.20
11/21/25	6060097	ANTHONY HOUSE	$668.40
11/21/25	6060098	JOHN HOFFMAN	$358.60
11/21/25	6060099	JENNIFER HARRINGTON	$165.20
11/21/25	6060100	SOPHIA HITSKY	$1,504.96
11/21/25	6060101	BRENDON TURNER	$175.00
11/21/25	6060102	ELLYCE BROWER	$65.60
11/21/25	6060103	JULIETA ALTAMIRANO-CROSBY	$102.83
11/21/25	6060104	JESSICA OTIS	$11.20
		Total:	**$5,300,476.74**

Accounts Payable Wires			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/10/25	7003809	US BANK NA	$2,898,724.73
11/14/25	7003810	ICMA-RC	$113,875.00
11/17/25	7003811	CRAWFORD & COMPANY	$2,394.50
11/18/25	7003812	US DEPARTMENT OF ENERGY	$910,307.90
11/20/25	7003813	CITY OF SEATTLE	$312,408.44
11/20/25	7003814	HAMPTON LUMBER MILLS-WA INC	$69,846.89
11/20/25	7003815	ICMA-RC	$286,781.29
11/20/25	7003816	PUBLIC UTILITY DIST NO 1 OF SNOHOMI	$23,580.63
11/20/25	7003817	WHEAT FIELD WIND POWER PROJECT LLC	$1,346,596.92
11/20/25	7003818	ICMA-RC	$760,878.56
11/20/25	7003819	AVANGRID POWER HOLDINGS INC	$586,665.15
		Total:	**$7,312,060.01**

Payroll			
Period End Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/19/25	5300001408	PUD EMPLOYEES - DIRECT DEPOSIT	$5,465,895.96
11/21/25	845596 - 845602	PUD EMPLOYEES - WARRANTS	$19,275.98

Automatic Debit Payments			
Payment Date	**Payment Ref Nbr**	**Payee**	**Amount**
11/13/25	5300001405	STATE OF WA DEPT OF RETIR	$1,861,639.44
11/14/25	5300001406	WELLNESS BY WISHLIST INC	$9,152.68
11/14/25	5300001407	LIBERTY MUTUAL GROUP DBA	$51,836.32
11/20/25	5300001409	ADP INC	$1,447,206.58
11/21/25	5300001410	WELLNESS BY WISHLIST INC	$10,649.27
11/21/25	5300001411	US POSTAL SVC	$110,000.00
11/21/25	5300001412	WELLNESS BY WISHLIST INC	$17,351.49
11/21/25	5300001414	LIBERTY MUTUAL GROUP DBA	$6,743.26
		Total:	**$3,514,579.04**

BUSINESS OF THE COMMISSION

Meeting Date: December 2, 2025 **Agenda Item:** 4

TITLE

CEO/General Manager's Briefing and Study Session

SUBMITTED FOR: Briefing and Study Session

CEO/General Manager	John Haarlow	8473
Department	*Contact*	*Extension*

Date of Previous Briefing: _____

Estimated Expenditure: _____ Presentation Planned ☐

ACTION REQUIRED:

☒ Decision Preparation
- ☐ Policy Discussion
- ☐ Policy Decision
- ☐ Statutory

☐ Incidental (Information)

☐ Monitoring Report

SUMMARY STATEMENT:

Identify the relevant Board policies and impacts:

Executive Limitations, EL-9, Communications and Support to the Board – the CEO/General Manager shall…marshal for the board as many…points of view, issues and options as needed for fully informed Board choices.

List Attachments:

CEO/General Manager's Briefing and Study Session attachments

SNOHOMISH PUD
Energizing Life In Our Communities

Purchase of Property for Future 115kV Ring Bus

Maureen Barnes, Manager Real Estate Services

December 2, 2025

Purchase of Property for Future 115kV Ring Bus

- The purpose of this presentation is to:
  - ➢ Inform the Board of the proposed fee purchase of 3.06-acres located at State Route 9 SE and 184th Street SE, Snohomish (adjacent to the Clearview Substation).
  - ➢ Outline the primary terms of the transaction.
- This transaction will be before the Commission for approval by resolution at the December 16, 2025, Commission meeting.

Property Purchase, Background

- The District's Electric System Capital Plan has long identified the need for a 115kV ring bus in the Maltby/Clearview area.
- Substation Engineering and Real Estate began looking for property in 2016.
- In 2024 a site was approved to purchase via Resolution 6165, this site consisted of 10-acres and a house located at 8520 180th Street SE, Snohomish.
- The purchase price of the property was $1.95 million.
- Staff was aware of constraints on the original property such as wetlands, residential zoning with the need for a conditional use permit and demolition of the single-family house.

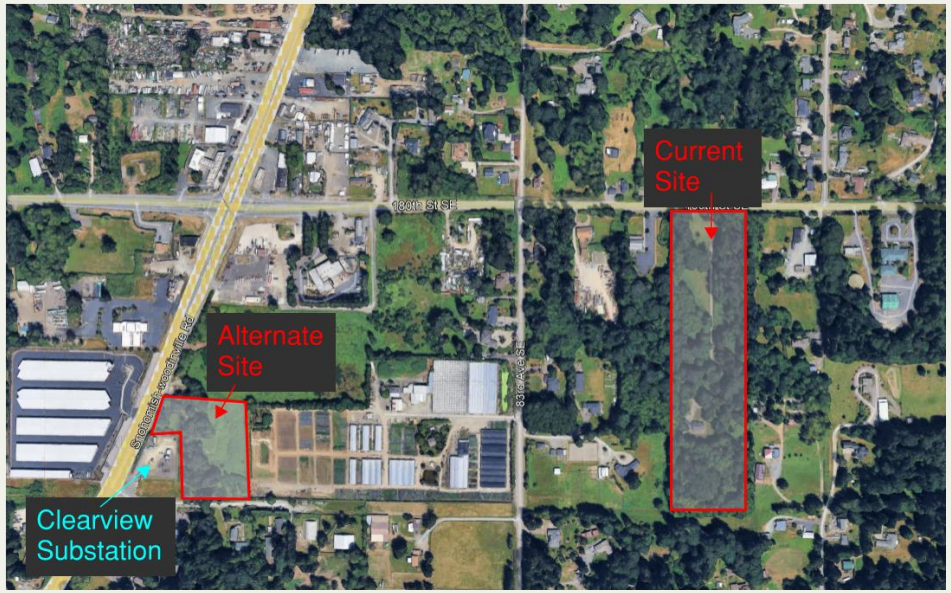
Property Purchase, Background

- While still in the planning and permitting phase an alternate parcel was listed for sale which showed advantages listed below:

Advantages
- This option offers greatly improved site layout and transmission design over the existing site - The critically important 2028 energization deadline for Paradise can still be met - Less impact to neighbor's vs current the property - Streamlined substation permitting - Decreased risk associated with permitting a substation site - Increased physical visibility of the site - This purchase reduces the amount of transmission line construction by approximately one mile - The new site provides improved reliability for Clearview substation

New Site Attributes

- Whereas the new site is smaller at 3+/- acres almost all of the property is useable, with the exception of the gas pipeline which runs along 184th St. SE.
- Zoning is favorable - Clearwater Rural Commercial (CRC) with no conditional permit required.
- Clearview Substation would be incorporated into the site design, increasing reliability and decreasing outages.
- Closer proximity to Highway 9 for future maintenance and equipment delivery.
- Approximate savings in development of approximately $1 million.
- Decrease in environmental impacts due to demolition, tree removal and just under a mile in transmission being built.


Current Site
Alternate Site
Clearview Substation


State Route 9 SE
Gas Pipeline
184th St SE



Proposed Site Due Diligence

- The following studies have been completed with no adverse results:
  - Phase I Environmental Investigations.
  - Geotechnical Investigation.
  - Cultural Resource Investigation.
  - Wetlands Report.
  - Land Survey and Title Report.
  - Member of Appraisal Institute (MAI) designated appraiser has completed an appraisal which supports the purchase price of $2.1 million.

Proposed Site Purchase

- A Business Case for the alternate site purchase was completed in August 2025 and presented to the Executive Leadership Team (ELT) they agree with the purchase.
- A Purchase and Sale Agreement (PSA) was signed in October 2025 with a purchase price of $2.1 million and closing to be completed by January 30, 2026.
- Due to the completion of the due diligence and the preference to close in 2025, due to budget constraints, we are moving forward with closing prior to December 31, 2025.

Next Steps

- On December 16, 2025, staff will return to Commission to request approval of this transaction via Resolution.
- This purchase is supported by the ELT, management and staff.
- Additionally, we plan to return to Commission in 2026 to request the original site, located at 8520 180th St. SE, be considered surplus to the District and allow for the subsequent sale.

Questions



SNOHOMISH PUD

Energizing Life In Our Communities

Connect Up Program

Commission Quarterly Update
December 2, 2025

Tim Epp, Program Director

Last Update: September 23, 2025

Connect Up Program Quarterly Update

- Purpose of Presentation: Progress update of the Connect Up Program

- Expectation of the Board: Informational Only

Topics

1. Overall Program Status
2. Meter Deployment Status
3. Advanced Metering Infrastructure (AMI) Network Status
4. AMI Operations & SnoSmart Support
5. Q&A

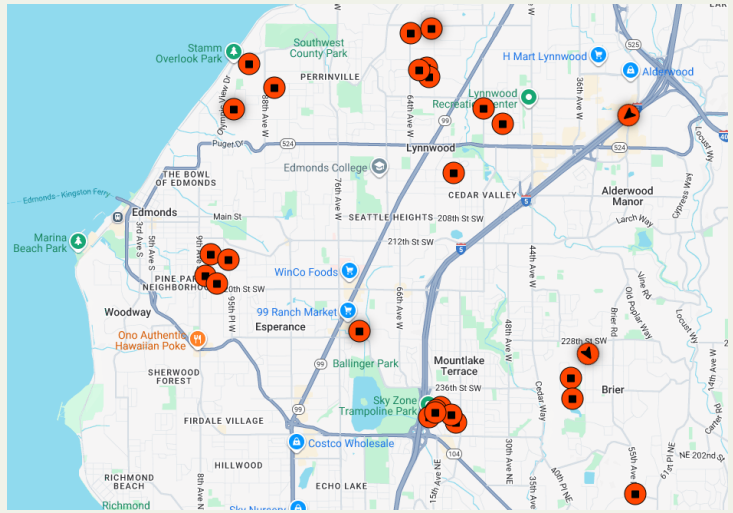
Overall Program Status

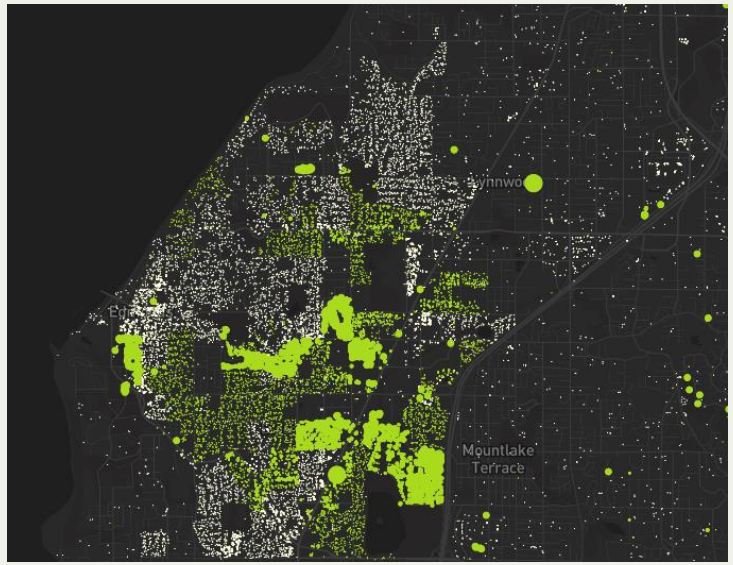


- Cost Status/Projection: Under budget
  - Projected = $92M ($68M spent through October 30, 2025)
  - Original Budget = $93.2M
- Top Risks/Issues
  - Repair Costs
  - Weather delays

Meter Deployment Status

- Electric = 140k installed (~37% of total)
  - Rate = 4,000 per week (Target = 4,000 per week)
  - Projected deployment completion = 4Q 2026
  - Program closure activities = 1H 2027
- Water = 22k installed (~92% of total)
  - Rate = 200-400 per week (Target = 250 per week)
  - Projected completion = 1Q 2026
- Opt Out rate = 0.37% (0.5% planned)
  - Slight uptick since Electric deployment moved into SW County
  - 85% of Opt Out Customers choose Self-Read option
- Deployment focus area: Woodway, Edmonds, Lynnwood



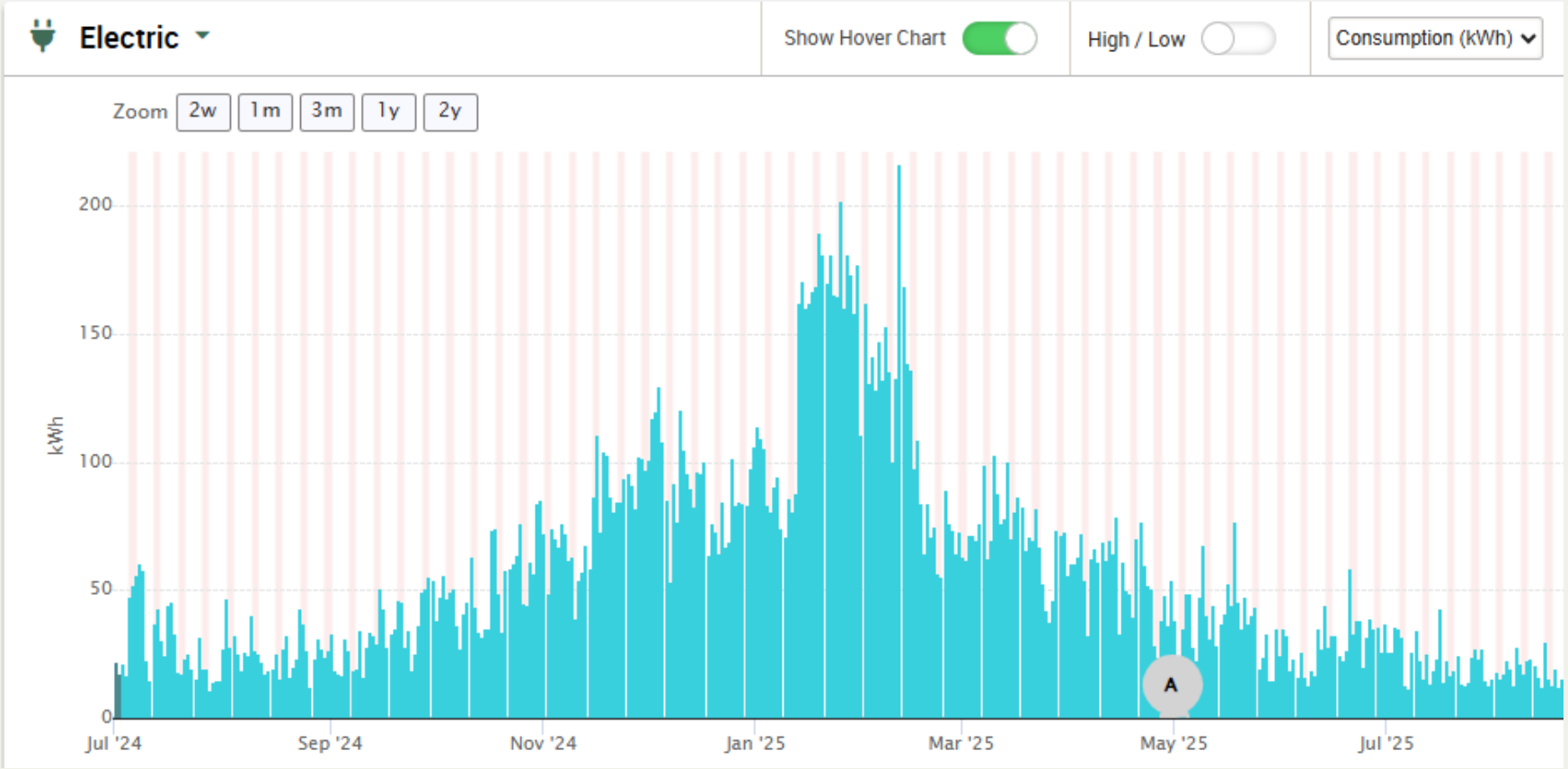


Advanced Metering Infrastructure (AMI) Network Status



- Last base station installation complete
- Woodway site installed
- Final station certifications by Sensus expected in January 2026
- Project closeout activities in February

AMI Operations & SnoSMART Support



System Performance:

- Billing consistently solid
- Alerts/Alarms
- Daylight savings bug

Vendor Performance:

- Sensus
- TRC Engineering

SnoSMART Support:

- Sensus FlexNet is network for SnoSMART (Distribution Automation Devices)

Questions?



SNOHOMISH PUD

Energizing Life In Our Communities

AUDIT ACTIVITY UPDATE

DECEMBER 2, 2025

Presented by: Shawn Hunstock, Senior Manager, Controller & Auditor
Tyler Wells, Manager, Accounting

AUDIT SUMMARY

AUDIT	PROGRESS	AUDITORS	DESCRIPTION/RESULTS	COMMENTS
2024 PUD Financial Statements	Complete	Moss Adams	Verification of financial reporting	Unqualified opinion no exceptions noted
2024 PUD Federal Single Audit	Complete	Moss Adams	Verification of eligible costs and proper expenditures	Unqualified opinion no exceptions noted
2025 PUD Financial Statements	In Progress	Moss Adams / Baker Tilly	Verification of financial reporting	2025 Interim audit work performed the week of November 17, 2025
2024 VEBA Financial Statements	Complete	Moss Adams	Verification of eligibility, proper claims payment and audit of financial statements	Unqualified opinion no audit comments

AUDIT SUMMARY

AUDIT	PROGRESS	AUDITORS	DESCRIPTION/RESULTS	COMMENTS
State of Washington 2024 Accountability Audit	In Progress	State Auditor's Office	Verification of compliance with State laws and internal policies	Audit work in progress
State of Washington 2024 CPA Financial Audit Review	In Progress	State Auditor's Office	Verification of Financial Statement audit work performed by Baker Tilly	Audit work in progress
State of Washington 2024 CPA Single Audit Review	In Progress	State Auditor's Office	Verification of Federal Audit work performed by Baker Tilly	Audit work in progress
CETA – GHG Content Calculation	Complete	State Auditor's Office	Greenhouse Gas Content Calculation for 2022	No exceptions noted

AUDIT SUMMARY

AUDIT	PROGRESS	AUDITORS	DESCRIPTION/RESULTS	COMMENTS
CETA – Energy Assistance to Low-Income Households	Complete	State Auditor's Office	Energy Assistance to Low-Income Households for 2022 and 2023	No exceptions noted
EIA – Energy Conservation Target	Complete	State Auditor's Office	Testing for Energy Conservation Target for 2022 and 2023	No exceptions noted
EIA – Renewable Energy Compliance	Complete	State Auditor's Office	Renewable Energy Compliance for 2024	No exceptions noted
EIA – Energy Conservation Acquisition	Complete	State Auditor's Office	Energy Conservation Acquisition Testing for 2022 and 2023	No exceptions noted

UPCOMING AUDITS

AUDIT	PROGRESS	AUDITORS	DESCRIPTION/RESULTS	COMMENTS
EIA – Energy Conservation Acquisition	TBD	State Auditor's Office	Energy Conservation Acquisition Testing for 2024 and 2025	To be Scheduled in 2026
EIA – Renewable Energy Compliance	TBD	State Auditor's Office	Renewable Energy Compliance for 2025	To be Scheduled in 2026
EIA – Energy Conservation Target	TBD	State Auditor's Office	Interim Testing for Energy Conservation Target for 2026 and 2027	To be Scheduled in 2026

(THE ABOVE AUDITS ARE IN ADDITION TO THE 2025 FINANCIAL STATEMENT AUDIT, FEDERAL SINGLE AUDIT, AND ACCOUNTABILITY AUDIT)

UPCOMING AUDITS

AUDIT	PROGRESS	AUDITORS	DESCRIPTION/RESULTS	COMMENTS
CETA – Energy Assistance to Low-Income Households	TBD	State Auditor's Office	Energy Assistance to Low-Income Households for 2024 and 2025	To be Scheduled in 2027
CETA – Clean Energy Implementation Plan – Interim Reporting	TBD	State Auditor's Office	Interim Reporting for Clean Energy Implementation Plan for 2022 - 2025	To be Scheduled in 2027
CETA – Clean Energy Implementation Plan	TBD	State Auditor's Office	Clean Energy Implementation Plan for 2026 - 2029	To be Scheduled in 2027

(THE ABOVE AUDITS ARE IN ADDITION TO THE 2025 FINANCIAL STATEMENT AUDIT, FEDERAL SINGLE AUDIT, AND ACCOUNTABILITY AUDIT)

SNOHOMISH PUD
Energizing Life In Our Communities

Water Supply Update



December 2, 2025

Scott Richards, Utility Analyst

Previous Presentation: April 22, 2025

Purpose: To update the Commission on the water supply status. No action needed.

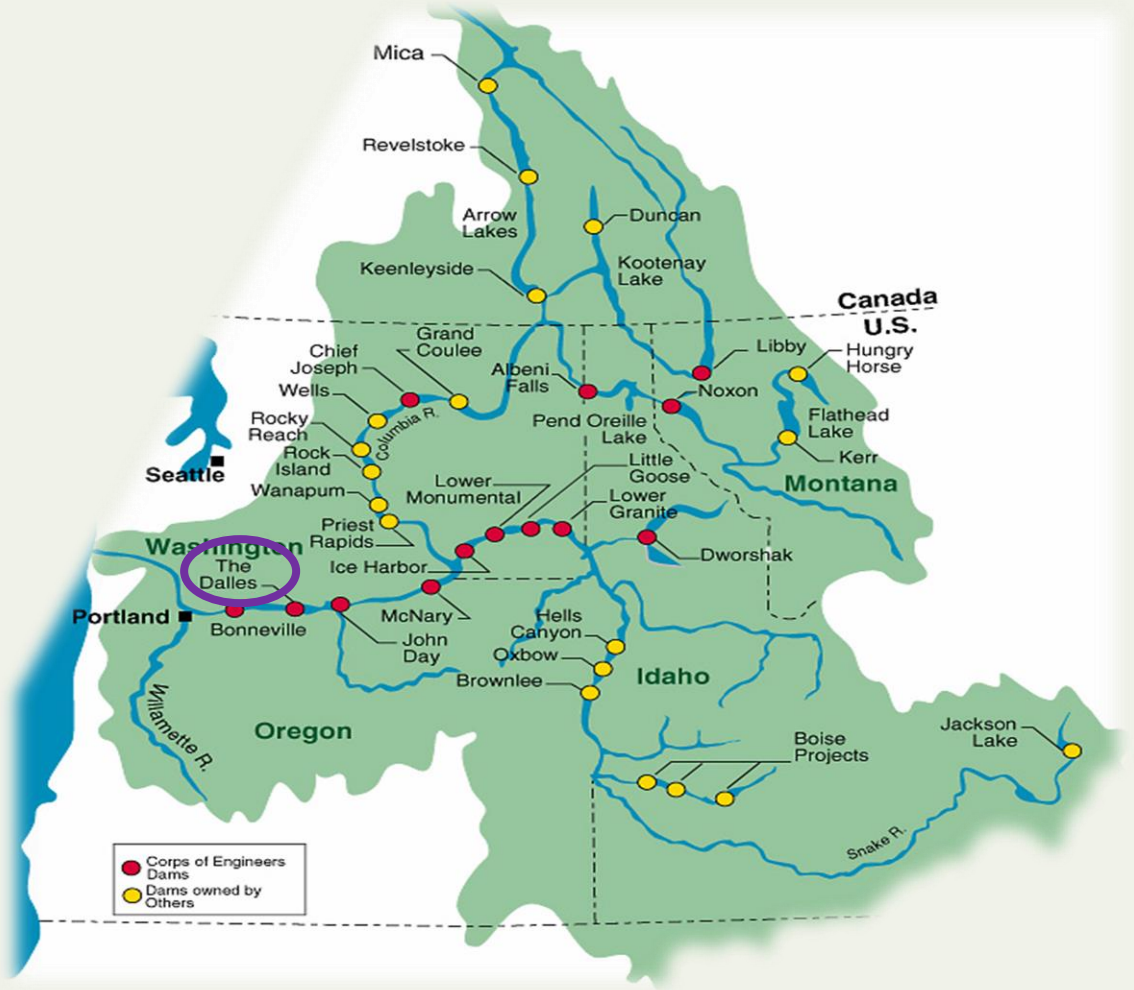
Topics:

- Columbia River Watershed
- Final 2025 Water Supply Forecast at The Dalles
- Monthly Flow Profile & Slice Generation
- District Hydro Generation for April Through October
- Slice Contract Close Out & Load Following for Hydro

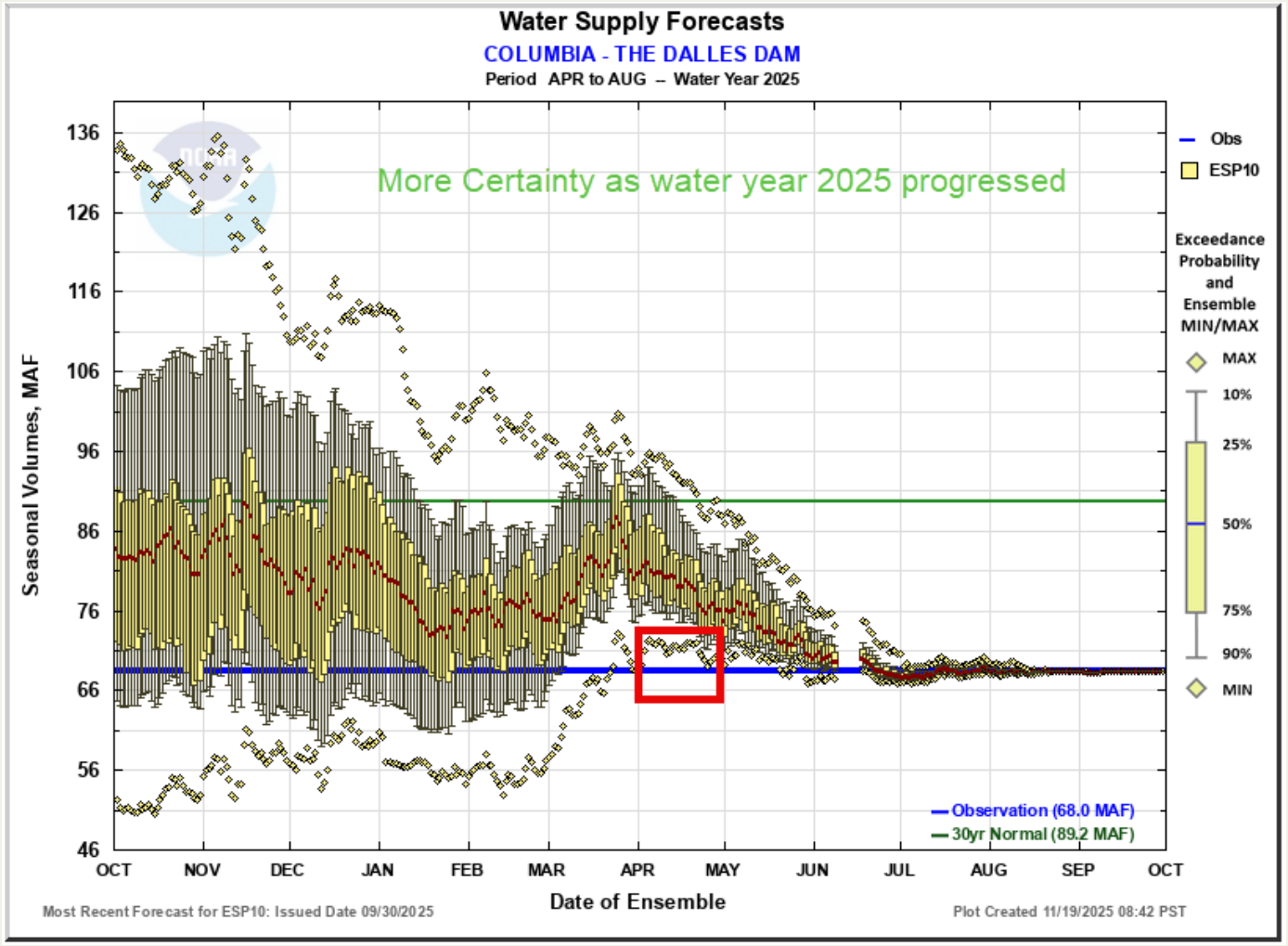
Not Covered:

- Monthly breakdowns of precipitation/temperature

Columbia River Watershed and The Dalles Dam

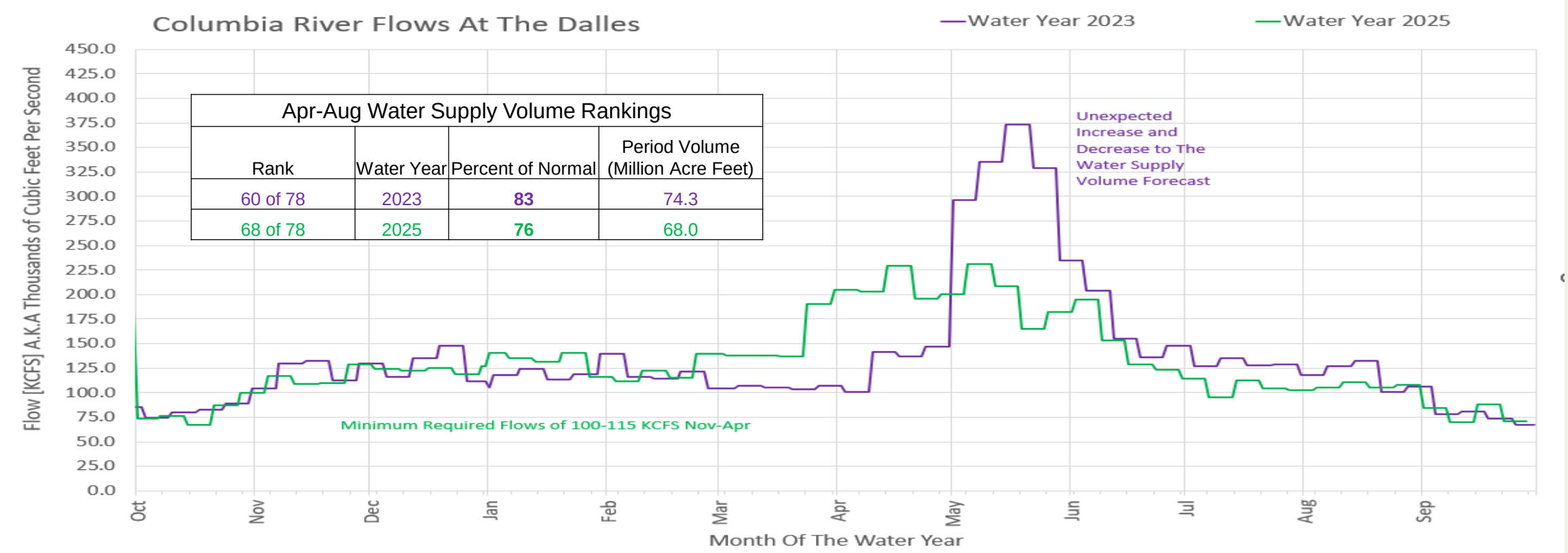


The 2025 Water Supply Forecast Ended Well Below Average



Apr-Aug Water Supply Volume Rankings			
Rank	Water Year	Percent of Normal	Period Volume (Million Acre Feet)
1	1997	149	132.9
24	2022	108	95.9
31	2020	103	92.1
~~53~~	~~2025~~	~~90~~	~~80.3~~
60	2023	83	74.3
64	2021	80	71.6
68	**2025**	**76**	**72.8**
71	2024	73	65.5
78	1973	47	42.0

Monthly Flow Profile & Slice Generation



Apr-Aug Water Supply Volume Rankings			
Rank	Water Year	Percent of Normal	Period Volume (Million Acre Feet)
60 of 78	2023	**83**	74.3
68 of 78	2025	**76**	68.0

Average Slice Generation in [MW]												
Water Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
2023	300	445	463	426	421	365	288	545	356	395	406	298
2025	298	420	450	466	410	455	413	342	356	355	389	306
							Apr- Aug Required Spill for Fish					

District Hydro Monthly Generation

2025 District Hydro Generation [MW]									
	Storage		Apr	May	Jun	Jul	Aug	Sep	Oct
Youngs Creek	No	**Actual**	**3**	**2**	**0**	**0**	**0**	**0**	**0**
		Typical	3	2	1	0	0	2	3
Calligan	No	**Actual**	**3**	**0**	**0**	**0**	**0**	**0**	**0**
		Typical	5	5	4	1	0	1	2
Hancock	No	**Actual**	**4**	**3**	**0**	**0**	**0**	**0**	**1**
		Typical	4	6	4	0	0	2	2
Jackson	Yes	**Actual**	**56**	**16**	**20**	**24**	**25**	**23**	**29**
		Typical	47	53	51	32	27	28	36

Conservation of Spada Lake Through October



2025 District Hydro Generation [MW]								
		Apr	May	Jun	Jul	Aug	Sep	Oct
Jackson	Actual	56	16	20	24	25	23	29
	Approximated Minimum*	**~20**	~16	~20	~24	~25	~23	**~18**

Slice Contract Closeout & The Future For District Hydro

- SNOPUD's Slice simulation was brought into this world in October of 2012, lived for nearly 13 water years and went peacefully in September of 2025.
- Survived by the following District Owned Hydro resources: Jackson, Young's Creek, Calligan & Hancock.
- The Slice contract closeout resulted in **9188 MWh** worth of energy being owed to the District. This generated a ~$0.5M credit.
- Jackson & Youngs Creek generation under Load Following will be valued against monthly prices, set by BPA, months in advance.
- The output of Calligan & Hancock was sold at a fixed, annual prices.

Residual Questions?

Proposed updated cadence for future Water Supply updates:

- Annually, every April (I.E. April of 2026 & April of 2027).

SNOHOMISH PUD

Energizing Life In Our Communities

Energy Risk Management Report

Q2 2025 – Q3 2025

December 2, 2025

Peter Dauenhauer, Senior Manager Rates Economics & Energy Risk Management

Felicienne Ng, Principal Economist

» **Last Presentation**: April 22, 2025

This Presentation

- Purpose of this Presentation:
  - Report on the Energy Risk considerations and actions of the Energy Risk Management Committee (ERMC) over the last 6-months.
  - Discuss Future Energy Risk Directions.
- Expectations of the Board:
  - Informational Only.

Recent Meetings

- 2025-04-22 – Q4’24-Q1’25 Bi-Annual Risk Report
- 2024-10-22 – Q2’24-Q3’24 Bi-Annual Risk Report
- 2024-04-16 – Q4’23-Q1’24 Bi-Annual Risk Report
- 2023-10-17 – Q2 -Q3 ‘23 Bi-Annual Risk Report
- 2023-04-13 – Q4 ‘22-Q1’23 Bi-Annual Risk Report
- 2022-10-03 – Q2-Q3 ‘22 Bi-Annual Risk Report

Agenda

- Energy Risk Background and Fundamentals
- Sources of Risk
- Q2 2025, Q3 2025 Risk In Retrospect
- Risk Program After October 1, 2025



Primary Focus of Risk Mitigation During Block + Slice

- During the Block+Slice regime, the basis of the Risk Program was to limit financial risks stemming from variable load resource balancing.
- While the PUD is no longer subject to the same profile of risks due to the product change to Load Following on 10/1/2025, the Energy Risk Management Committee (ERMC) remains dedicated to providing scheduled reports on energy risk management.

A discussion program status post-product switch is held at the end of this presentation.


Background

Background on Risk Policy

- The ERMC makes its best efforts to anticipate both the consumption of electric power by its customers and the supply of electric power available.
- The PUD engages in transactions to meet customer needs in a dependable, safe, and responsible manner.
- These transactions included buying, selling, and scheduling of electric power, options for electric power, or other energy commodities as necessary to meet load and mitigate risk.

Key Strategies

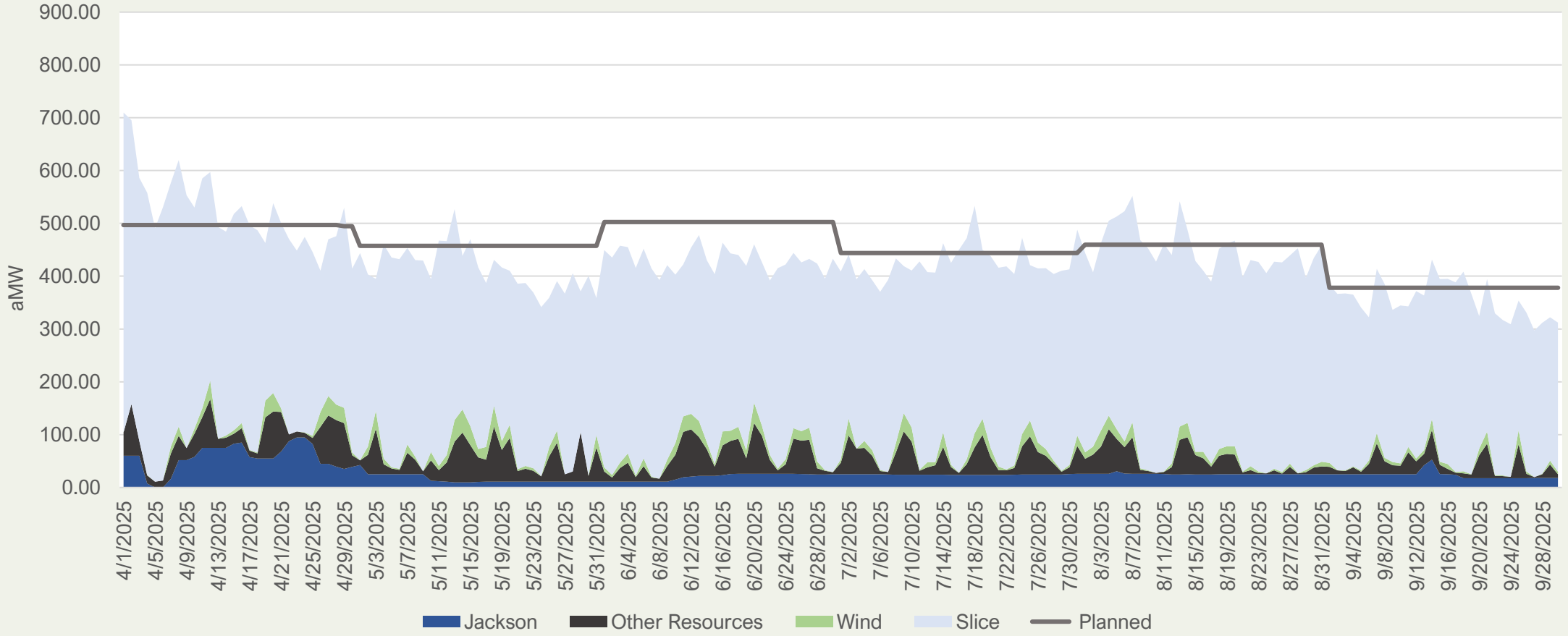
- Define and update uncertainties and risks related to:
  - Resources and Load Demand.
  - Market Prices.
- Keep monthly market position near neutral in the short-term horizon (36 months) by:
  - Keeping exposure to market prices below limits.
    - Limits are set to cap the impacts of market movements to no more than a 3% rate increase.
  - Reducing risks from within month balancing.
  - Transacting market operations over time to “average out” market variations (Glidepath).



Energy Risk in Q2 ’25 – Q3 ’25

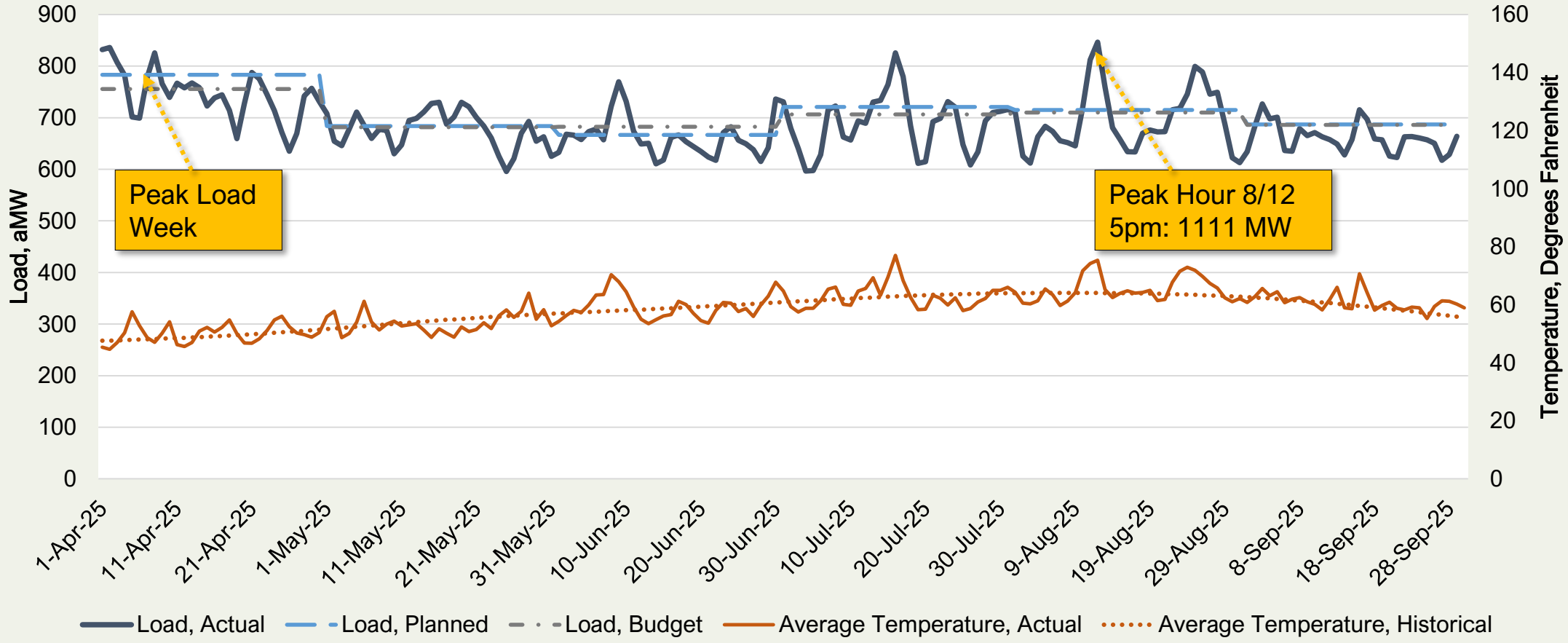
Resources (Supply)

Q2 2025 - Q3 2025	Actual Relative to Planned						
	Q2 '25 - Q3 '25	April	May	June	July	August	September
Slice	97%	107%	99%	85%	97%	101%	98%
Wind	92%	80%	112%	88%	95%	80%	75%
Jackson	80%	121%	29%	133%	94%	101%	93%
Other Resources	58%	88%	55%	27%	60%	27%	26%
TOTAL	**94%**	**105%**	**91%**	**86%**	**96%**	**98%**	**94%**

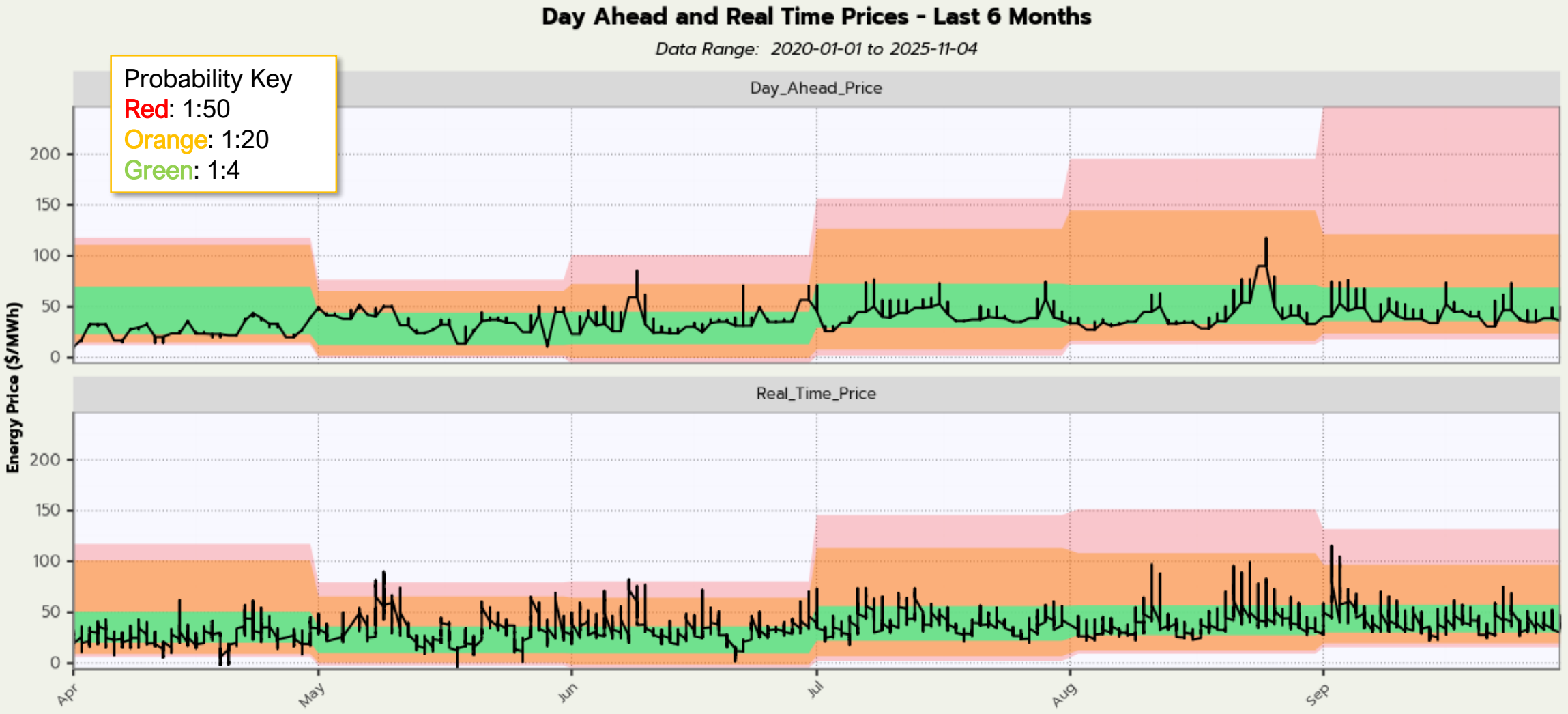


Load (Demand)

Q2 2025 - Q3 2025	Actual Relative to Planned Loads						
	Q2 '25 - Q3 '25	April	May	June	July	August	September
Budget Forecast	704	756	681	682	706	710	686
Month-Ahead Forecast	709	783	684	667	721	715	687
Actual	688	745	676	662	688	695	661
Actual vs. Budget	**98%**	**99%**	**99%**	**97%**	**97%**	**98%**	**96%**
Actual vs. Month-Ahead	**97%**	**95%**	**99%**	**99%**	**95%**	**97%**	**96%**

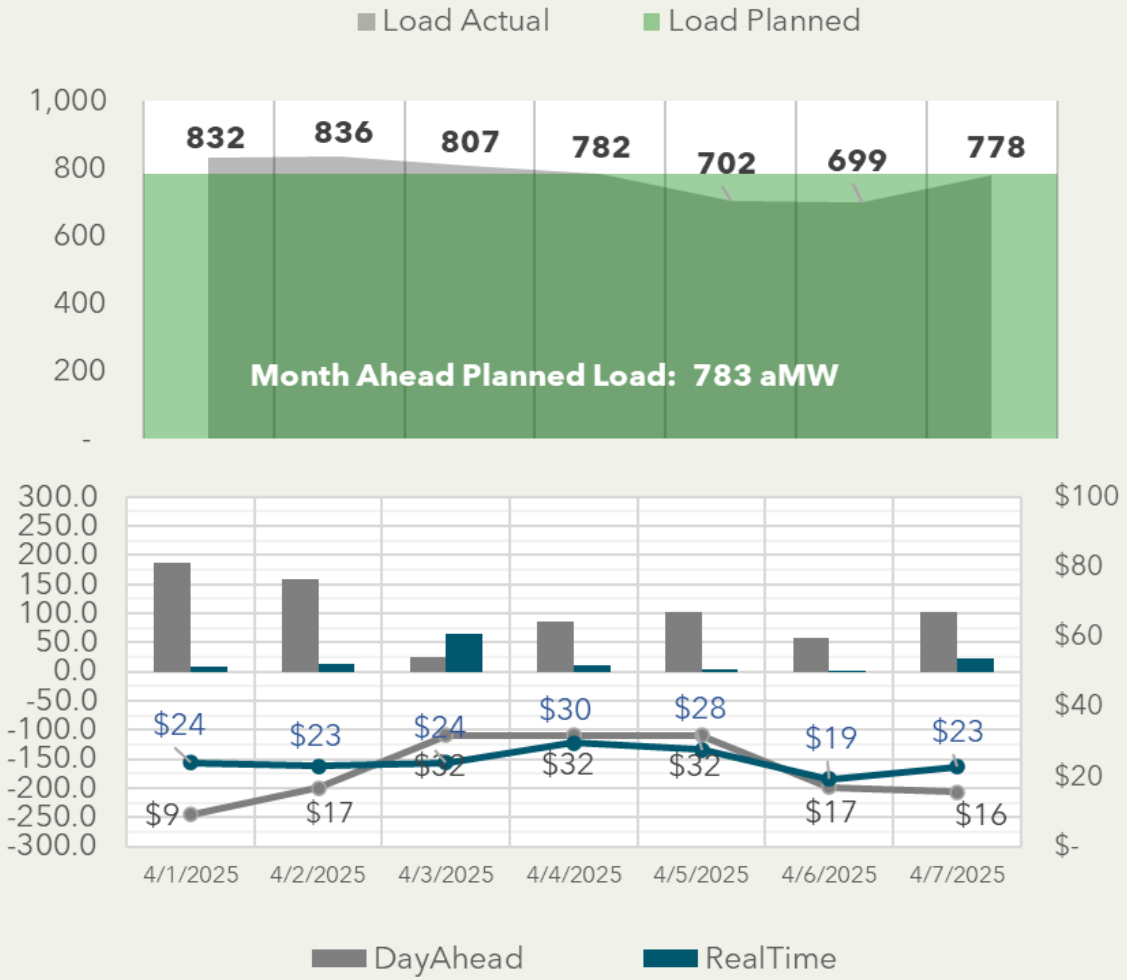


Market Prices April ‘25 – September ‘25



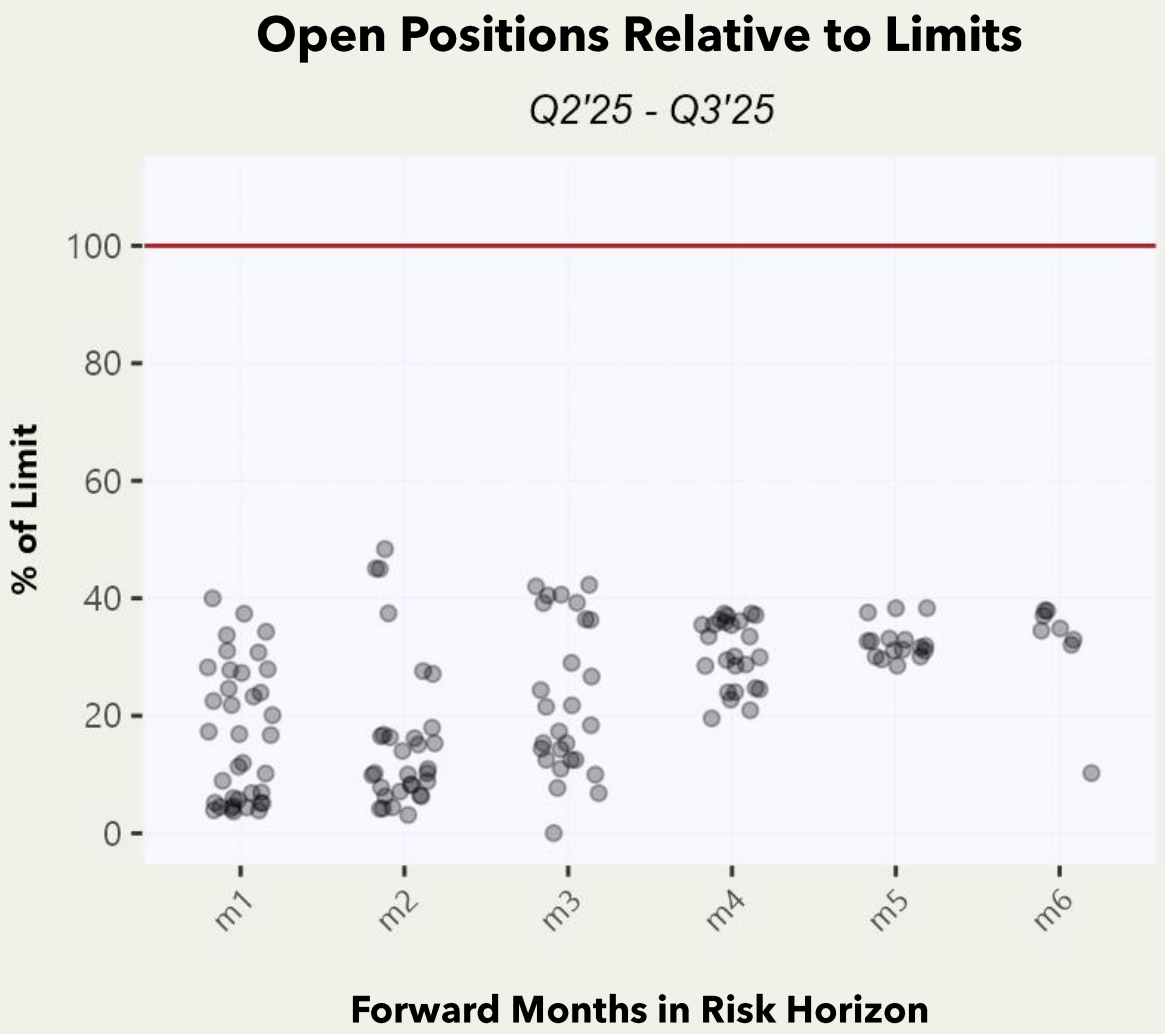
Peak Load Week

- The “Peak Load Week” during the last 6 months has the largest total load demand during a single week.
- Market prices during those periods are also shown.
- The week of April 1- 7, 2025 was our peak week over the period, with **1004 MW** at 7:00 – 8:00 a.m. on April 4, 2025.
- Prices over this week peaked at $32 Day Ahead, $30 Real-Time.



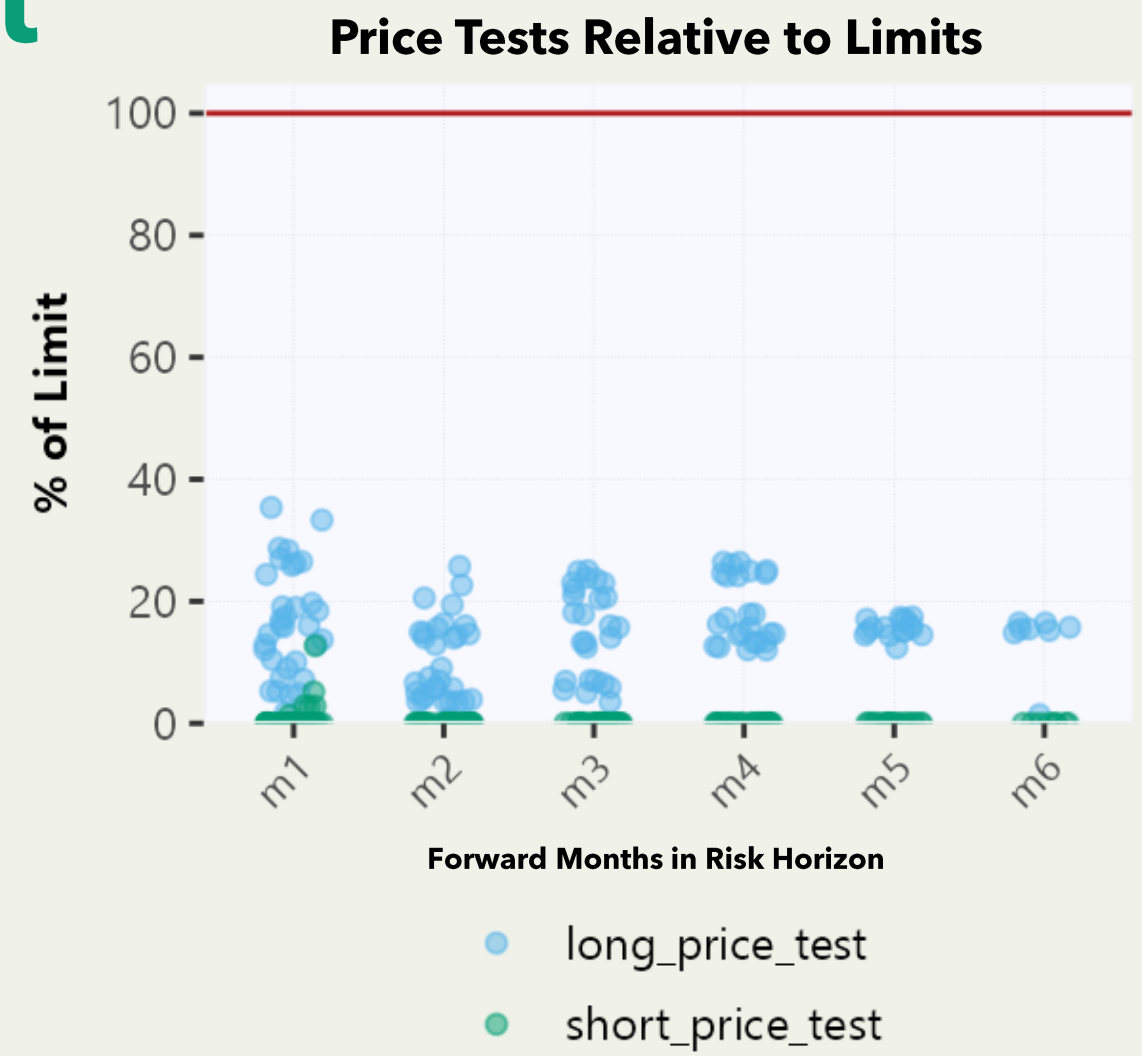
Financial Load Imbalance Test

- If resources are not equal to load, we have an “open position”. This test show whether this value is above or below limits we set. The value of these open positions is not certain.
- Each dot represents one “% of Limit” test during future months.
- There were no exceedances during the period.



Price Exposure Test

- Our net long or short positions are subject to risk through movements in market prices.
- Risk limits for this test apply for possible price movements. These are calculated from observed price volatility.
- Each dot represents one “% of Limit” test observed in the period.
- There were no price exceedances in the period.



Risk Program Development

Status and Next Steps

- The ERMC has continued to maintain compliance with its policy post-product switch.
- Given the switch to Load Following, the ERMC is now reviewing our current risk profile and will be reviewing options for transitioning the program to suit our energy risk management needs.
- This work is targeted Q3 2026 for completion.

BUSINESS OF THE COMMISSION

Meeting Date: December 2, 2025 **Agenda Item:** 5

TITLE

CEO/General Manager's Report

SUBMITTED FOR: CEO/General Manager Report

CEO/General Manager	John Haarlow	8473
Department	*Contact*	*Extension*

Date of Previous Briefing: _____

Estimated Expenditure: _____ Presentation Planned ☐

ACTION REQUIRED:

☐ Decision Preparation
☐ Policy Discussion
☐ Policy Decision
☐ Statutory

☒ Incidental (Information)

☐ Monitoring Report

SUMMARY STATEMENT:

Identify the relevant Board policies and impacts:

The CEO/General Manager will report on District related items.

List Attachments:
None

BUSINESS OF THE COMMISSION

Meeting Date: December 2, 2025 **Agenda Item:** 6A

TITLE

Public Hearing on Proposed 2025 Integrated Resource Plan

SUBMITTED FOR: Public Hearing

Power Supply	Landon Snyder	8094
Department	*Contact*	*Extension*

Date of Previous Briefing: October 21, 2025
Estimated Expenditure:
Presentation Planned ☒

ACTION REQUIRED:

☒ Decision Preparation
- ☒ Policy Discussion
- ☐ Policy Decision
- ☒ Statutory

☐ Incidental (Information)

☐ Monitoring Report

SUMMARY STATEMENT:

Identify the relevant Board policies and impacts:

Governance Process, GP-3(4)C(1) – a non-delegable, statutorily assigned duty – Rates/fees. Ends Policy 2.2 – Utilities are in adequate supply with reasonable reserves

Chapter 19.280 RCW requires utilities such as Public Utility District No. 1 of Snohomish County (the "District") to formally adopt Integrated Resource Plans ("IRPs") by September 1, 2008, to adopt and file with the Washington State Department of Commerce a comprehensive IRP every four years, and report on the progress on that plan or provide an update every two years thereafter to Commerce. The District must adopt an IRP by the end of 2025 due to this timing requirement.

In putting together the IRP, the District is required to consider and assess, among many other factors, commercially available conservation and energy efficiency resources, commercially available demand response and smart rates programs, commercially available generation and energy storage technologies, and to conduct a comparative evaluation of renewable and non-renewable resources.

The proposed 2025 IRP is a comprehensive Integrated Resource Plan spanning a 20-year planning horizon. The 2025 IRP contains the biennial conservation targets required by the Energy Independence Act, Chapter 19.285 RCW, and informs the separate Clean Energy Implementation Plan required by the Clean Energy Transformation Act, Chapter 19.405 RCW. District staff

presented to the Board of Commissioners a series of briefings throughout the IRP development, including discussion of the biennial conservation targets, and the Clean Energy Implementation Plan. A copy of the Draft 2025 IRP and Draft 2025 Clean Energy Implementation Plan was posted to the District's publicly accessible website at www.snopud.com/irp on October 13, 2025.

Staff provided a programmatic environmental checklist for the proposed 2025 IRP under the State Environmental Policy Act ("SEPA"). The District's SEPA Responsible Official issued a Determination of Non-Significance ("DNS") for the proposal on October 13, 2025, and published the DNS and the Draft 2025 IRP for the required comment period. No comments were submitted in the comment period.

The proposed final 2025 IRP contains de minimums updates to the Draft 2025 IRP but is substantively the same as the draft presented to Commission.

Board consideration of adoption of the 2025 IRP is scheduled for December 16, 2025.

List Attachments:
Presentation
Proposed 2025 IRP

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Energizing Life In Our Communities

2025 Integrated Resource Plan

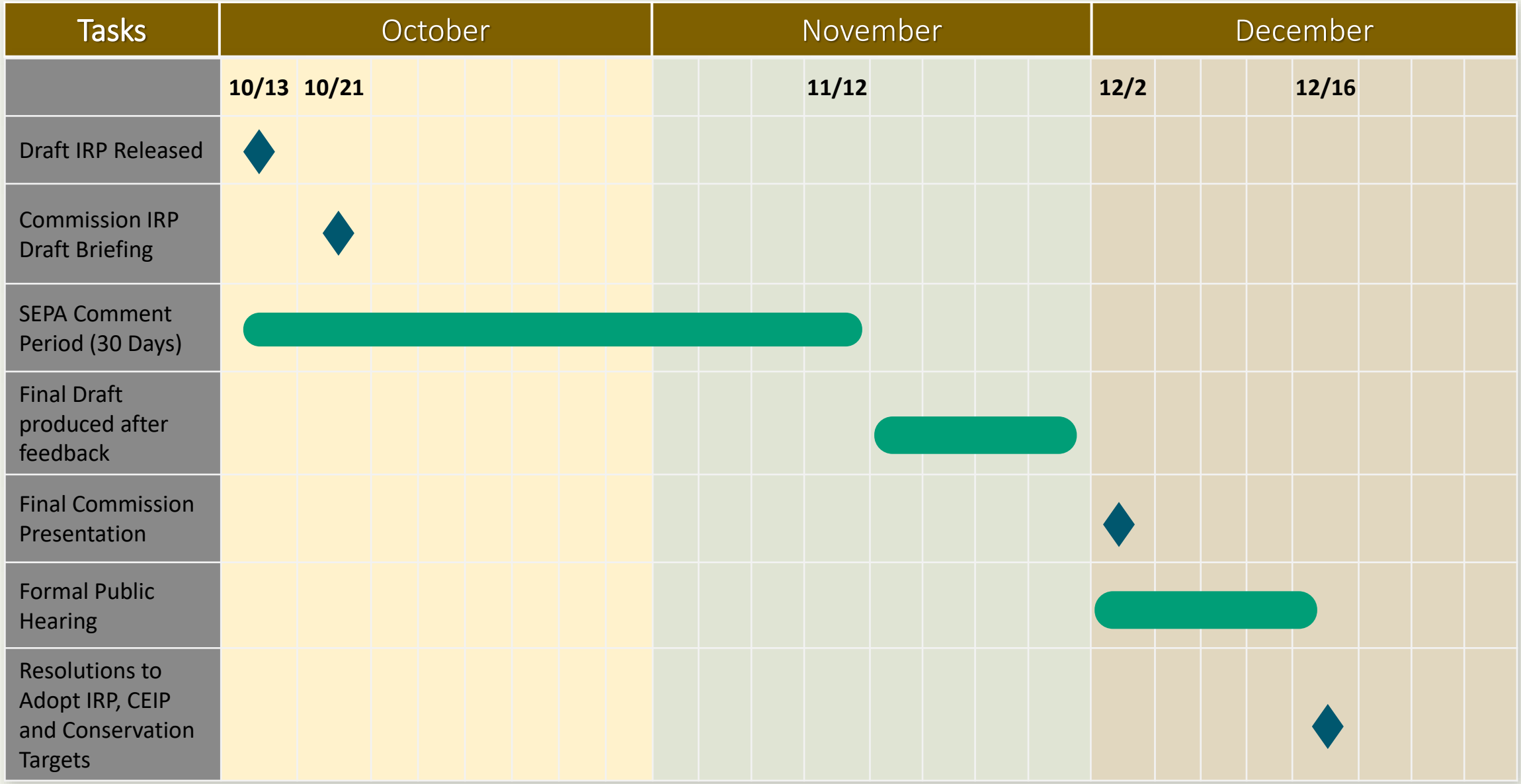
Landon Snyder – Utility Analyst
December 2, 2025
Prior Presentations – 1/21/25, 4/8/25, 6/17/25, 8/19/25, 9/23/25, 10/21/2025

Agenda

- Context
- Integrated Resource Plan (IRP) Key Findings

This public hearing briefing is intended to allow for further public comment ahead of December 16, 2025, Board consideration of a Resolution to adopt the 2025 IRP.

End of Year Timeline

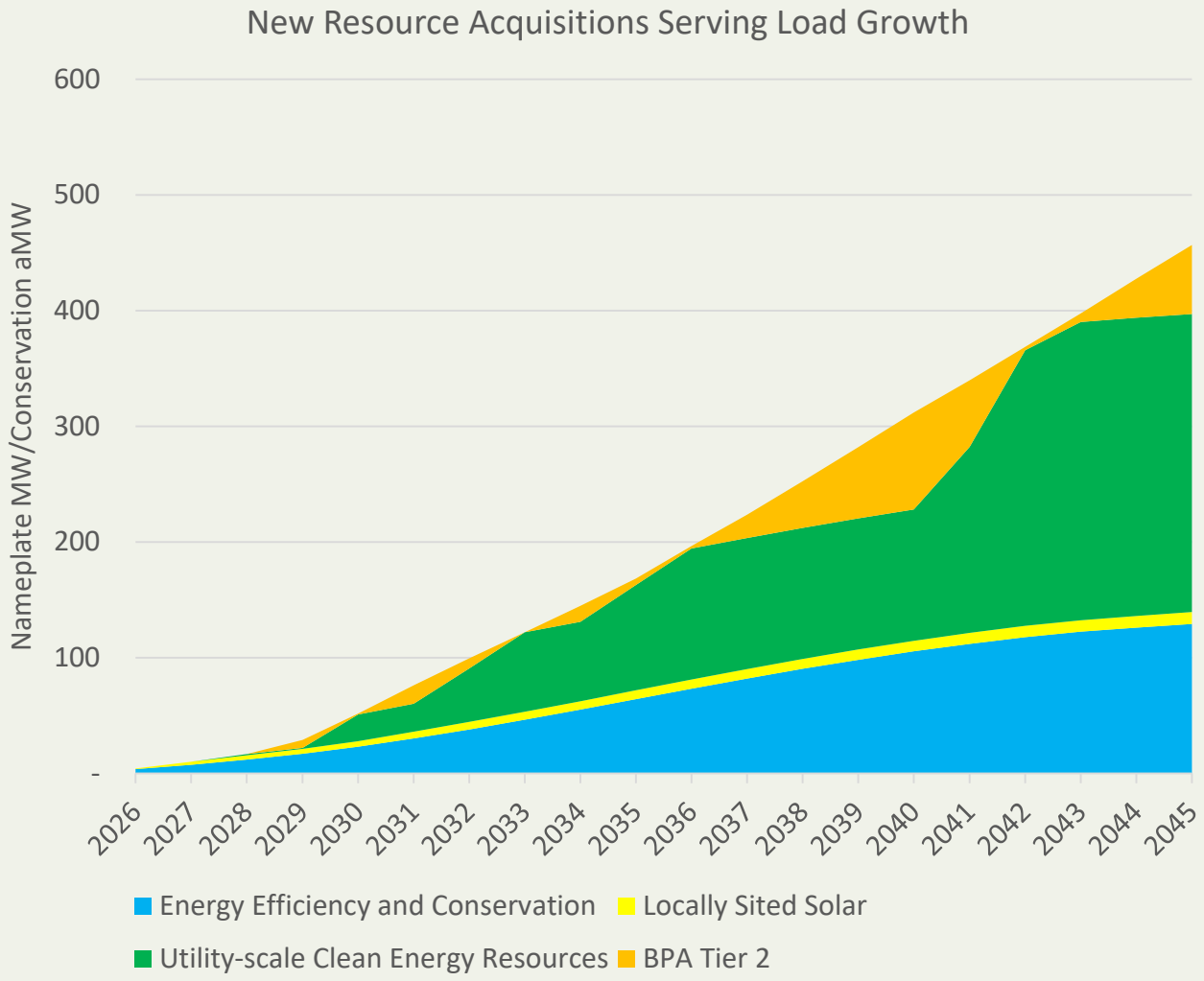


Context

- Chapter 19.280 RCW requires utilities such as Public Utility District No. 1 of Snohomish County (the "District") to formally adopt Integrated Resource Plans ("IRPs") by September 1, 2008, to adopt and file with the Washington State Department of Commerce a comprehensive IRP every four years. The District must adopt an IRP by the end of 2025 due to this timing requirement.
- Staff have presented IRP analysis in the course of multiple briefings and released the comprehensive draft 2025 IRP on October 13, 2025. Staff also completed a State Environmental Protection Act (SEPA) process including opportunity for public comment which resulted in a Determination of Non-Significance.

IRP Context

- IRP's solve for the lowest cost, lowest risk resources to serve PUD customer load. Comprehensive analysis can be found at www.snopud.com/irp.
- Conservation, Demand Response, and Renewable Resource investments are the primary resource additions that result in lowest costs:
  - These results are similar to previous IRP's.
  - Regulatory compliance considerations drive resource investments, which would be augmented by environmental attribute purchases.
- **Short-Term BPA Tier 2 Power is used as a bridge** between resource additions.
- The portfolio results in **increased portfolio diversity** over time.



SNOHOMISH COUNTY
PUD
PUBLIC UTILITY DISTRICT NO. 1







2025 Integrated Resource Plan



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
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.

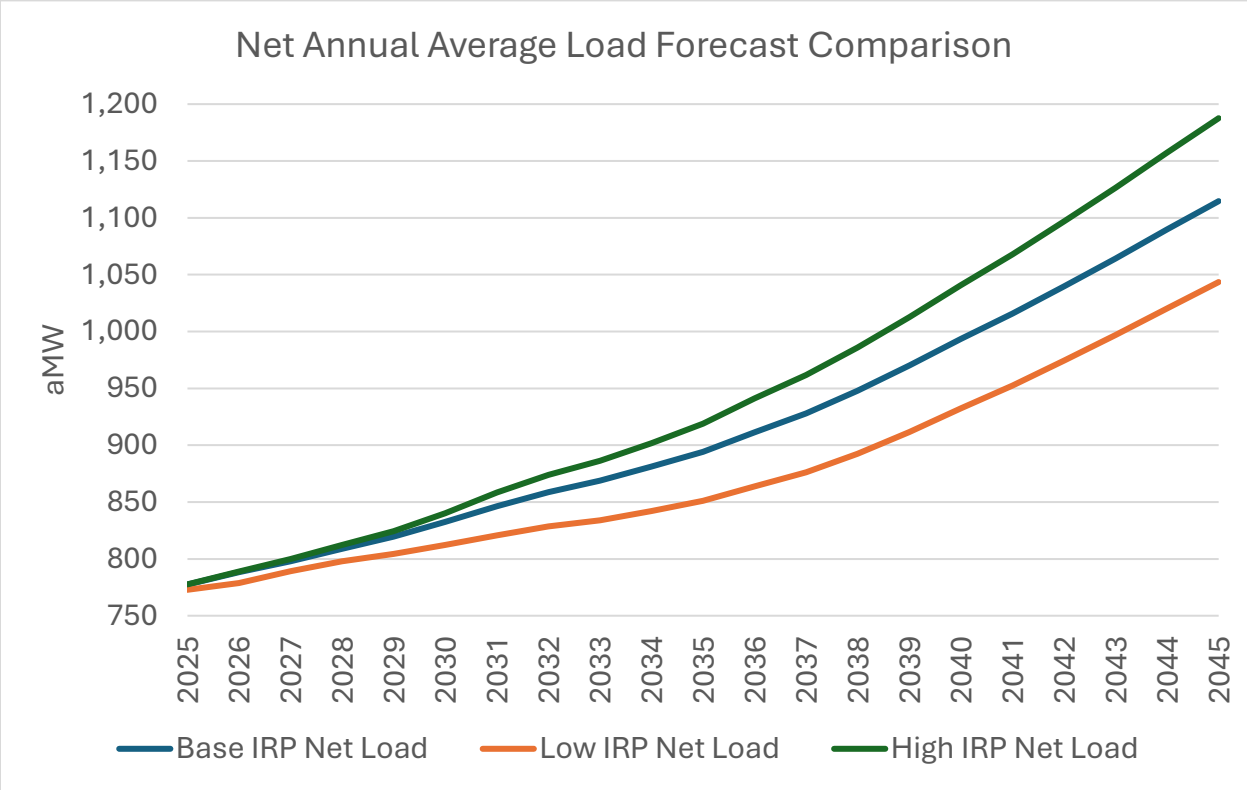
7. **Ensure continued compliance with state clean energy mandates**
    - The PUD continues to comply with the EIA, while pursuing the most cost-effective compliance pathway for PUD customers. In 2022, the PUD successfully applied the no load growth methodology for the 2021 compliance year, resulting 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

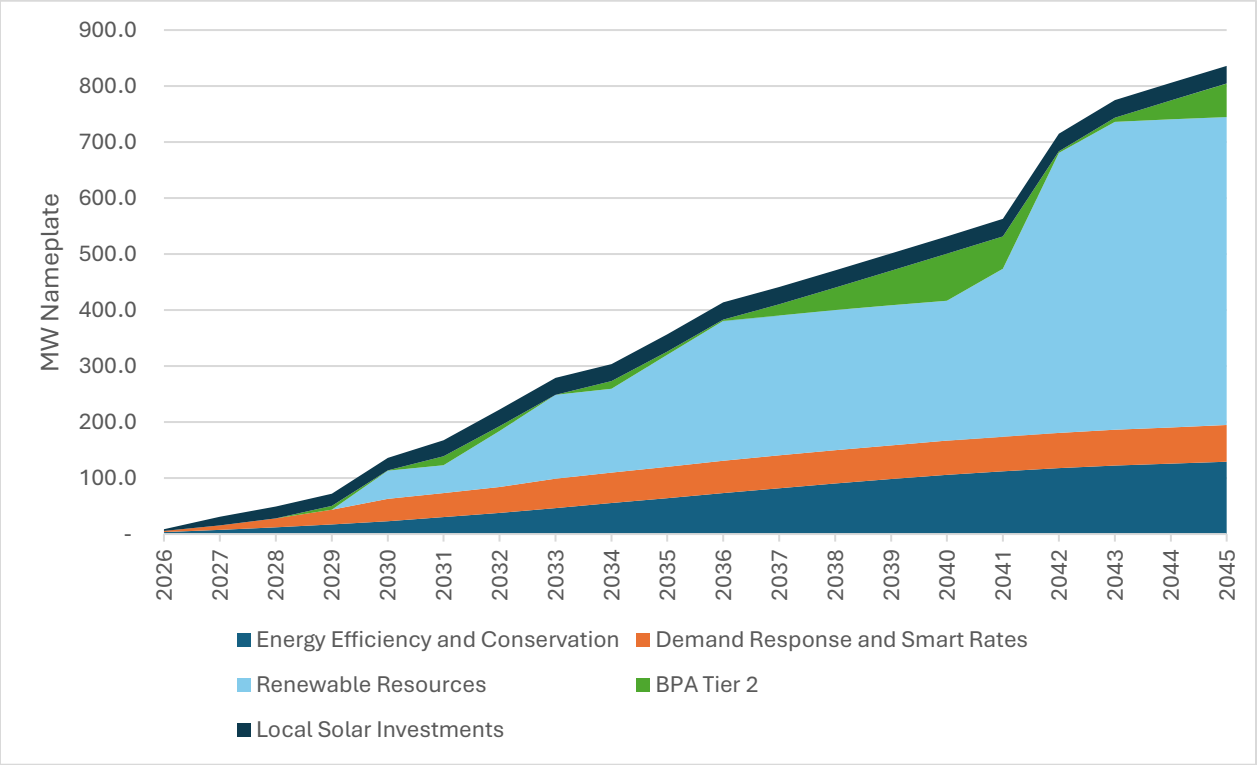
Scenario	Conservation (aMW)	DR & Rates (MW)	Local Solar (Nameplate MW)	Renewable Resources (Nameplate MW)	BPA Long-Term Tier 2 (aMW)	Battery Energy Storage (Nameplate MW)
Base	64.2	56.1	34.0	100	-	-
Low	57.5	56.1	34.0	-	-	-
High	74.9	56.1	34.0	200	-	-
High Technology	64.2	56.1	34.0	150	-	-
Limited Renewable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

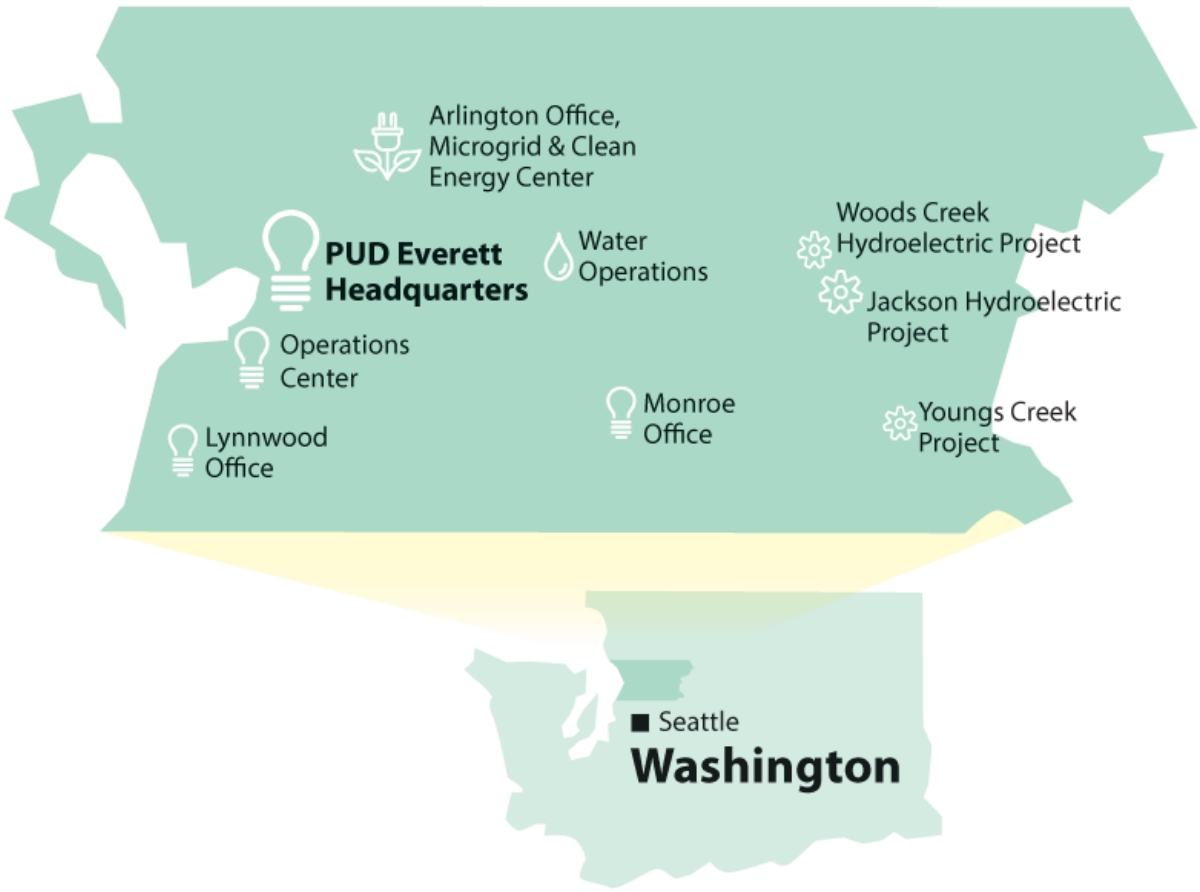
2 Who We Are

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.

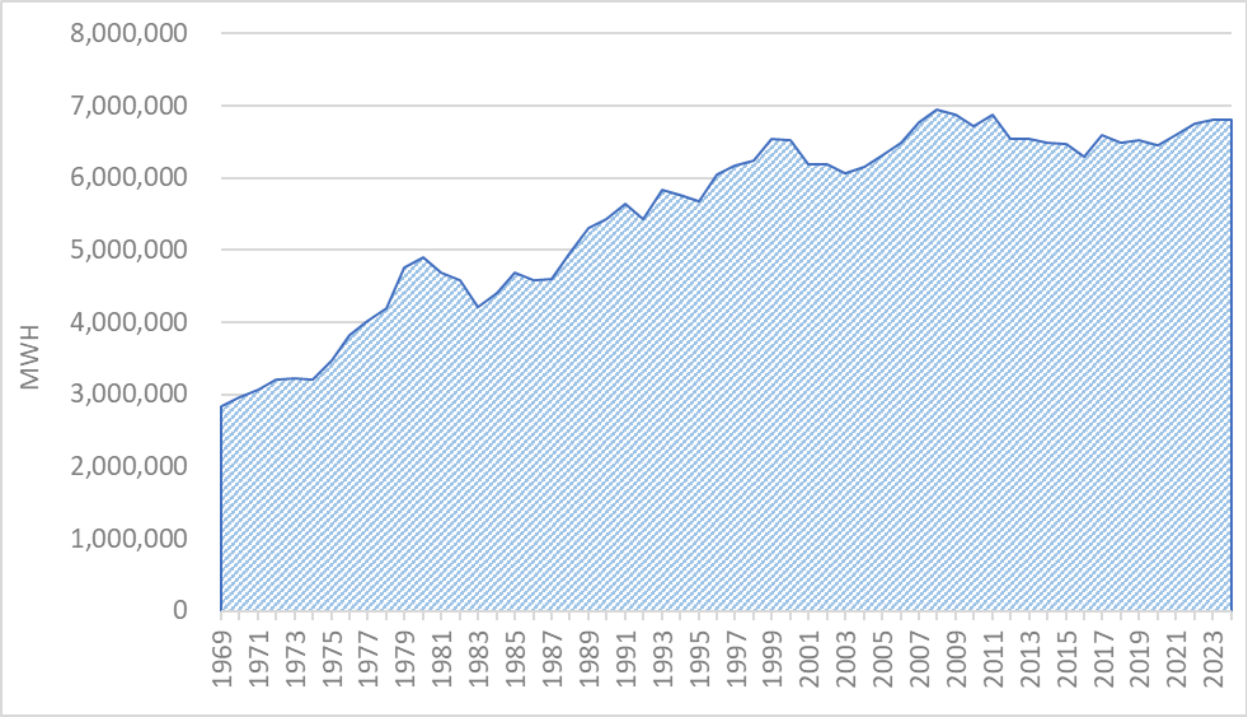
Figure 2-1 Snohomish PUD Service Territory



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.

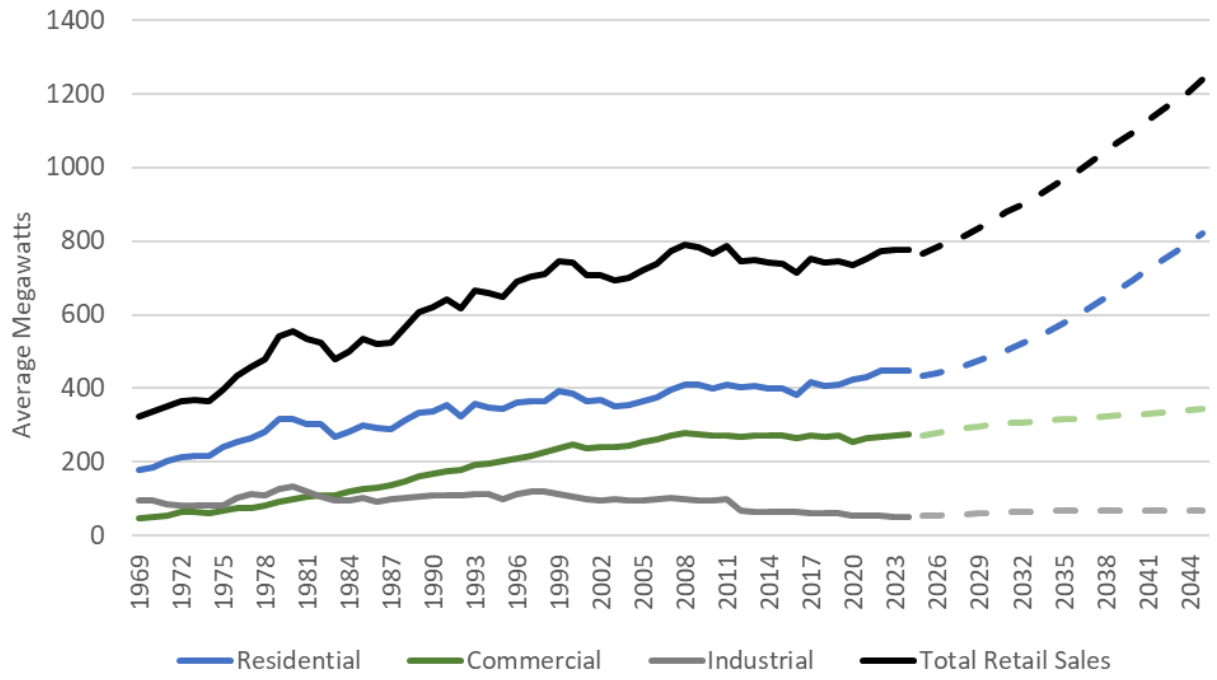
Snohomish County's main employment base remains in aerospace manufacturing, primarily Boeing's Everett Plant, and hundreds of small aerospace companies delivering parts for the 747, 767, 777, and 787 programs. Naval Station Everett, Snohomish County, and Providence Hospital are also major employers in 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.

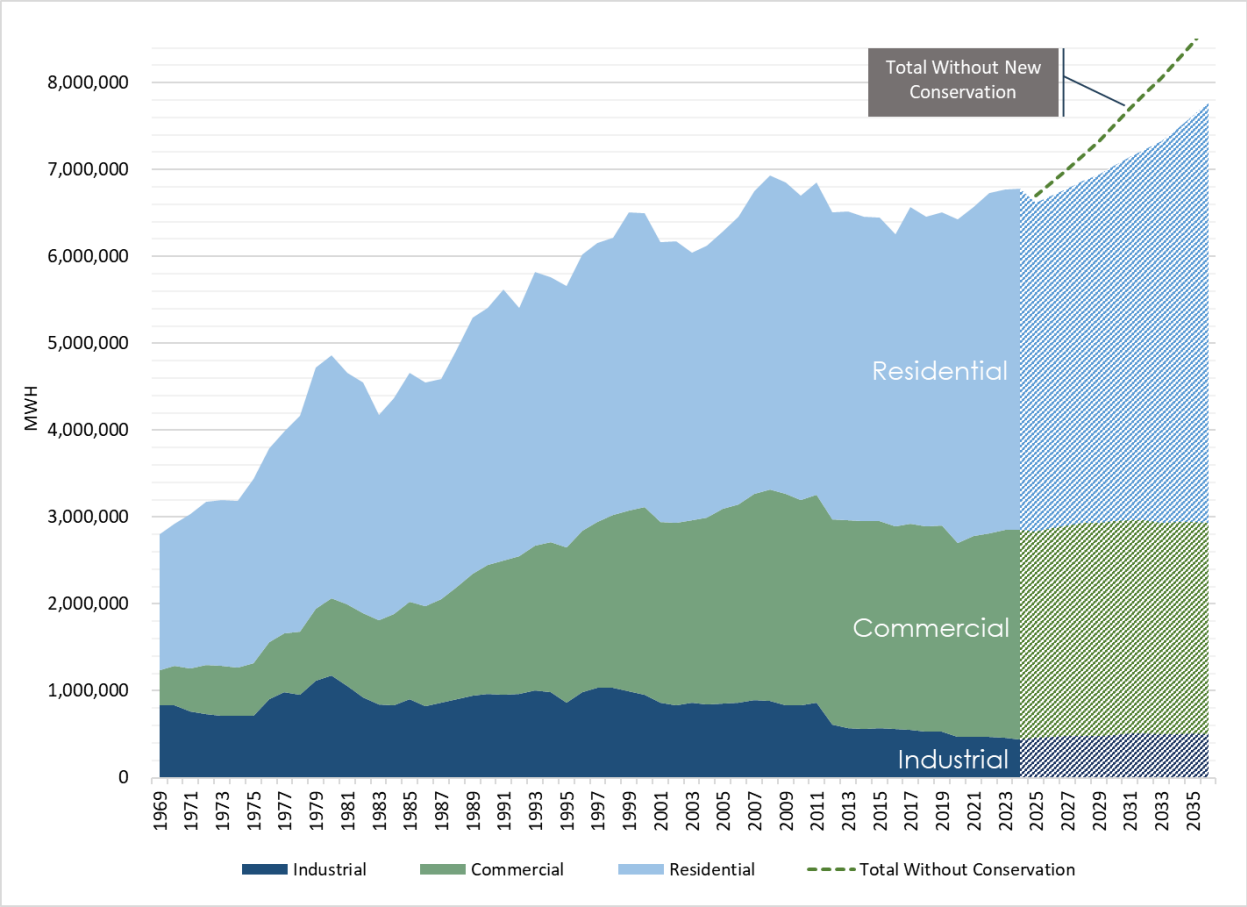
[1] Section 2 – *Who We Are*, discusses the PUD's load forecast methodology and current trends. Section 4 – *Scenarios and Planning Assumptions*, describes the various future socio-economic factors and elements considered in the study scope of 2025 IRP analysis.

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

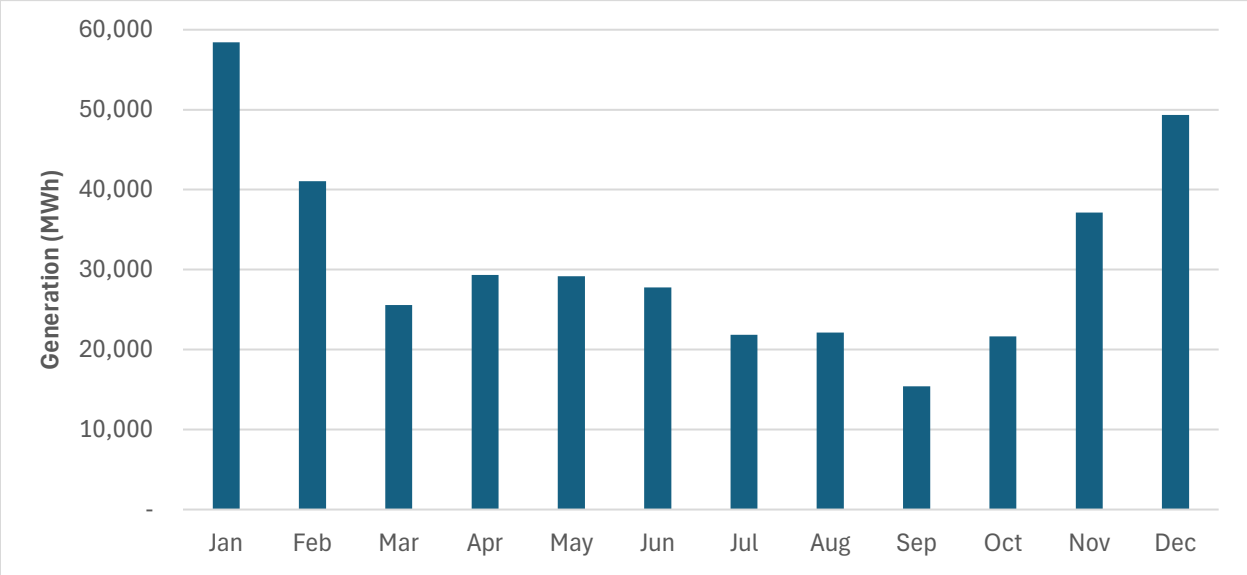
The Jackson Hydroelectric Project (Jackson Project) is located on the Sultan River, north of the City of Sultan, and is owned and operated by the PUD. The project has two large 47.5 MW nameplate Pelton generating units and two smaller 8.4 MW Francis generating units for a total nameplate capacity of 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



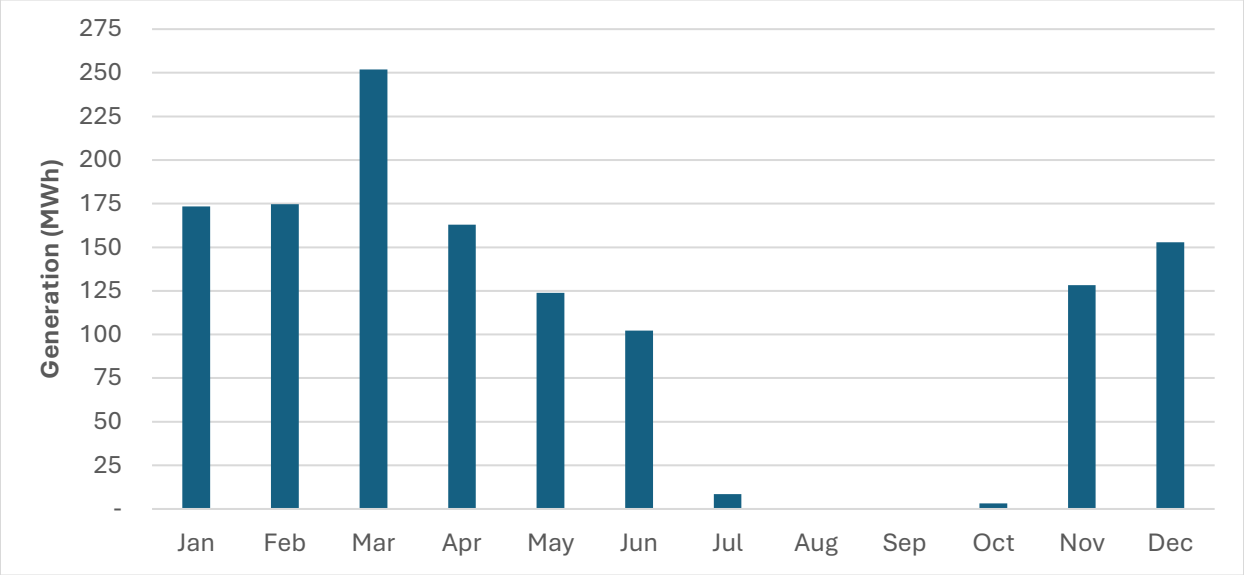
Woods Creek Hydroelectric Project

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

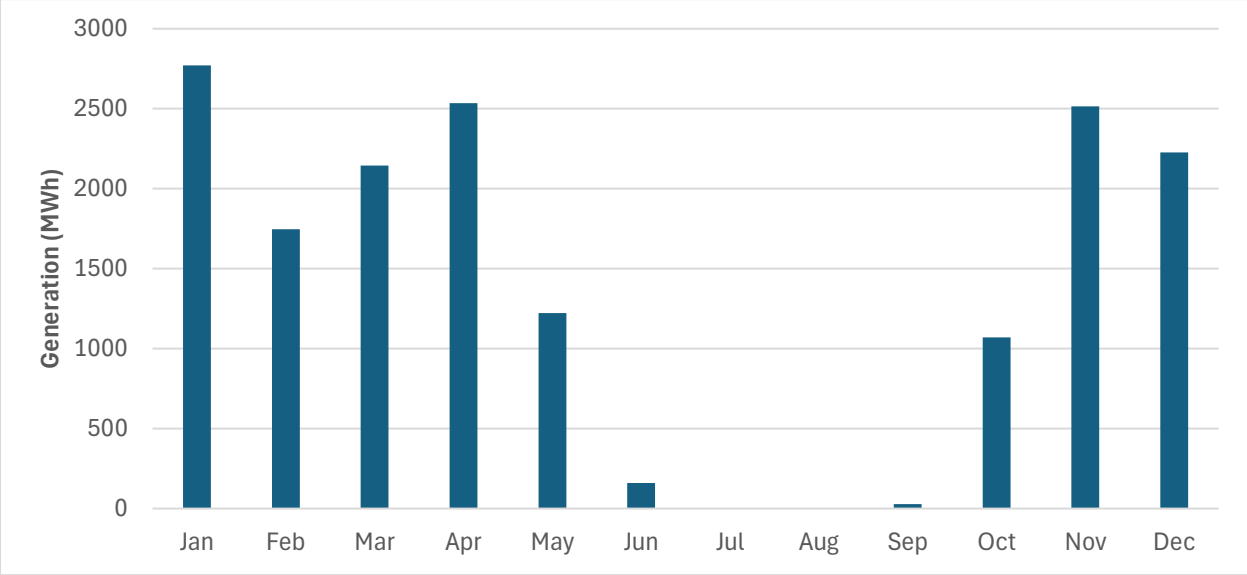
In 2008, the PUD purchased the unconstructed Youngs Creek Hydroelectric Project located on Youngs Creek, a tributary of Elwell Creek near Sultan in Snohomish County. The project is situated above a natural impassable barrier to anadromous fish. Commissioning of this new run of river resource, with single 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.

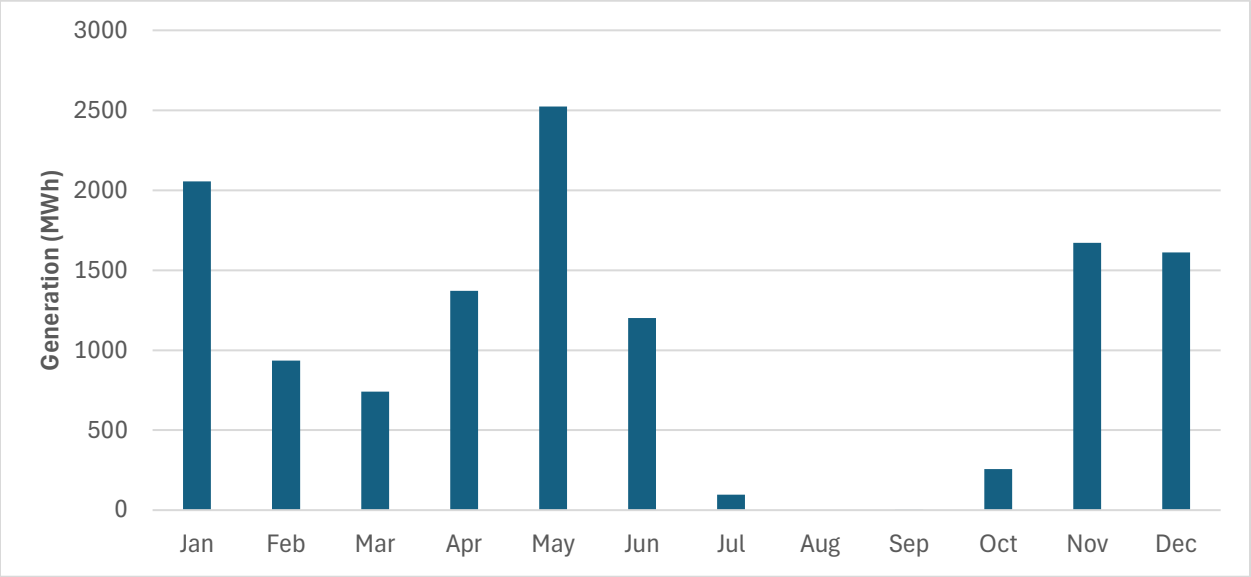
Figure 2-7 Youngs Creek Average Monthly Generation 2021-2024



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.

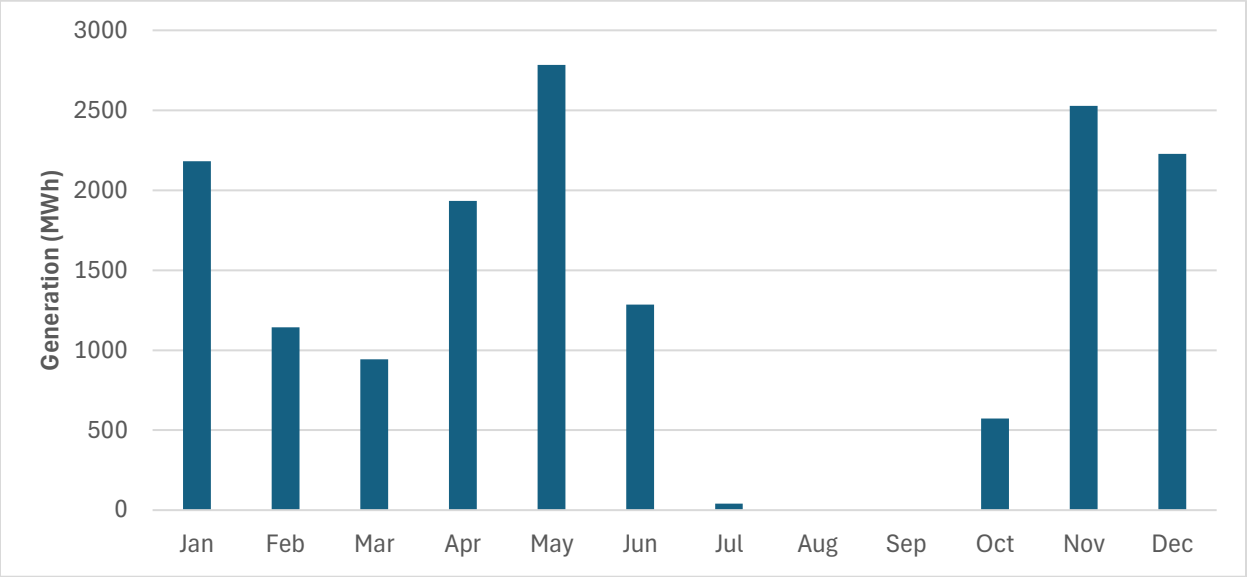
Figure 2-8 Calligan Creek Average Monthly Generation 2021-2024



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:

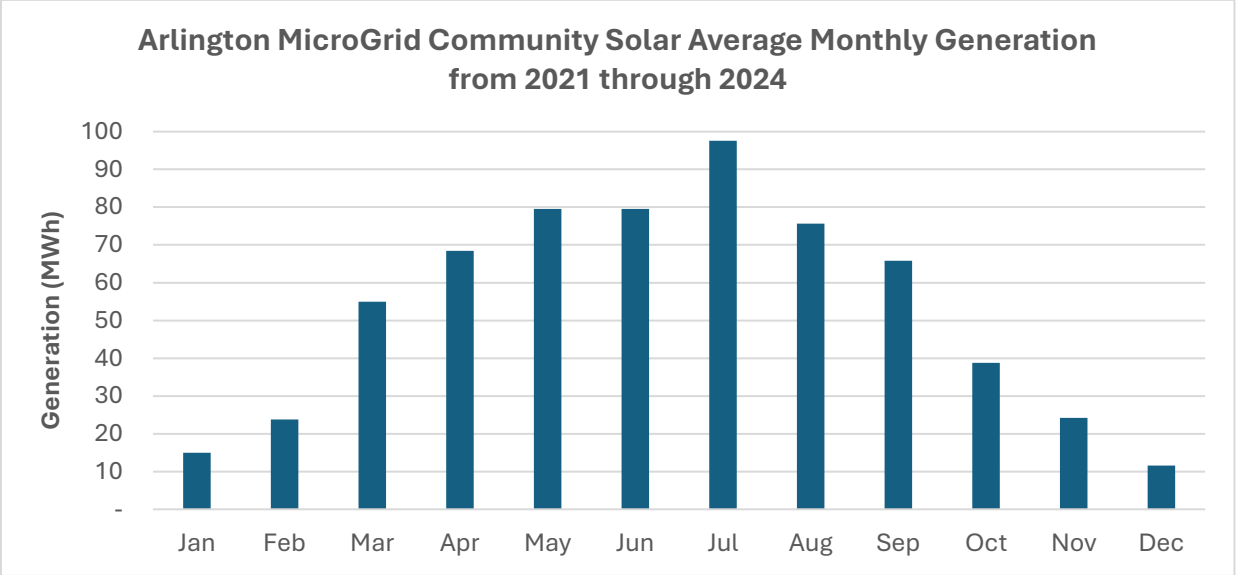
- 500 kW utility scale solar array
- 1000 kW/1500 kWh lithium-ion battery
- Two vehicle-to-grid (V2G) charging systems with connected electrical vehicles
- Clean Energy Center (CEC) to provide the load and demonstration area
- Backup data center for PUD information technology resilience.

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.

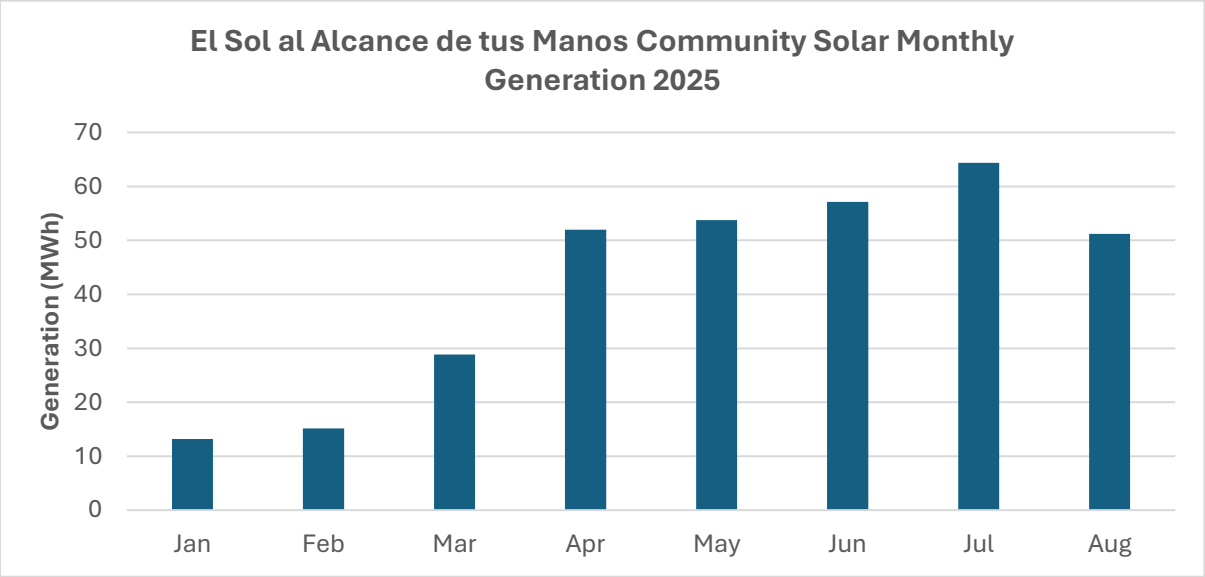
Figure 2-10 Arlington Solar Average Monthly Generation 2021-2024



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.

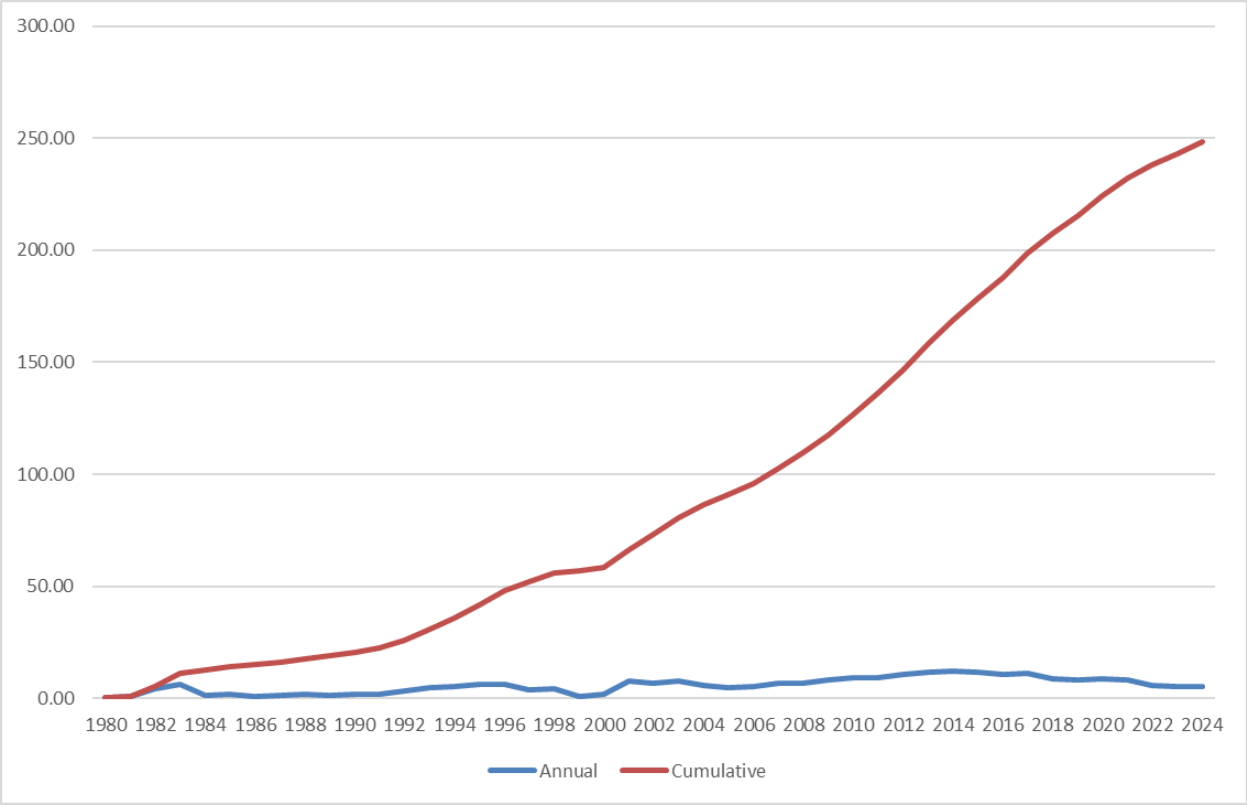
Existing Demand Side Resources

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.

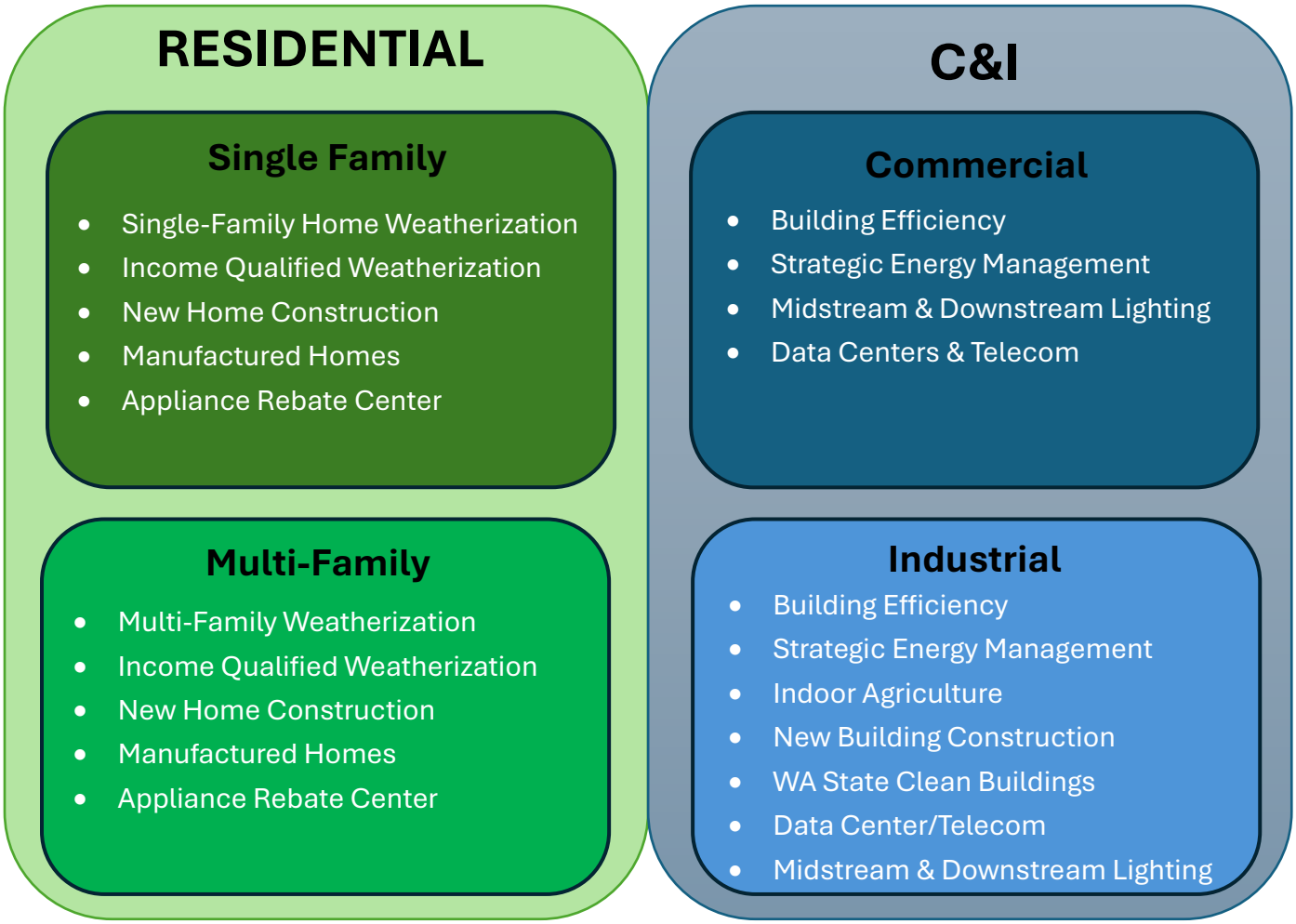
Figure 2-12 Annual and Cumulative Conservation Achievements 1980-2024



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	

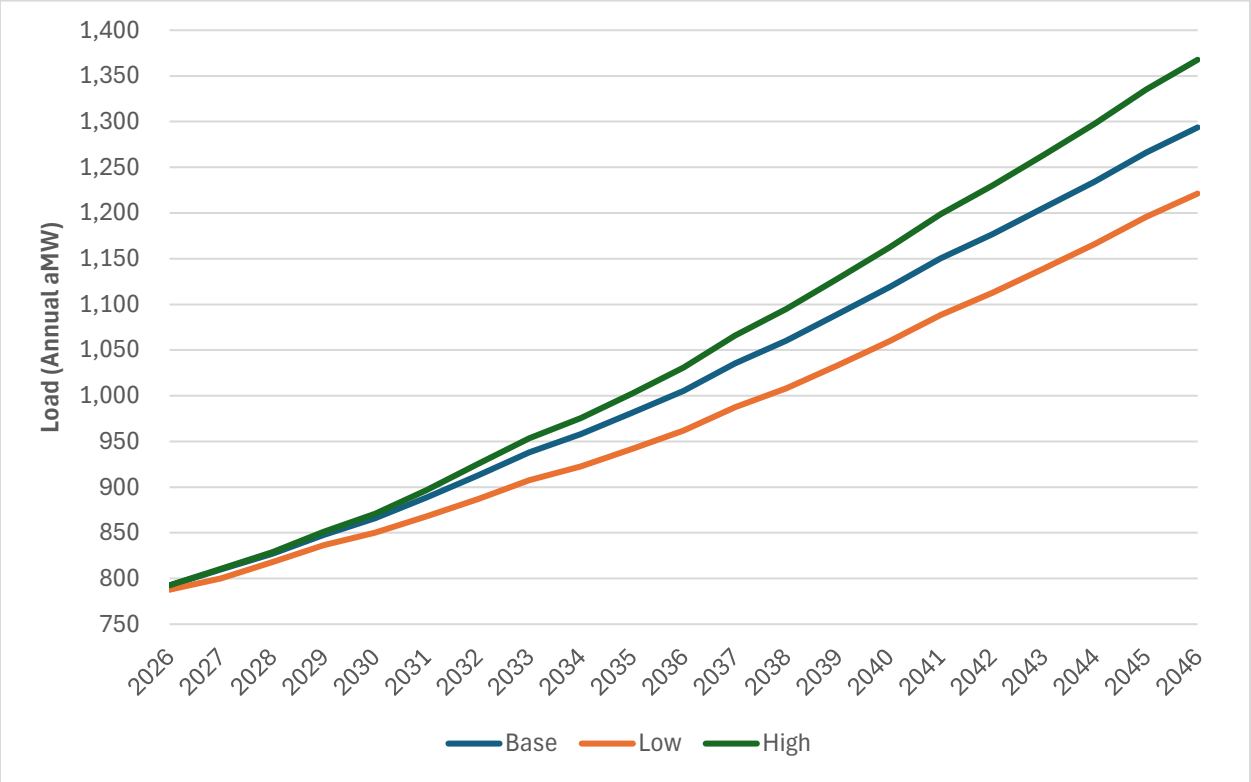
Load Forecasts

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



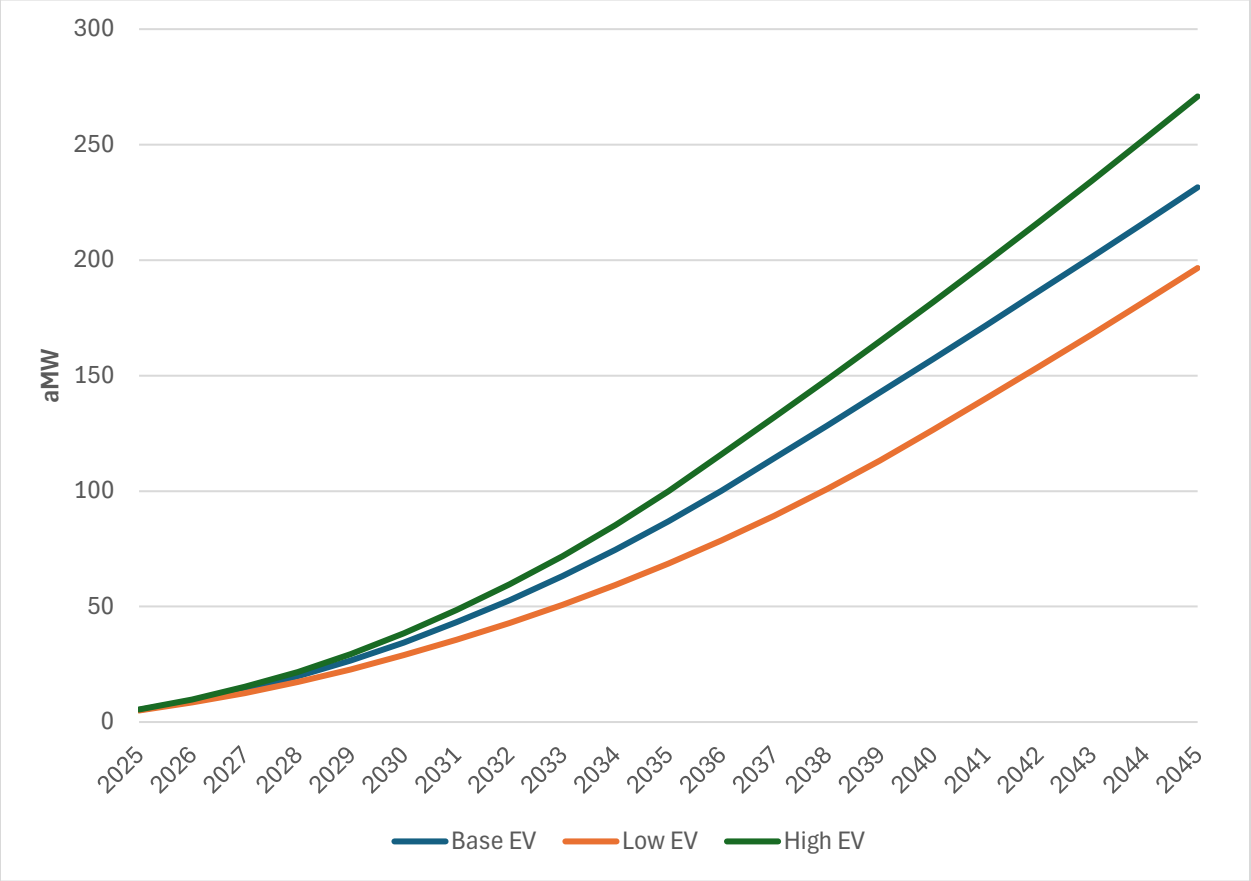
Electric Vehicle Adoption

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)

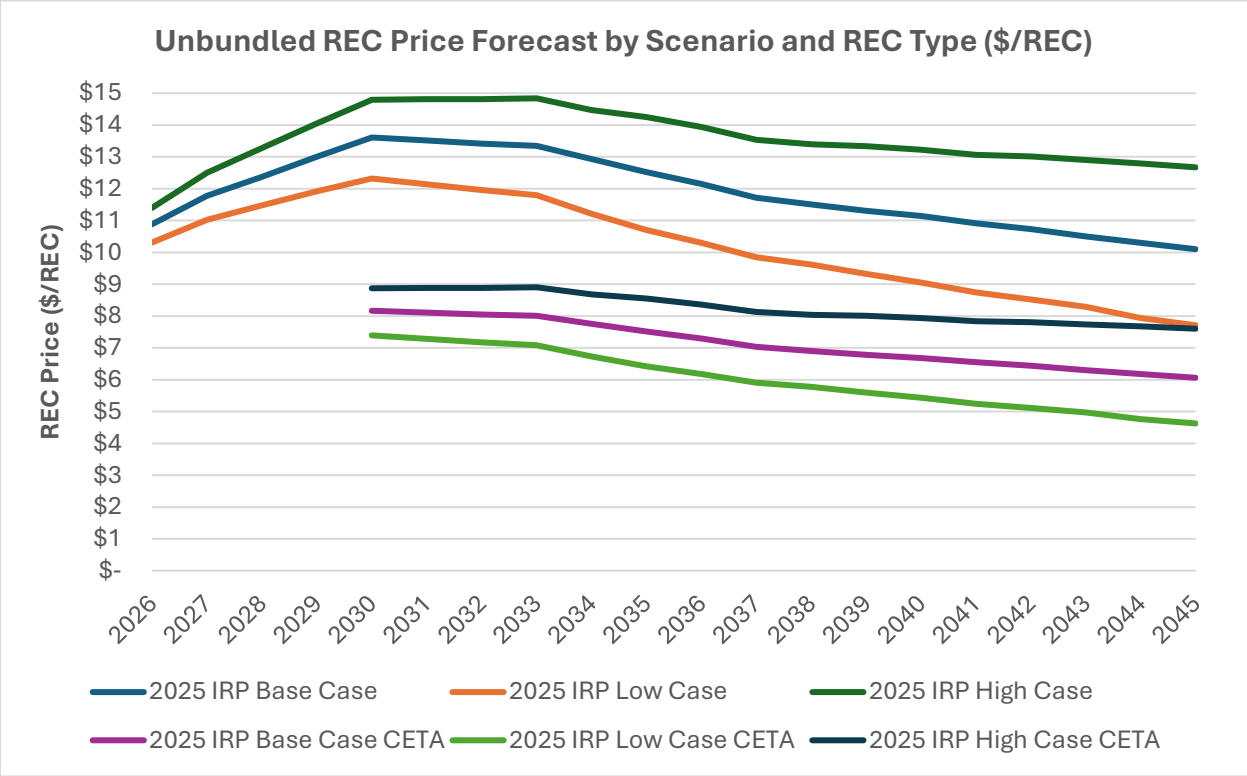


REC Price Forecast

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.

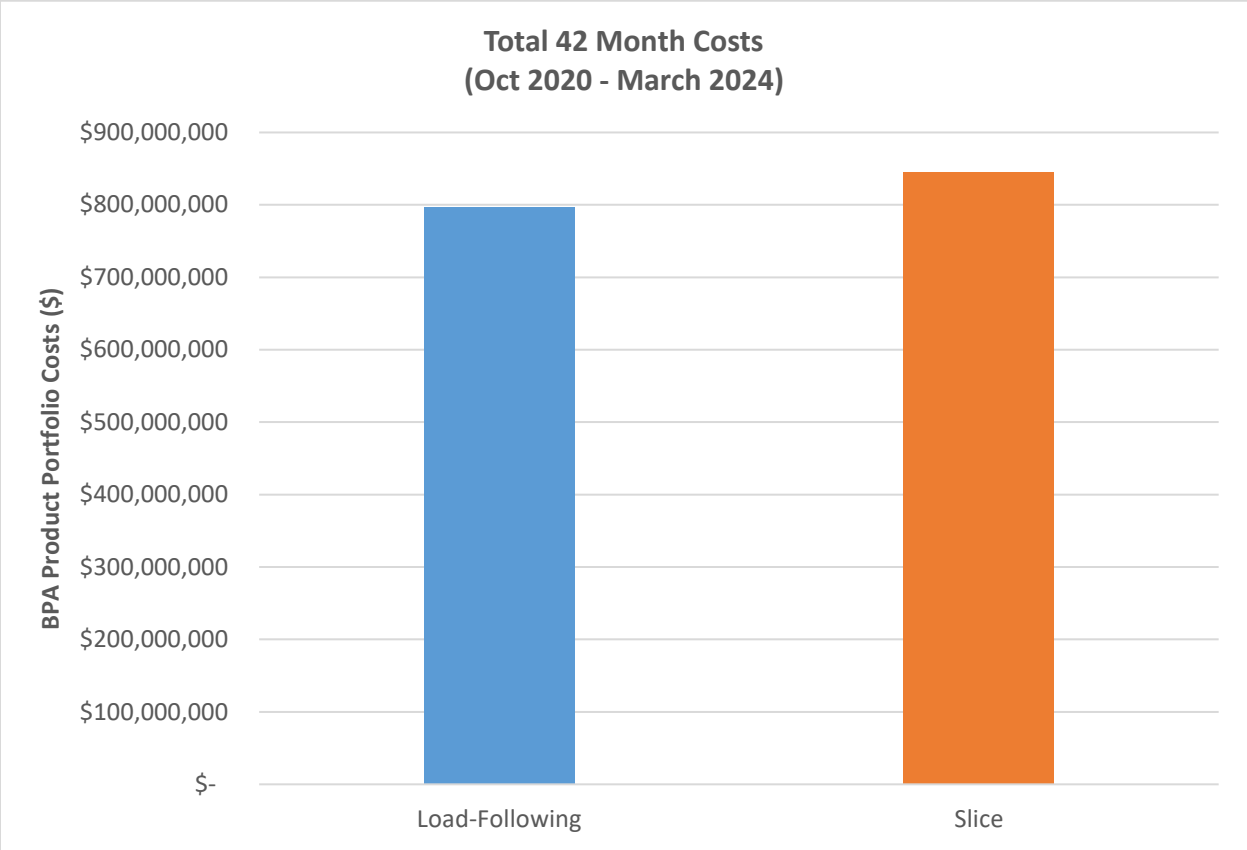
BPA Product Switch

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.

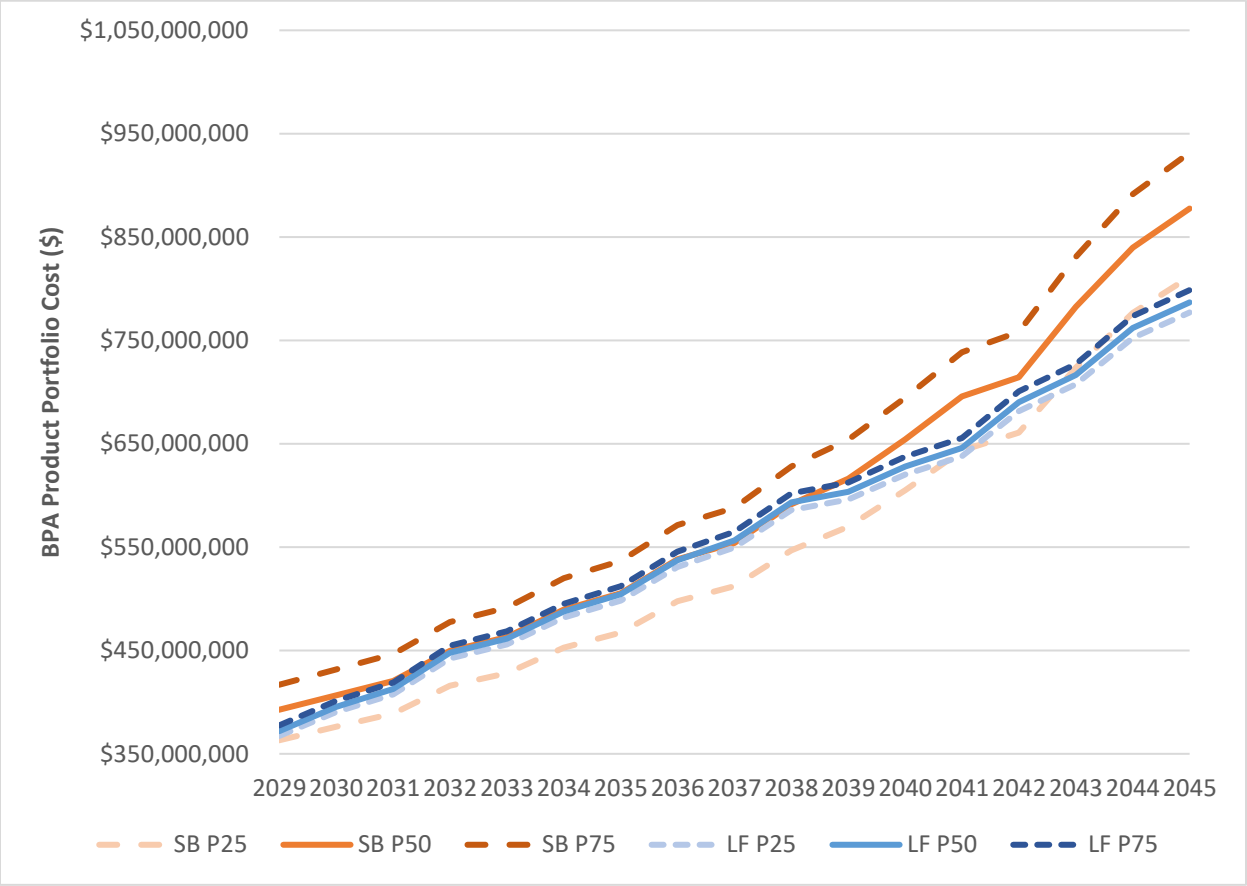
Figure 4-6 Look-Forward Analysis Results FY26 - FY28



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

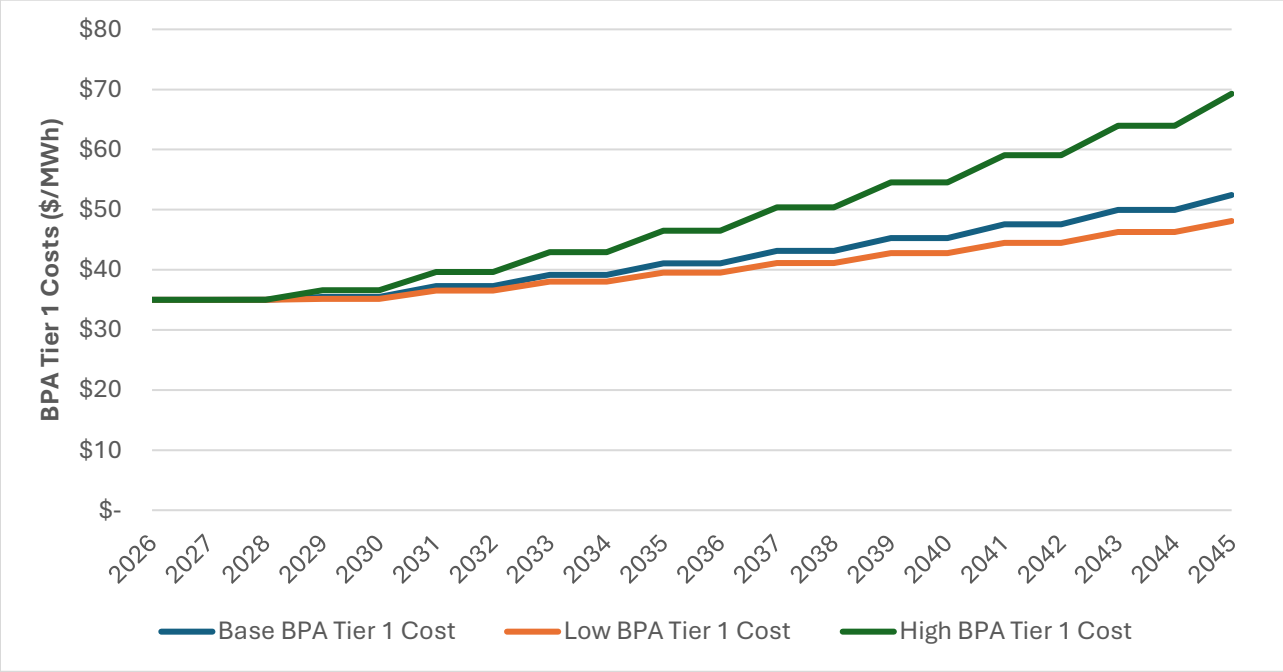
On October 1, 2028, under the new POC contract the BPA Tier 1 system size will be fixed at 7250 aMW granting a stable planning baseline for Tier 1 allocation.

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)

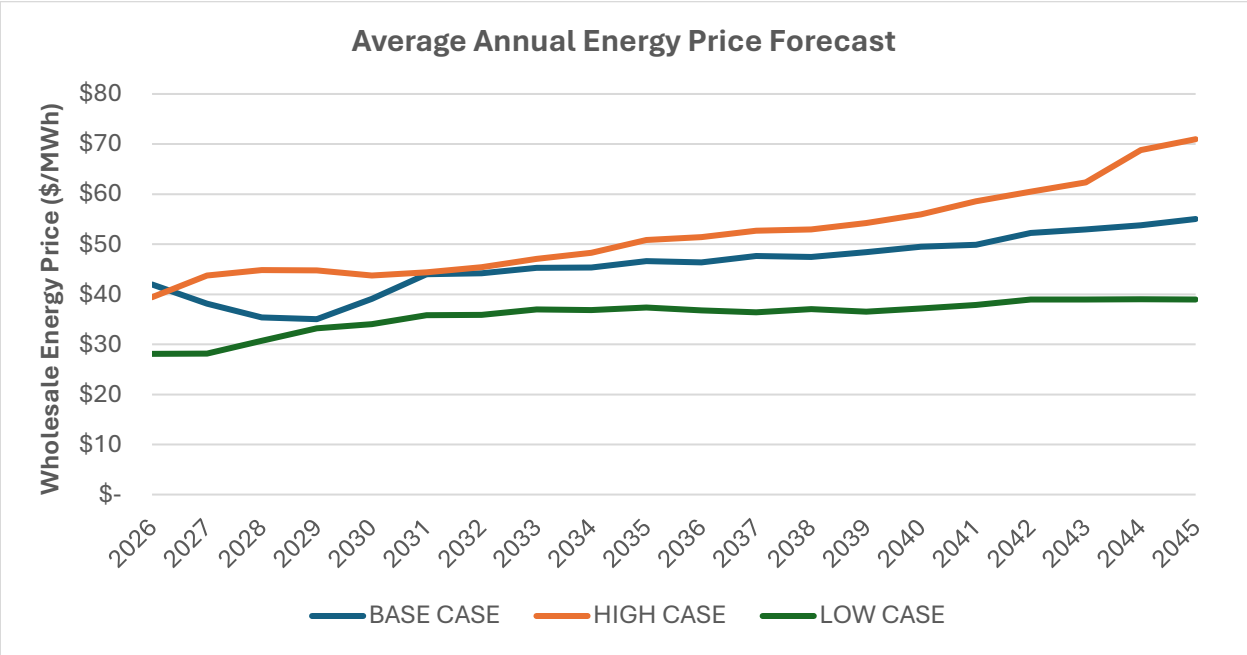
Year	Carbon Price ($/MWh)
2026	$83.29
2027	$86.63
2028	$90.12
2029	$93.66
2030	$97.42
2031	$101.17
2032	$106.71
2033	$110.79
2034	$113.94
2035	$117.91
2036	$121.16
2037	$124.45
2038	$128.60
2039	$131.99
2040	$136.26
2041	$139.75
2042	$144.15
2043	$148.61
2044	$155.05
2045	$159.67

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.

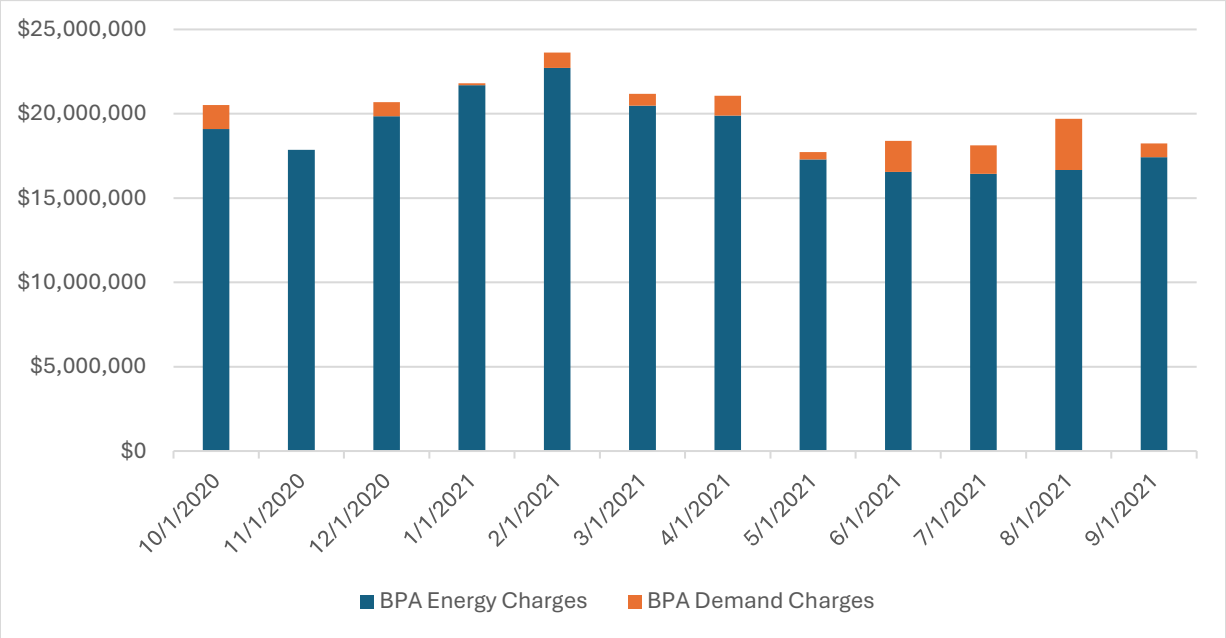
Solving Energy Needs

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-

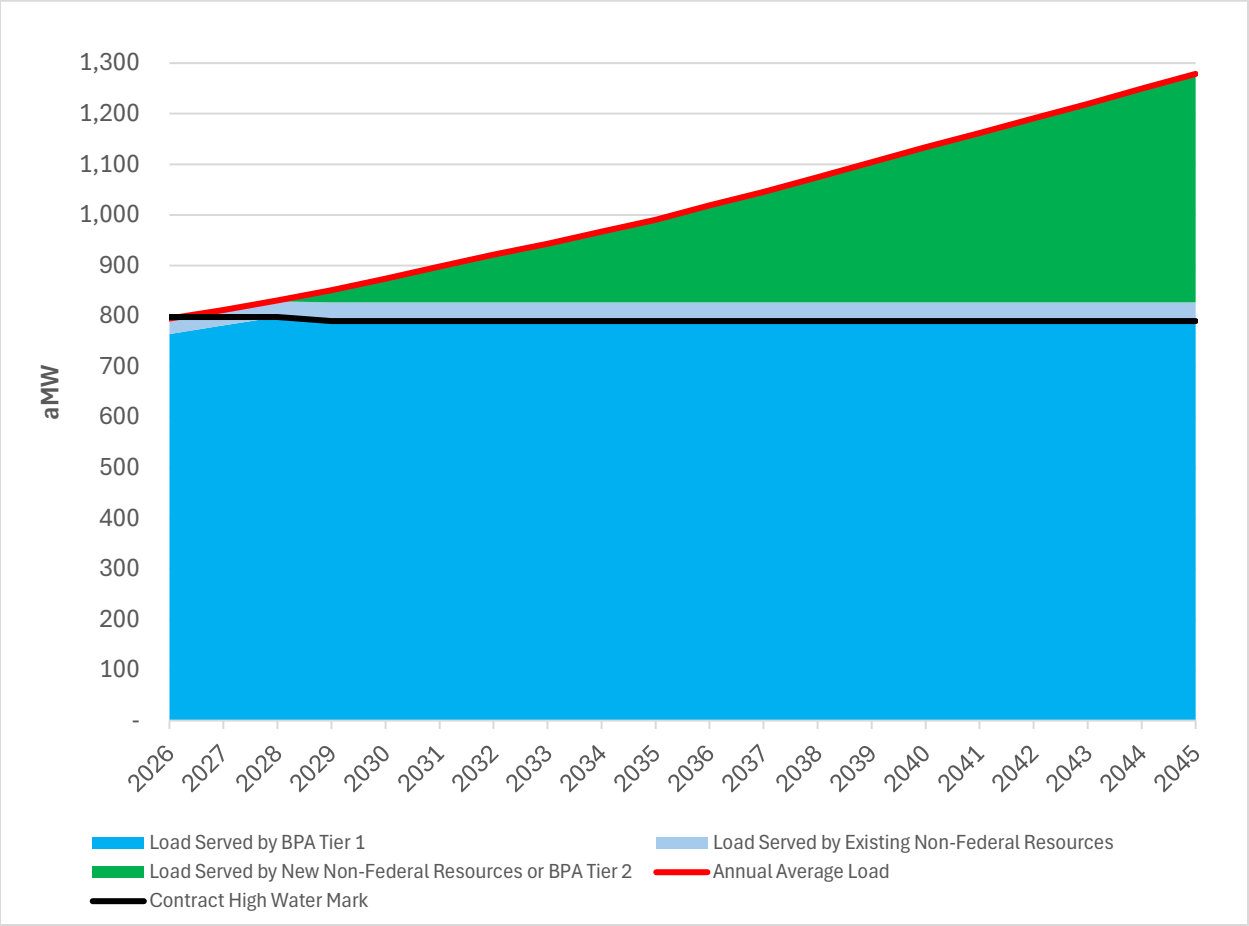
[12] Energy Information Administration. January 27, 2025. Forecast wholesale power prices and retail electricity prices rise modestly in 2025. https://www.eia.gov/todayinenergy/detail.php?id=64384#:~:text=We%20forecast%20that%20the%2011%20wholesale%20prices%20we,2025%20%28weighted%20by%20demand%29%2C%20up%207%25%20from%202024.

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

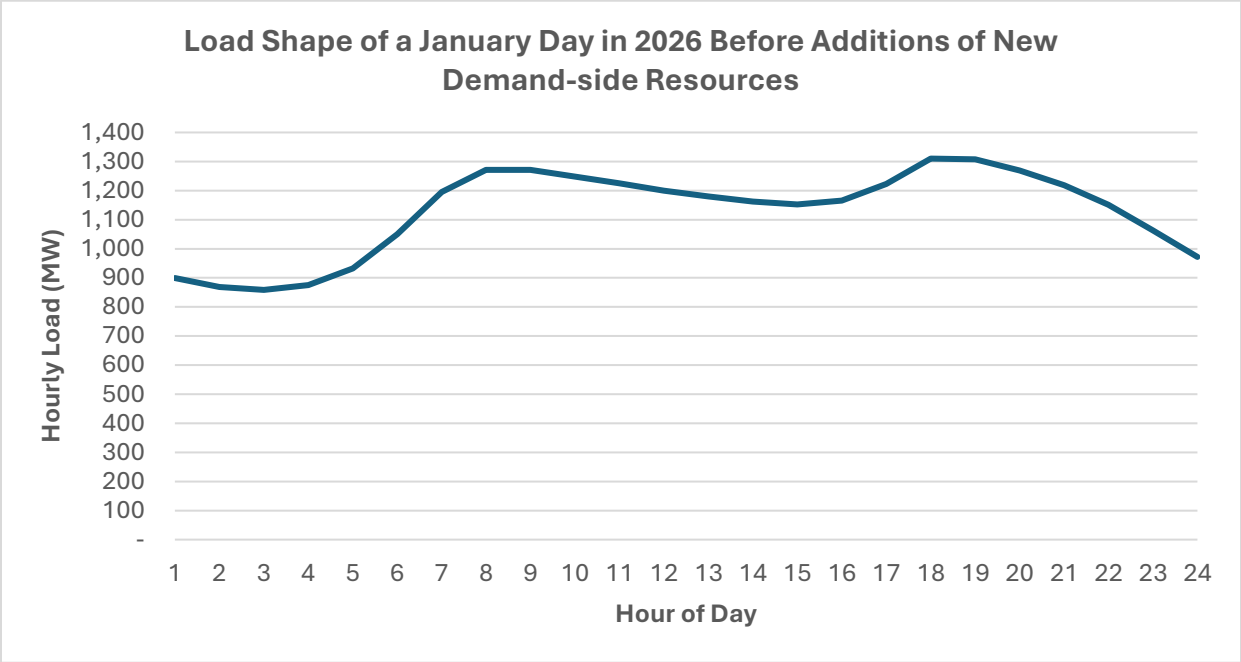


BPA Tier 2 energy is offered in two main product forms in the Post-2028 BPA Power contract: Short-term Tier 2 and Long-term Tier 2. The characteristics of Tier 2 products are described in **SECTION 5 BPA TIER 2.** Non-federal resources are demand-side or supply-side resources procured by the PUD for 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

$$Monthly\ Demand\ Charge = Monthly\ Capacity\ Price * (Peak\ Hour\ Load - HLH\ Load\ in\ aMW - Contract\ Demand\ Quantity)$$

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

$$Monthly\ Demand\ Charge = Monthly\ Capacity\ Price * (Peak\ Hour\ Load - Average\ Load\ in\ aMW - RICc\ capacity\ credit)$$

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

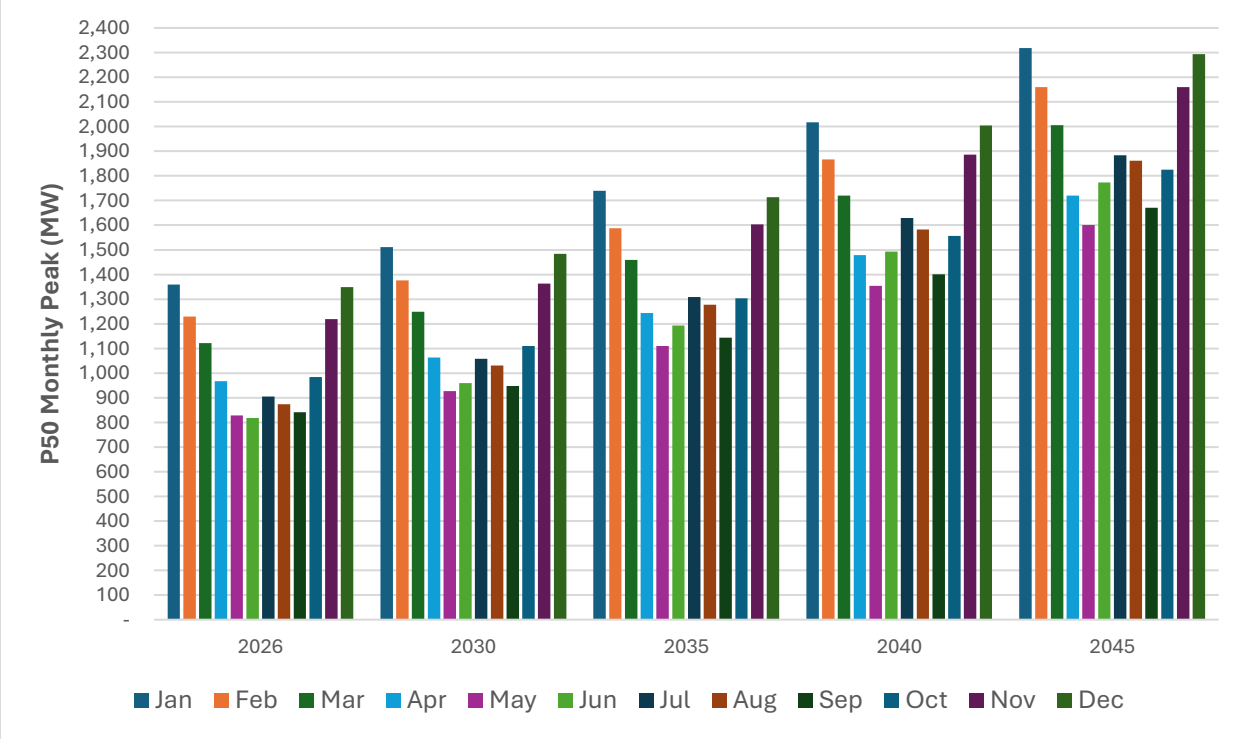
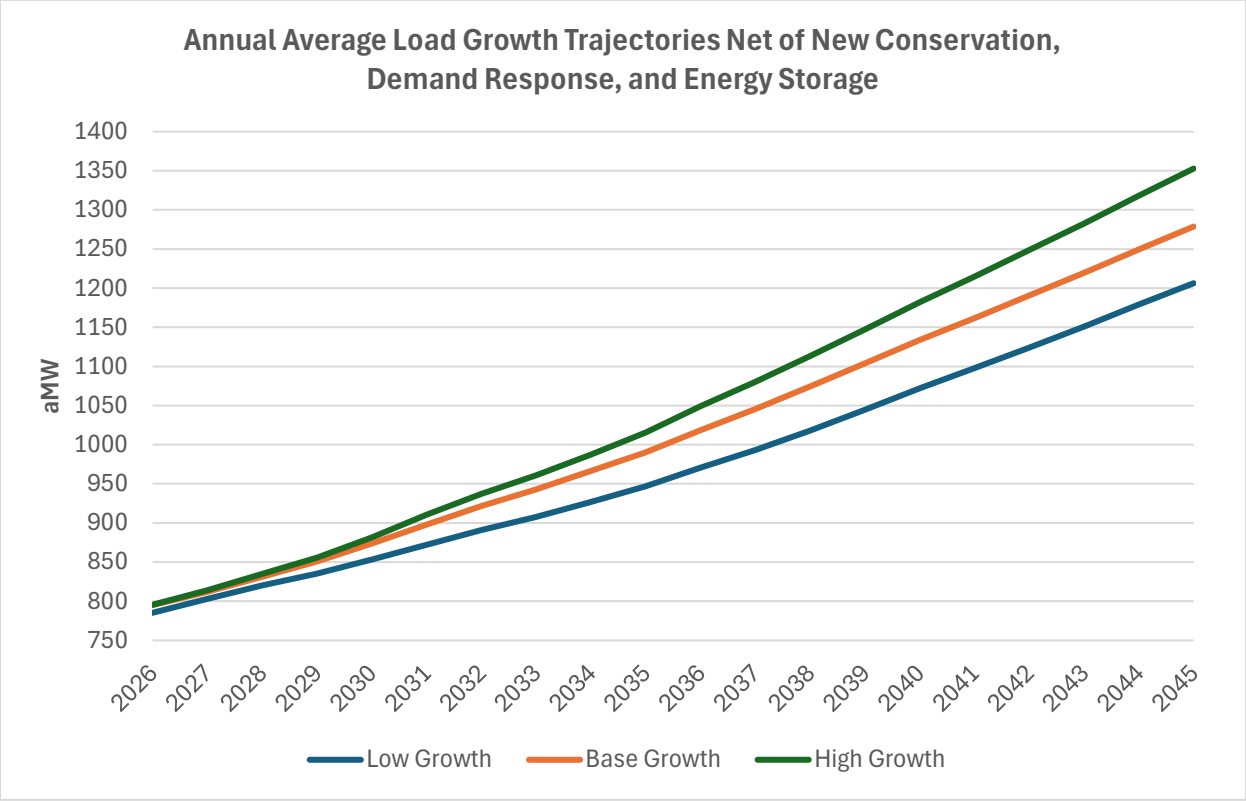


Figure 5-7 below shows the three unique annual peak load growth trajectories at the fiftieth percentile (P50) before new demand-side or supply-side resource additions. Each scenario or sensitivity utilizes one of these three load growth trajectories. Generally, the PUD forecasts annual peak load growth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

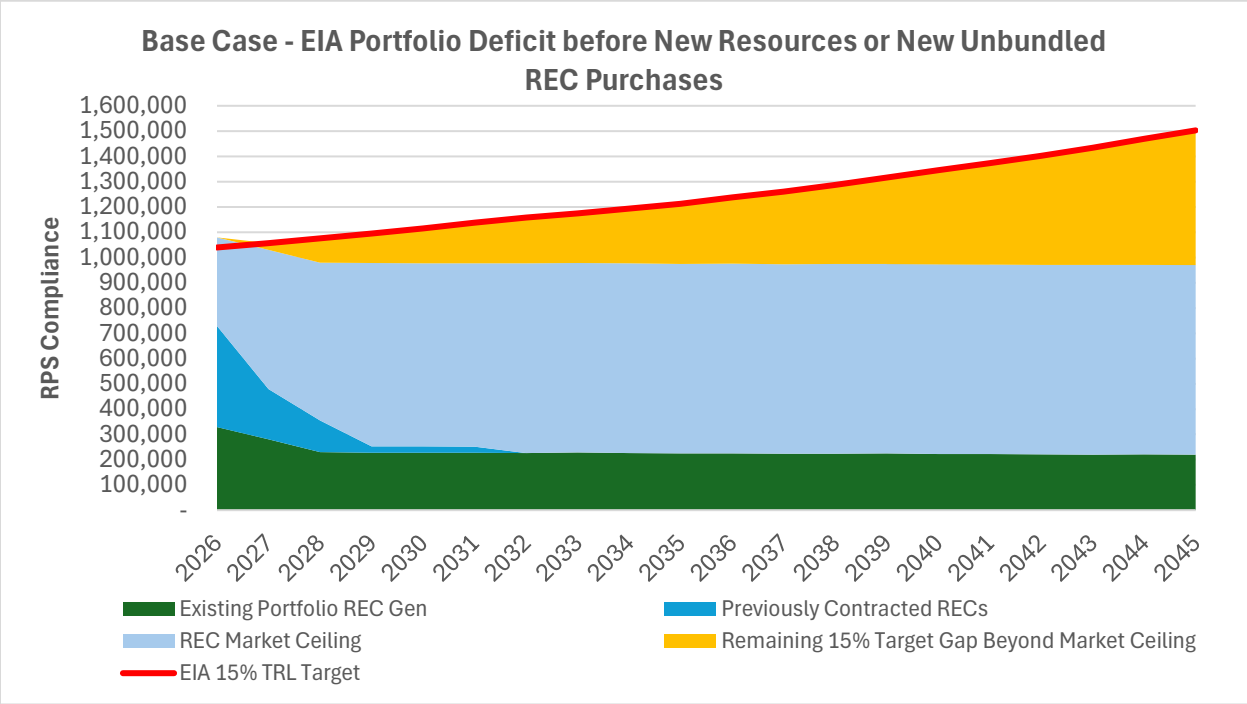
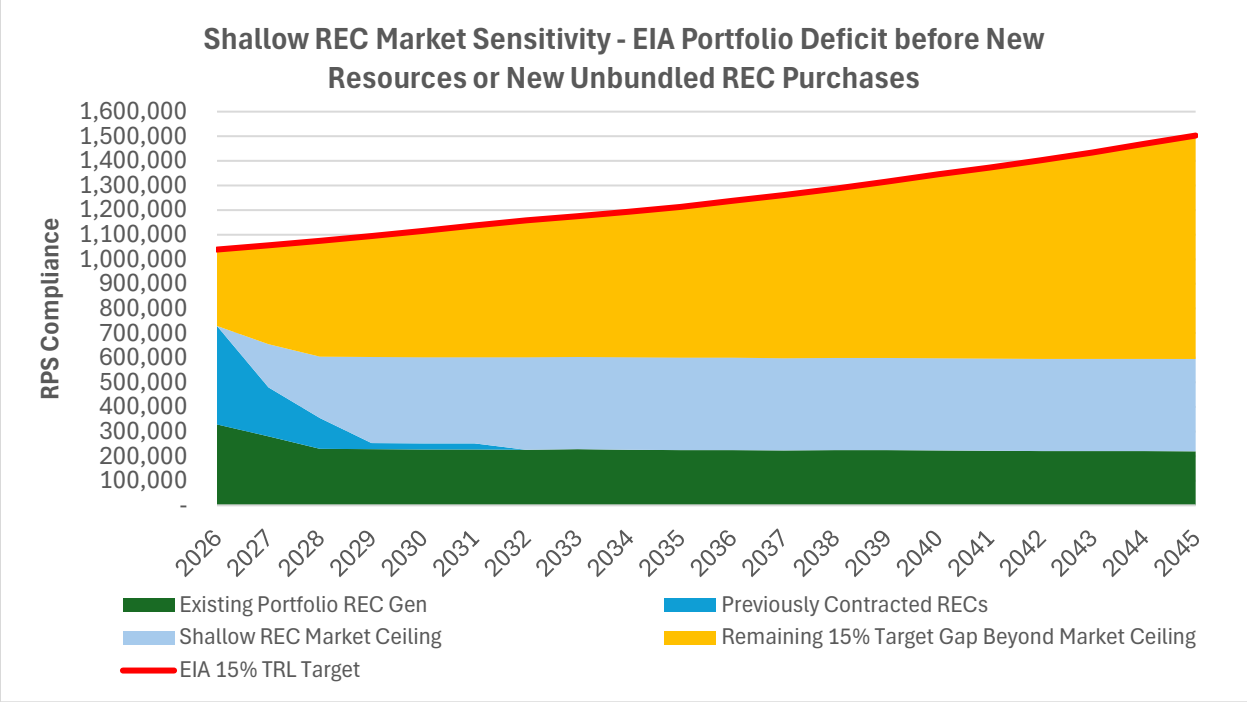


Figure 5-9 EIA Portfolio Needs Before Resources Shallow REC Market



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.

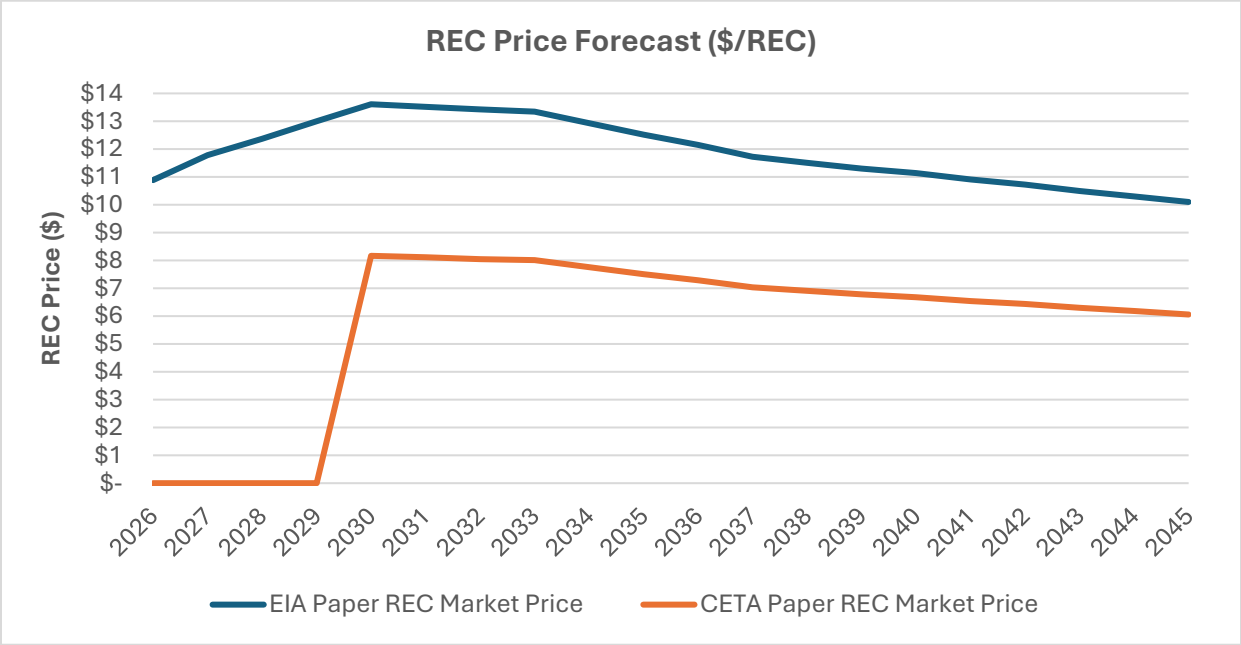
$$\frac{Peak\ Reduction\ Contribution\ of\ Resource\ (MW)}{Utility\ System\ Peak\ (MW)} \times Total\ Retail\ Load\ of\ Utility\ (MWh)$$

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

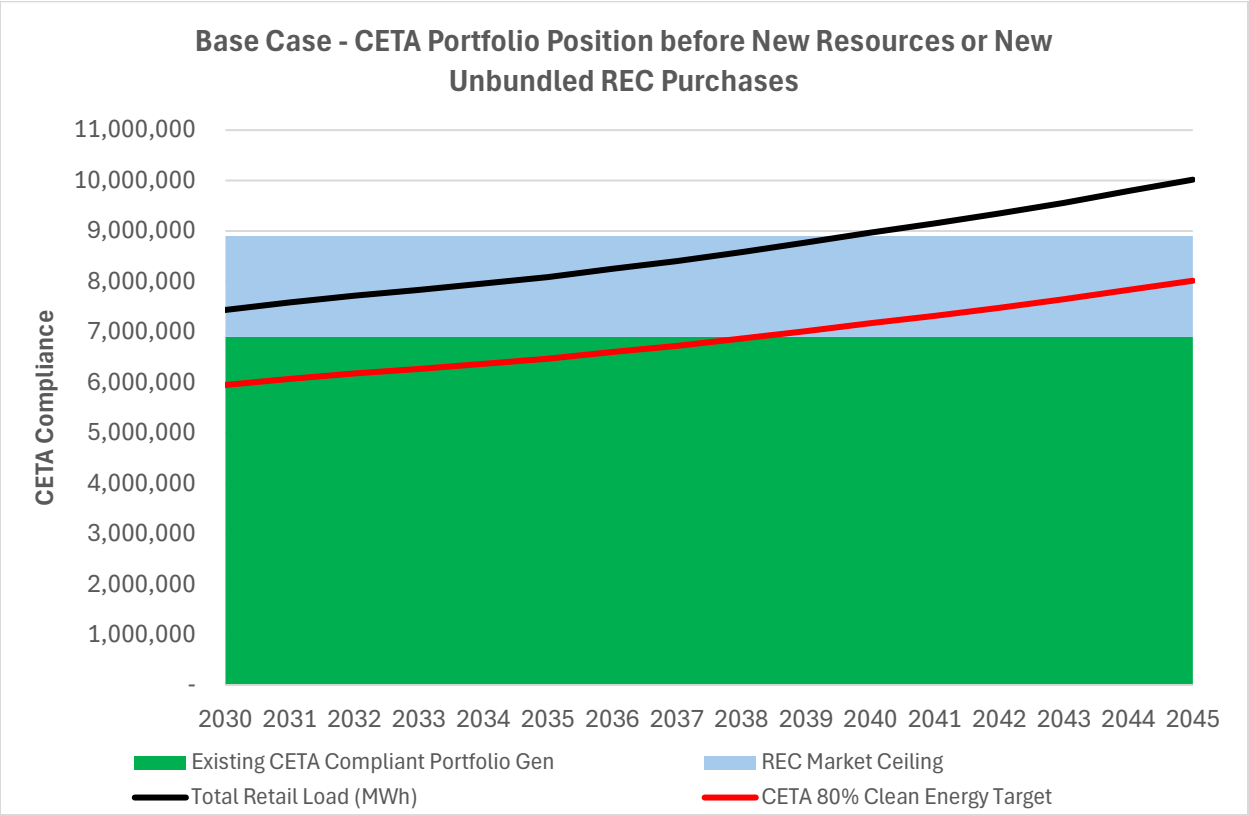
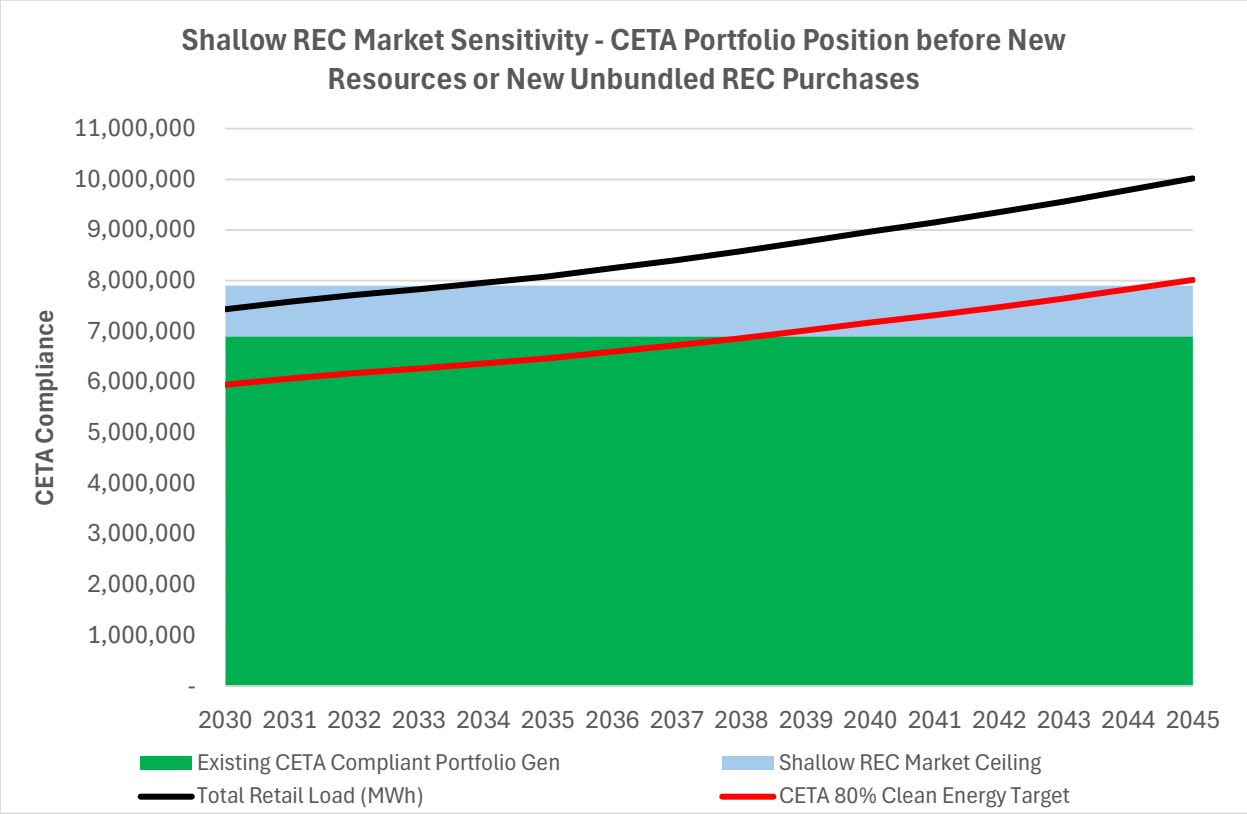


Figure 5-12 CETA Shallow REC Market Portfolio Position Before Resources or REC Purchases



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

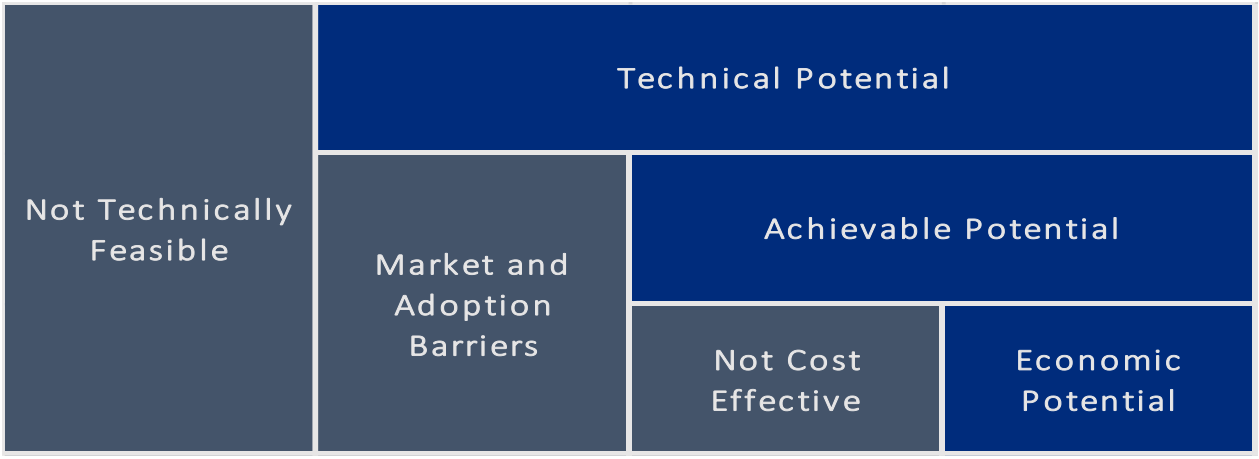


Figure 5-14 and Figure 5-15 illustrate the 2025 CPA's conservation supply curve, separated by bundle. This supply curve facilitates comparison of demand-side resources to supply-side resources. Each section in the chart below represents the amount of achievable technical conservation potential (annual 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

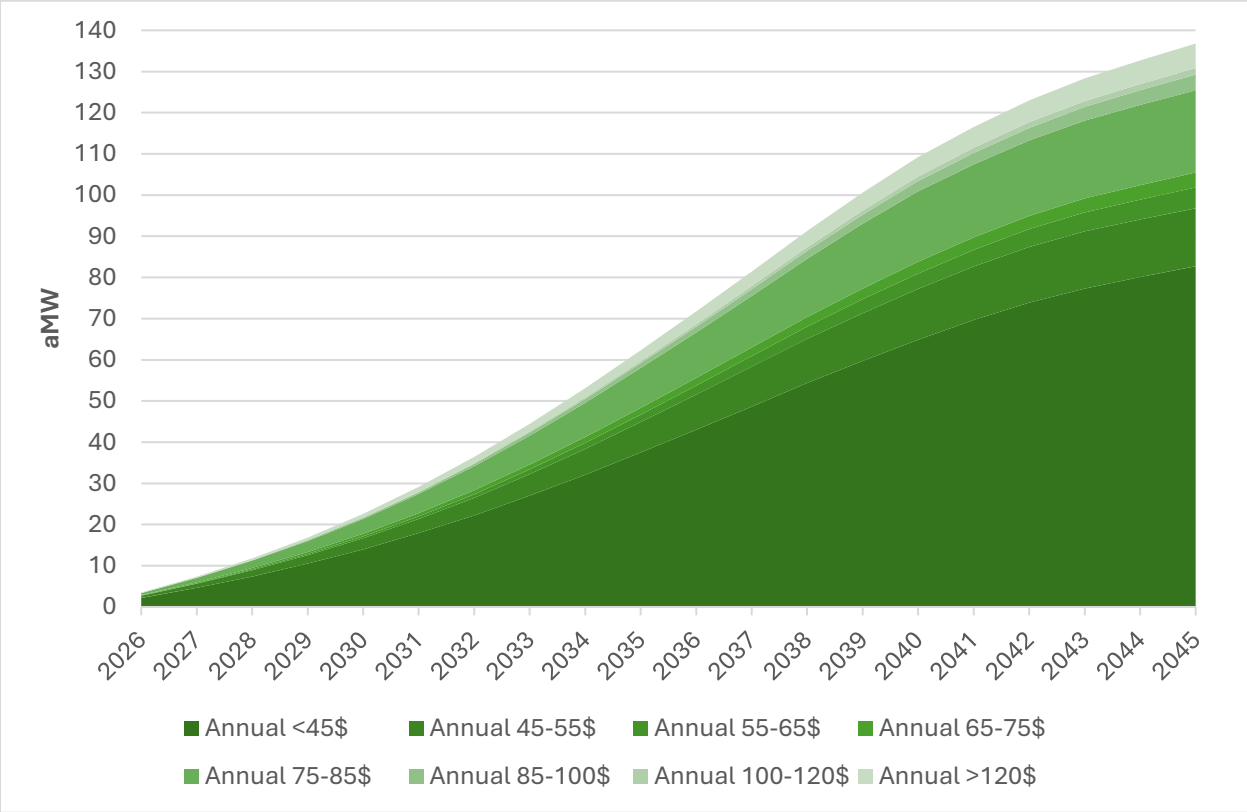
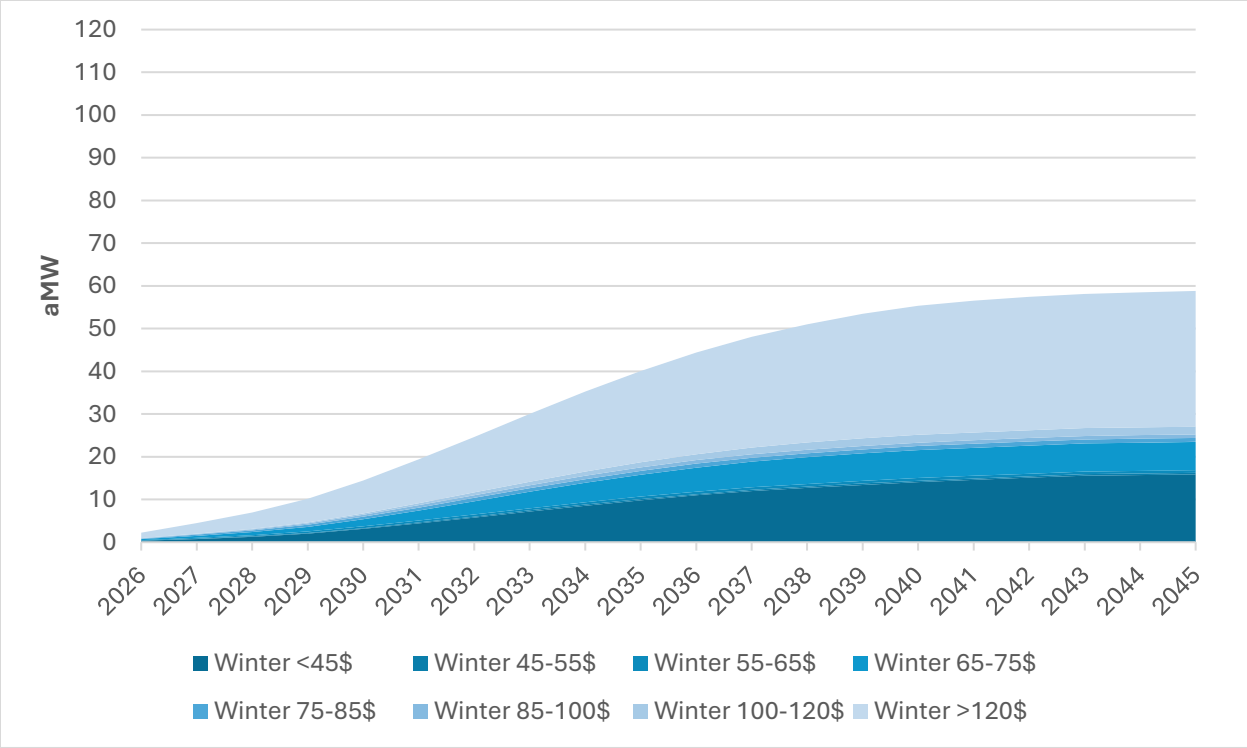


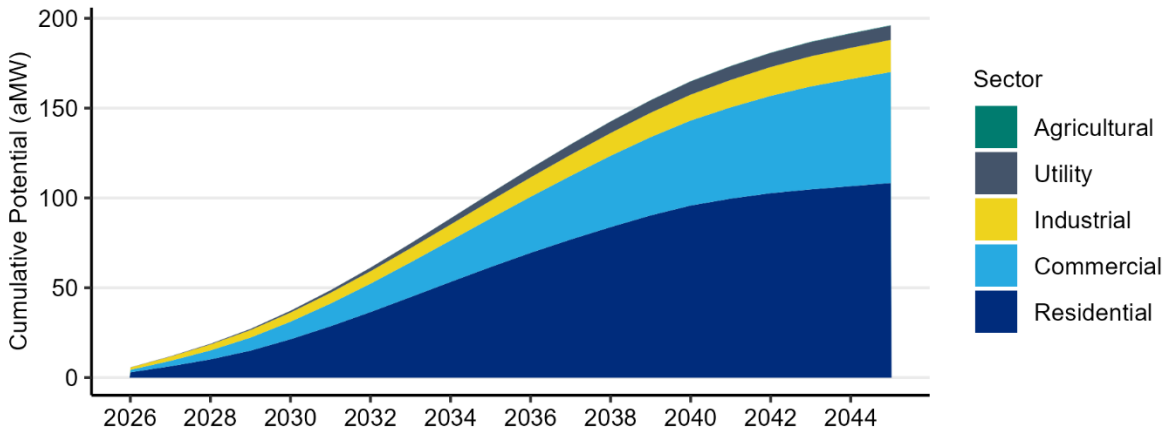
Figure 5-15 Cumulative Winter Achievable Technical Potential Supply Curve 2026-2045



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

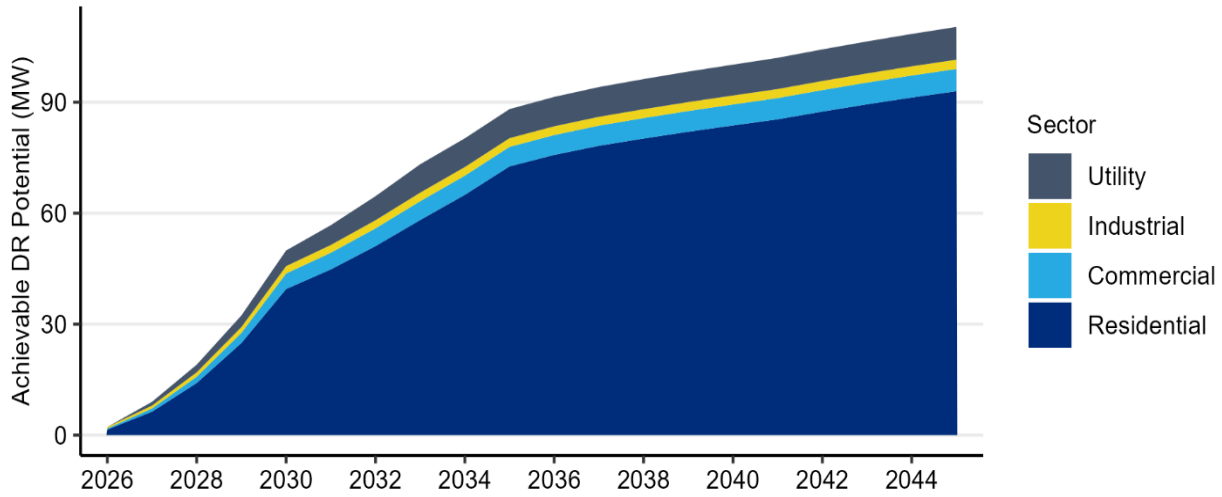
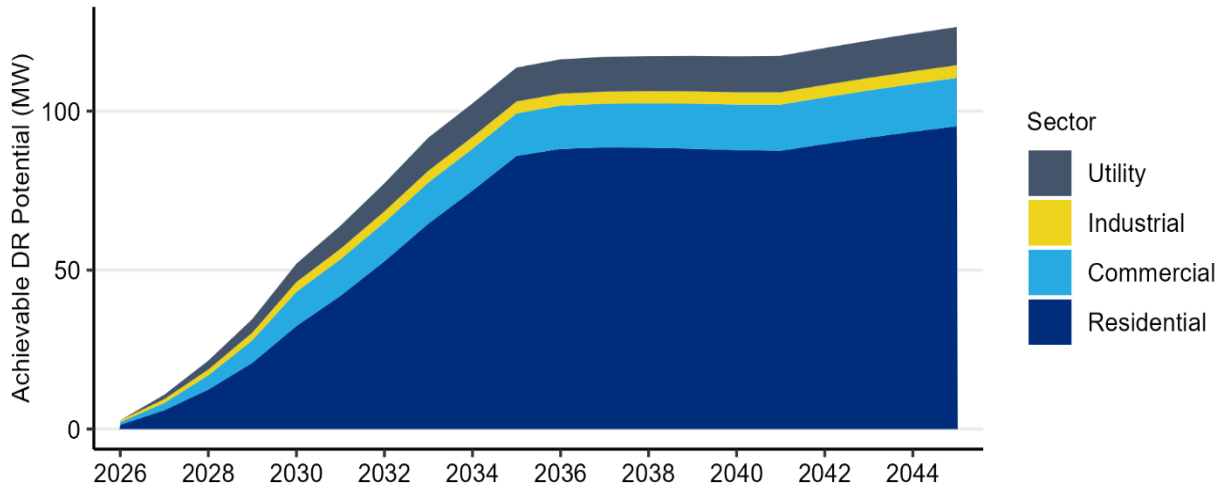


Figure 5-19 Summer DR by Sector



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

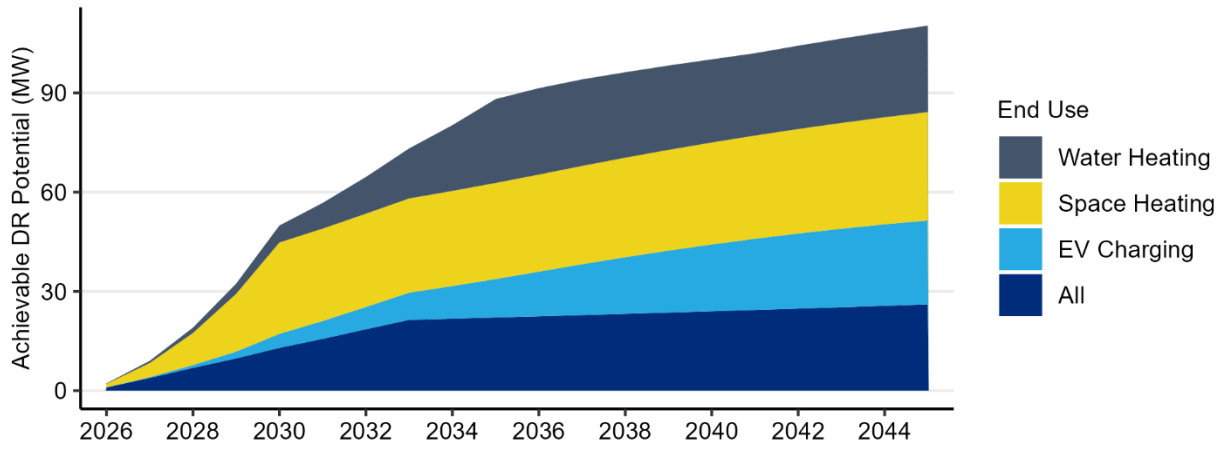
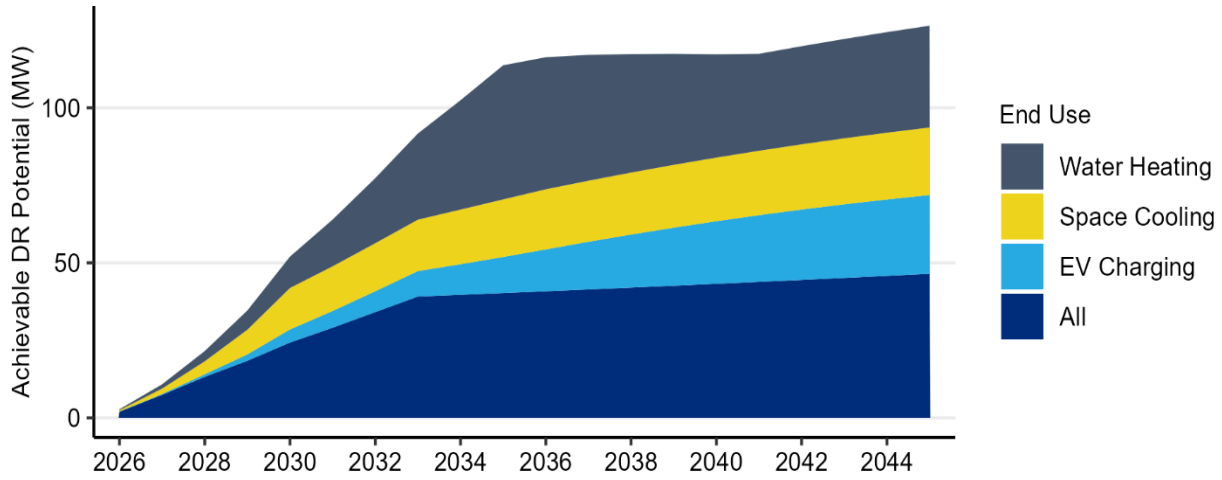


Figure 5-21 Summer DR by End Use



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)

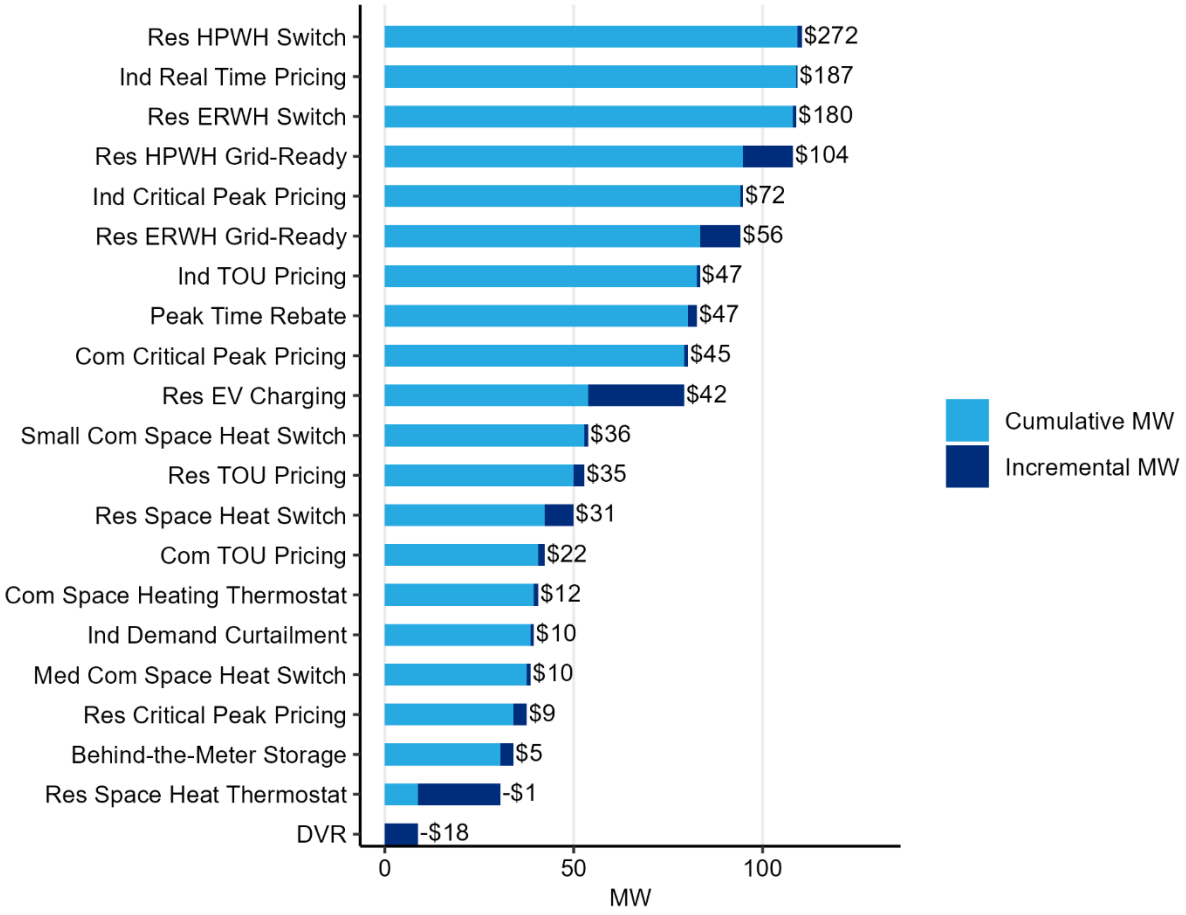
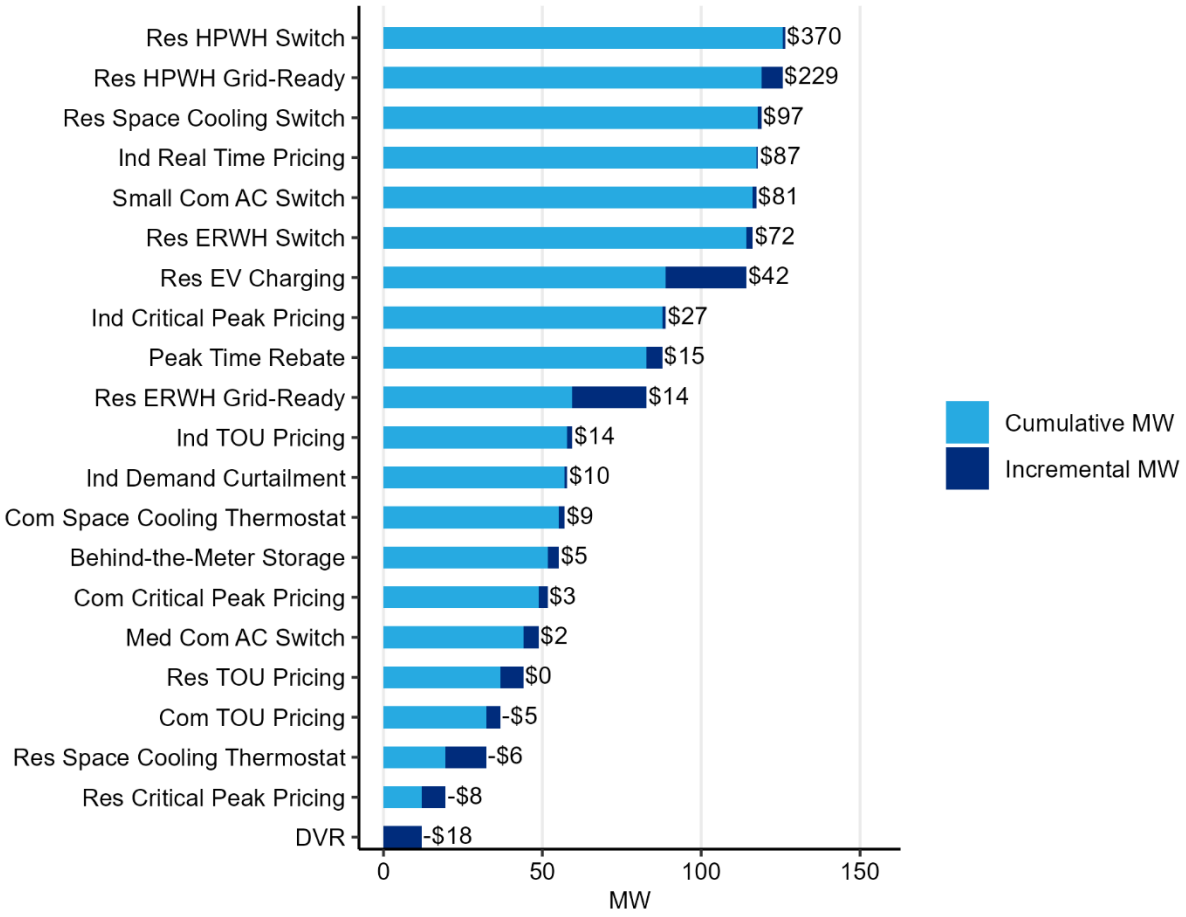


Figure 5-23 Summer DR Supply Curve (MW and $/kW-year)



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

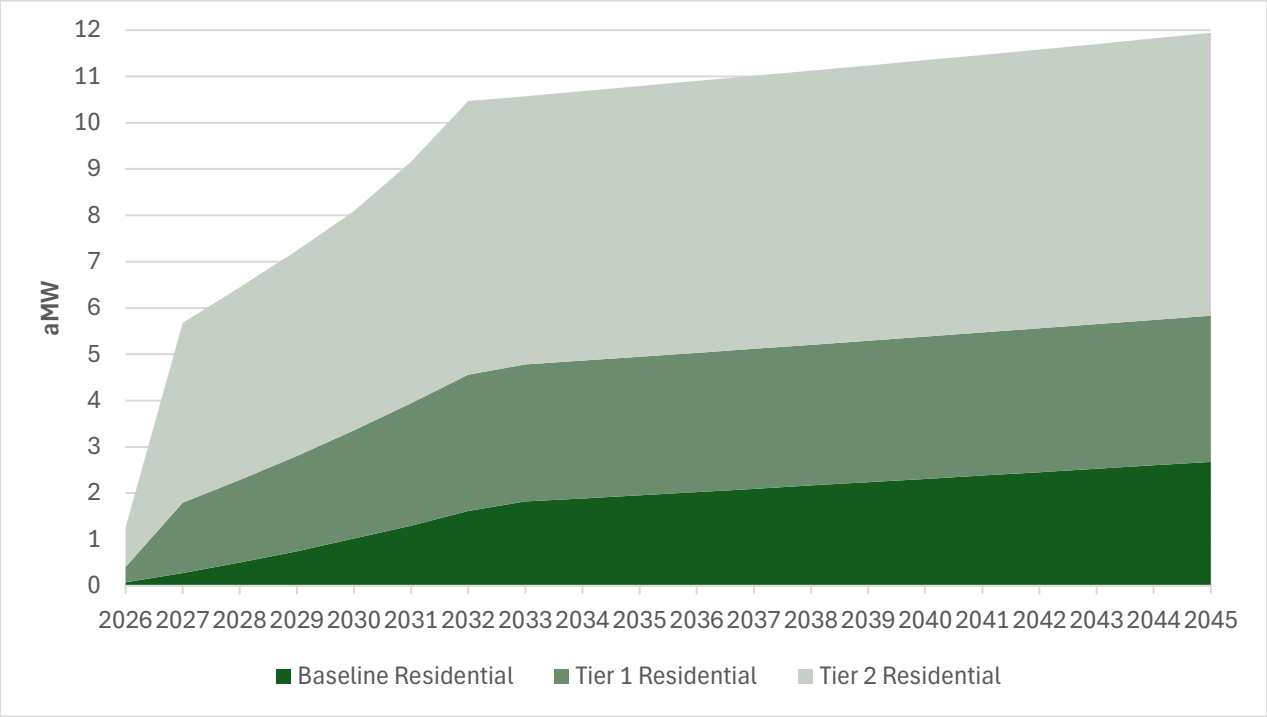


Figure 5-25 Small Commercial and Industrial Solar Potential by Incentive Level

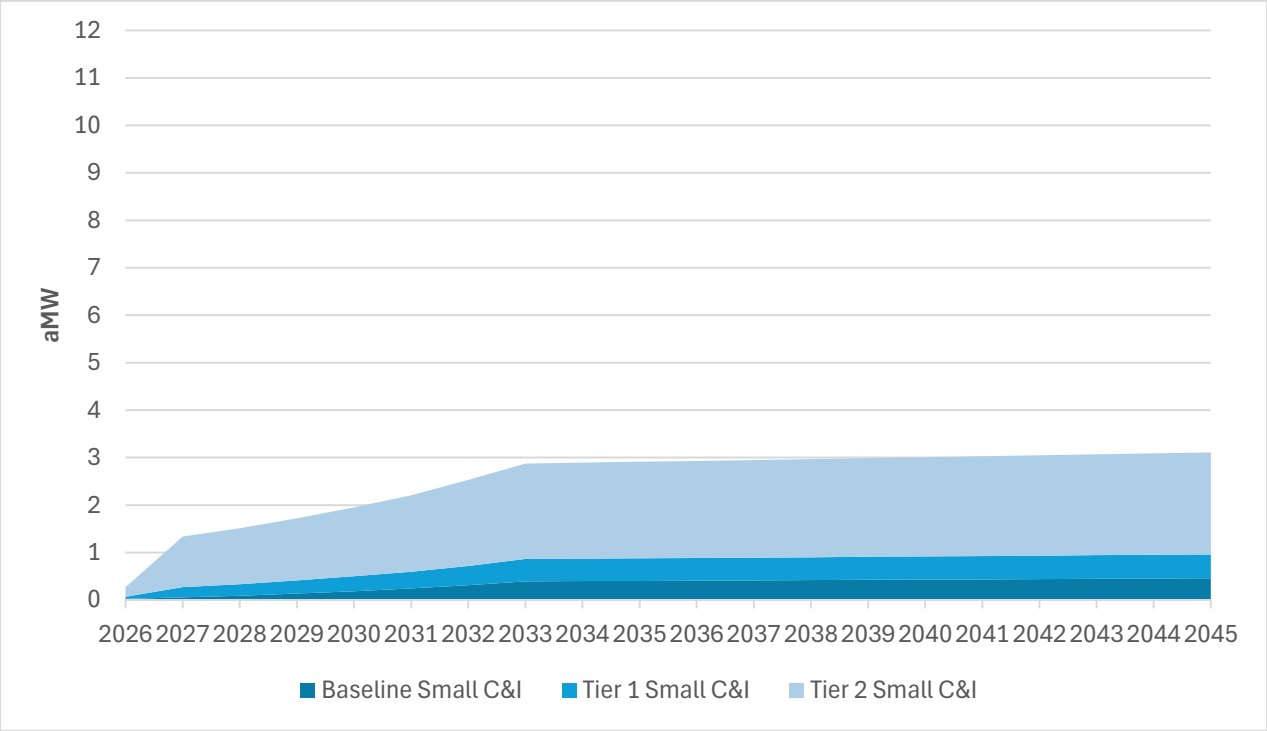
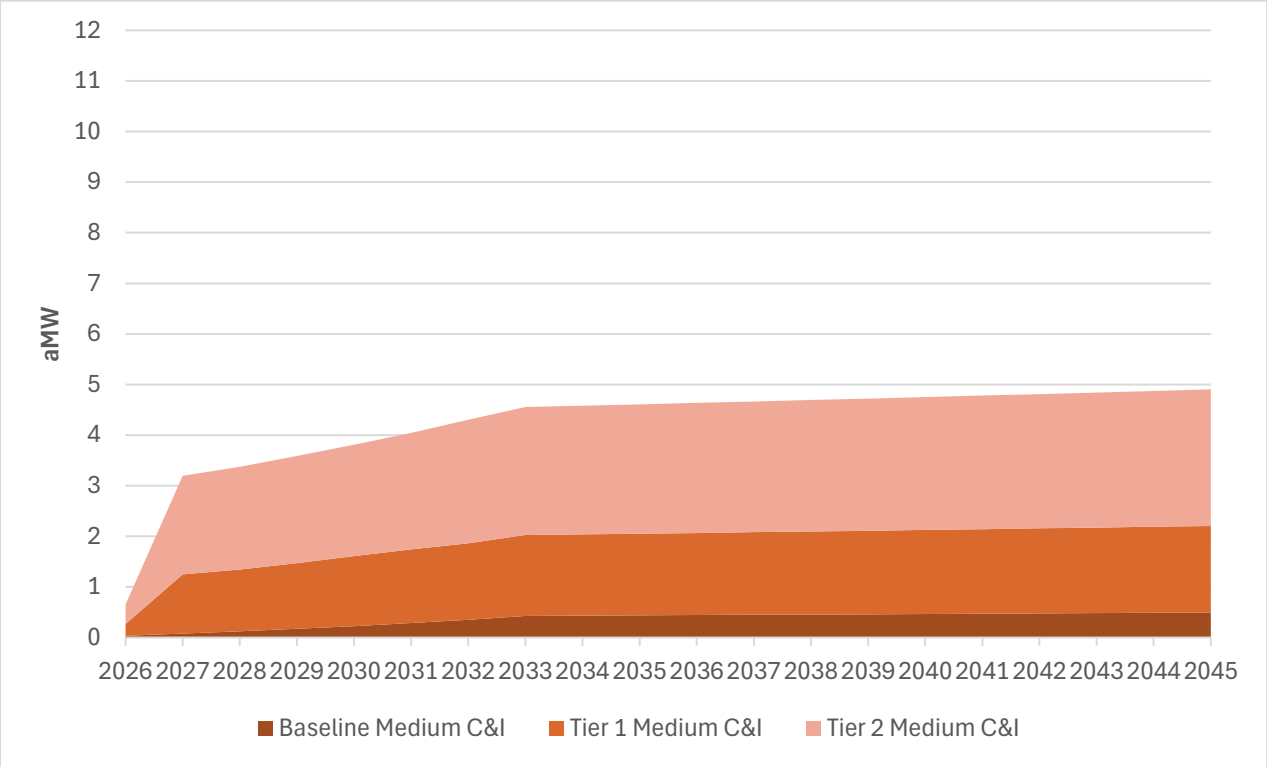


Figure 5-26 Medium Commercial and Industrial Solar Potential by Incentive Level



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

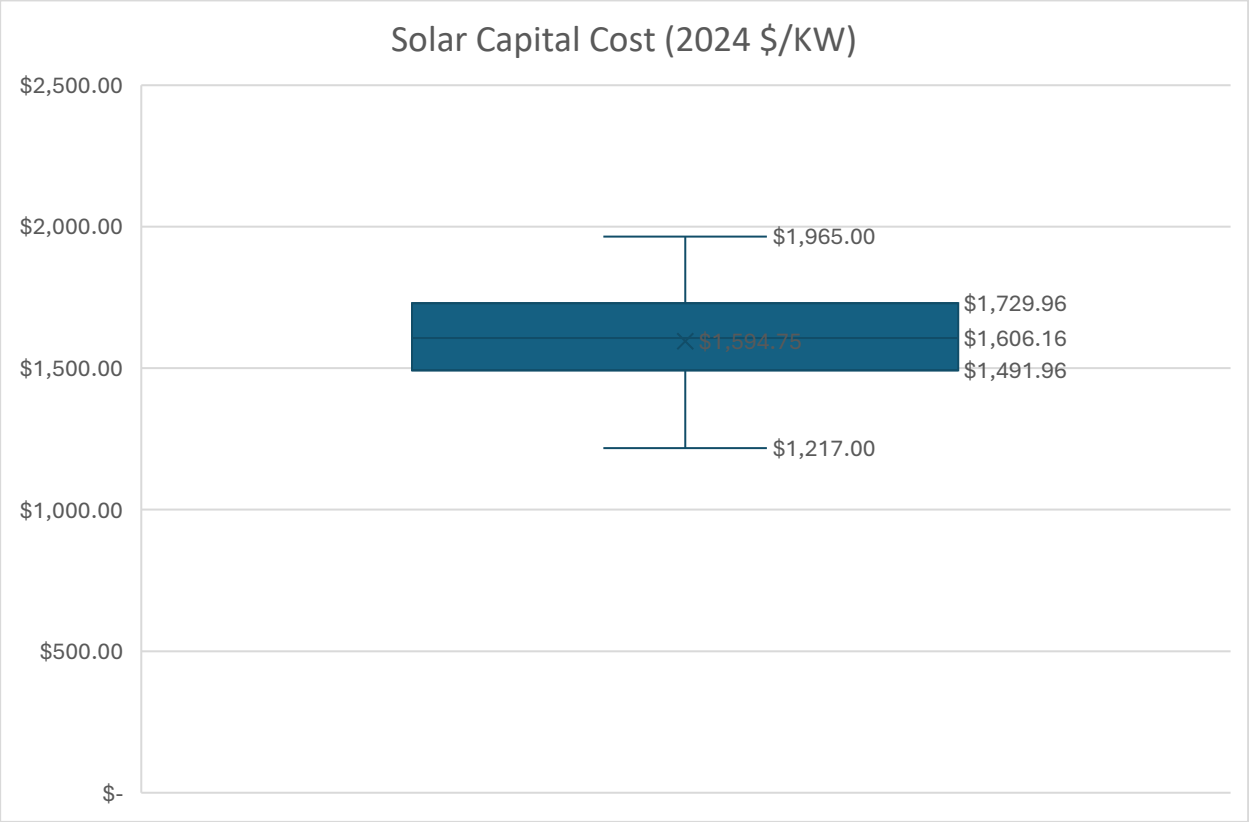
Resource Type	Storage Duration	Nameplate MW	Units Available	First Year Available
Biodiesel Peaker	*	50	1	2026
Lithium-Ion Battery	4 Hr.	25	8	2029
Iron Air Battery	100 Hr.	25	1	2032
300MW Pumped Hydro Storage	8 Hr.	300	1	2035
150MW Pumped Hydro Storage	10.66 Hr.	150	1	2035
Simple Cycle Natural Gas Peaker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

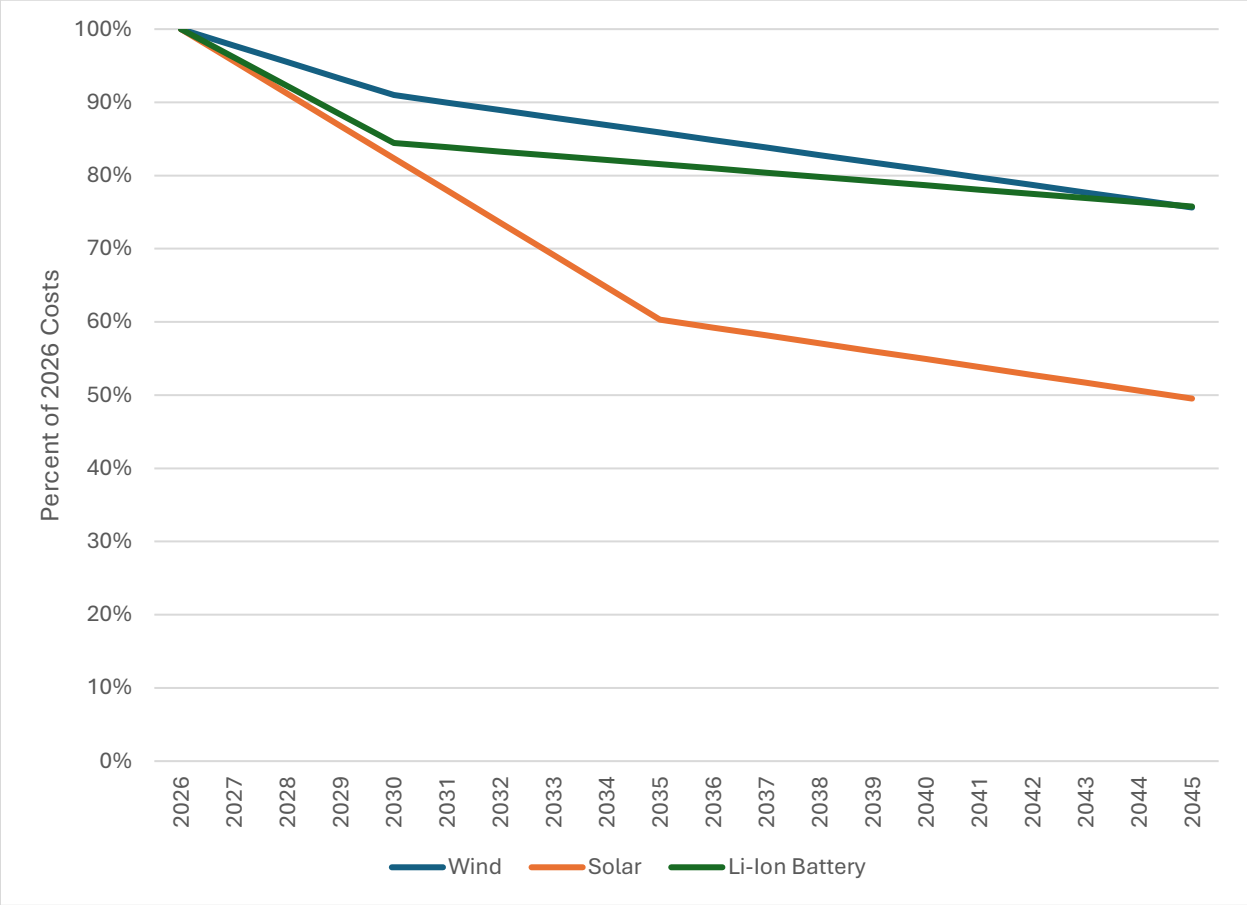
shows an example of how a composite cost was derived for the Overnight Cost of Capital (development cost estimate) for utility-scale solar plants.

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-

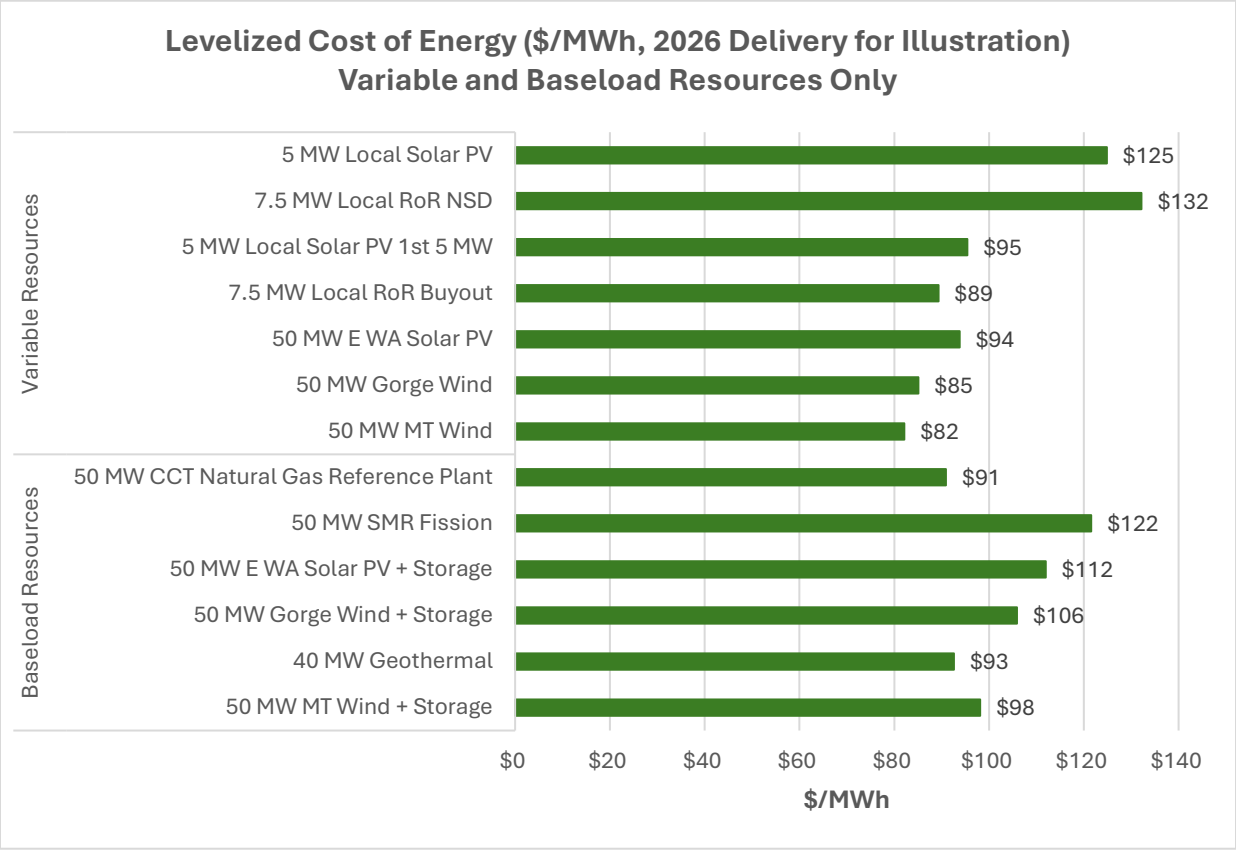
[15] Regional Dialogue Guidebook: Background on Products, Rates, and Resource Support Services available to BPA's Public Utilities

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.

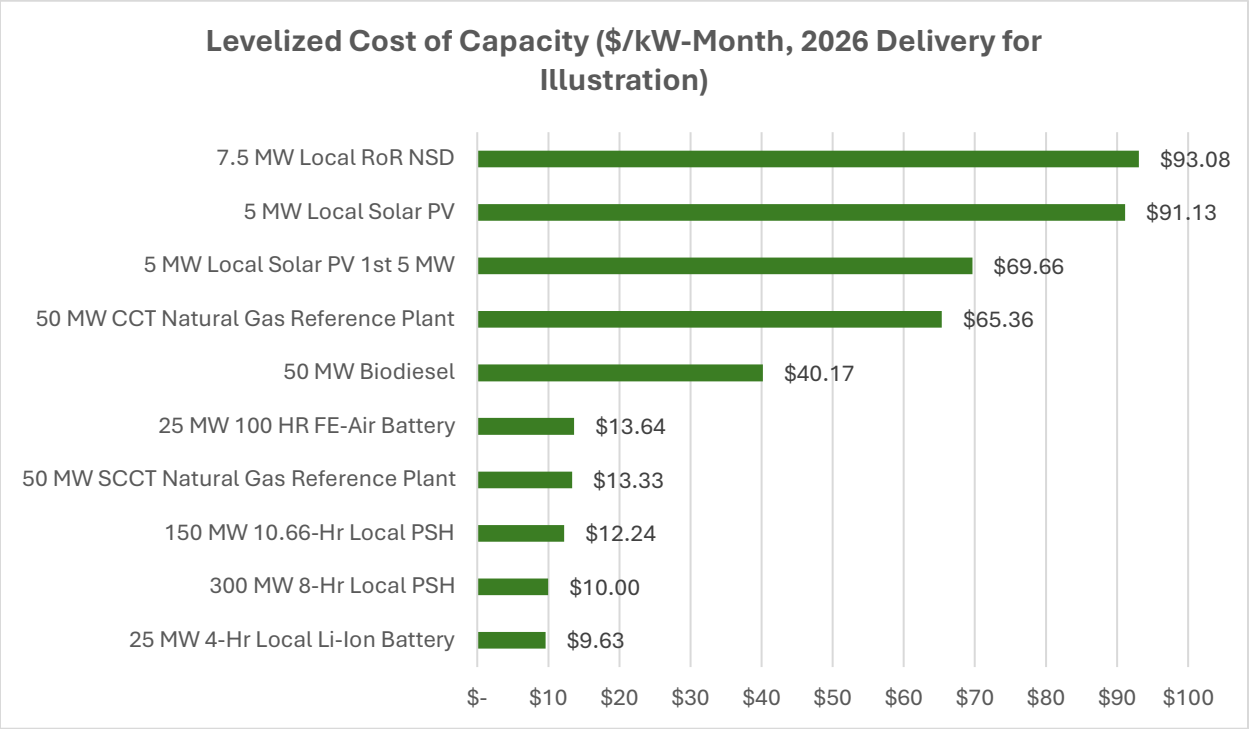
Figure 5-29 Levelized Cost of Energy, 2026 Delivery



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

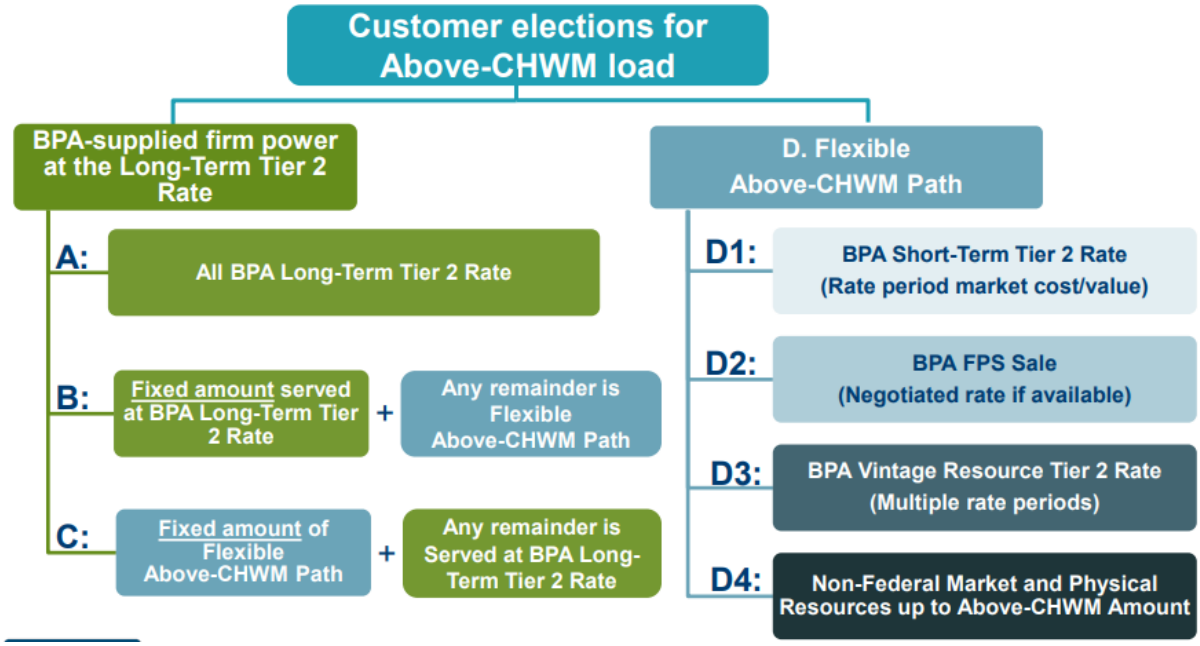
includes significant market purchases and solar procurement in the later period. The IRP models long-term Tier 2 as always starting with 100% market purchased energy and layering in solar until it is a 50/50 mix of market energy and solar for the base case market environment. Market price expectations 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

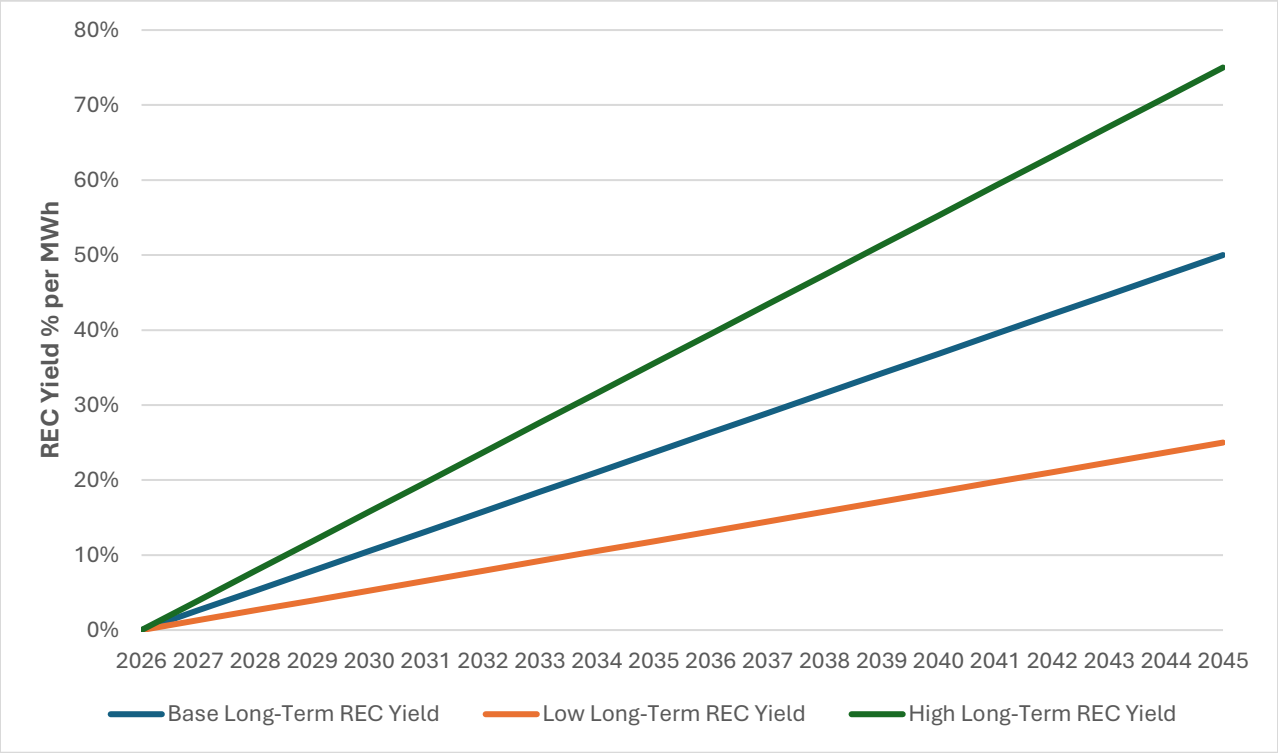
The IRP considers Tier 2 for its regulatory compliance and cost characteristics compared to other supply- or demand-side resources. These costs are shown for both long-term and short-term Tier 2 products below. The assumptions of long-term environmental attributes are described above and are not considered 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,

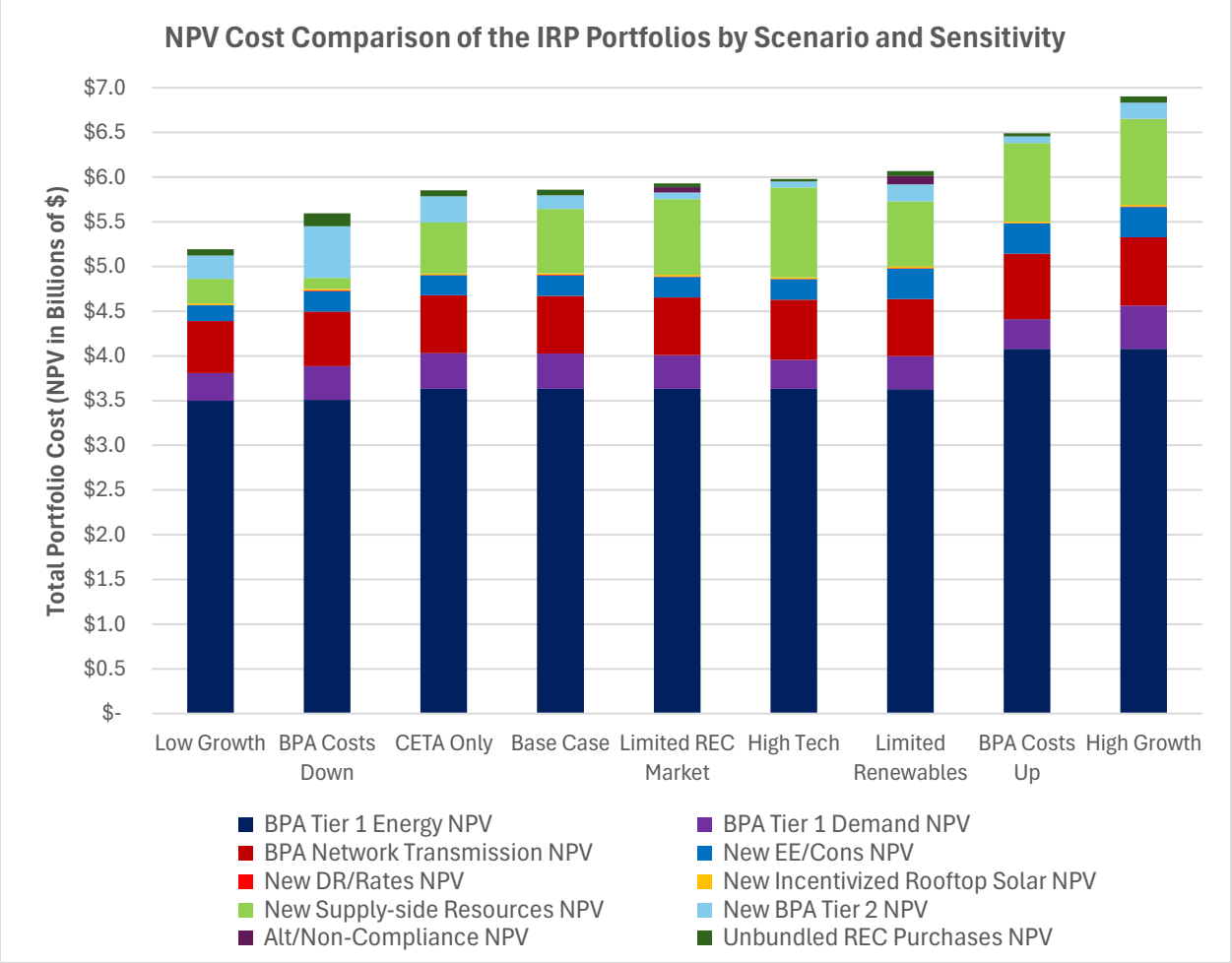
[16] Referenced requirements are detailed in the Revised Code of Washington, Section 19.280.030.

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

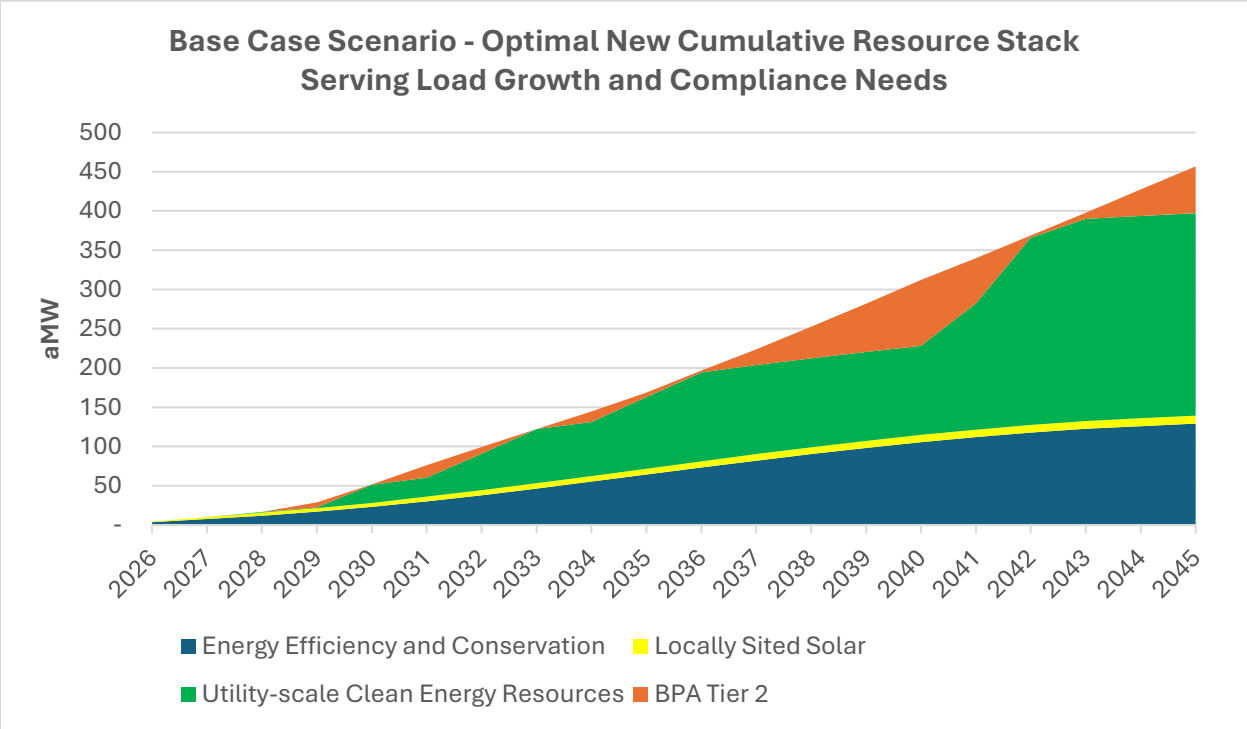
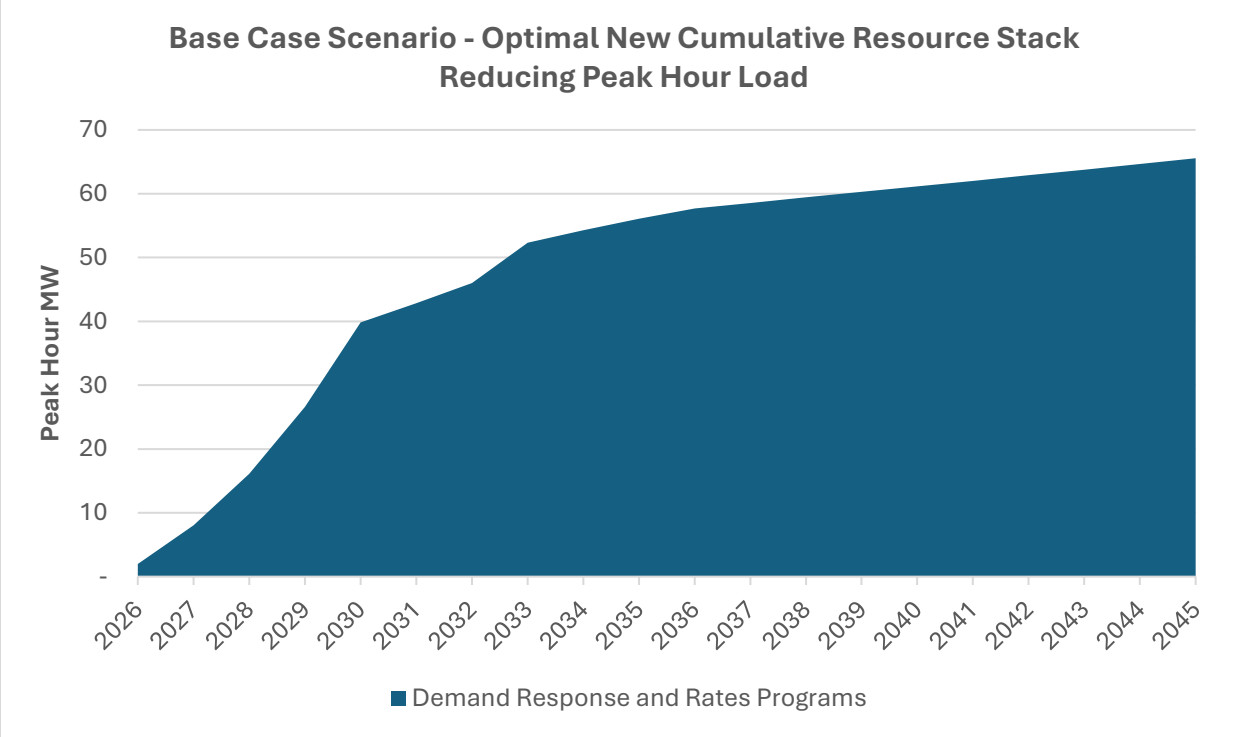


Figure 6-3 Base Case Peak Demand Resource Additions



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

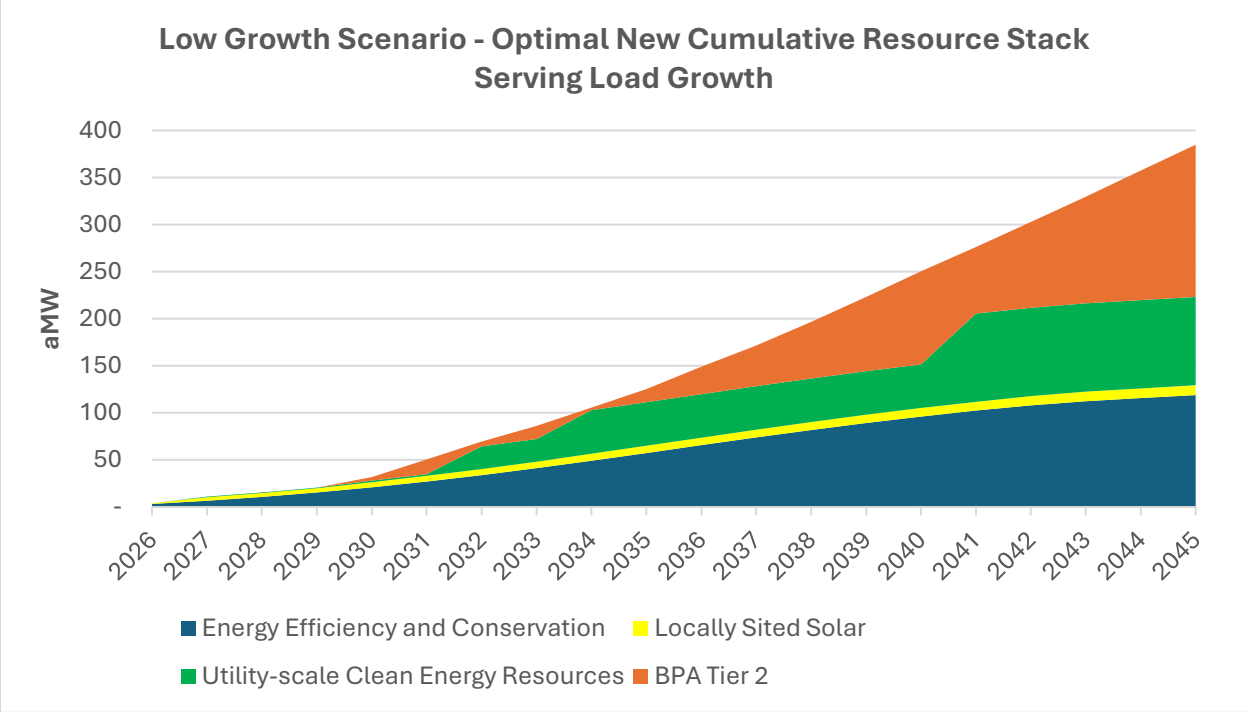
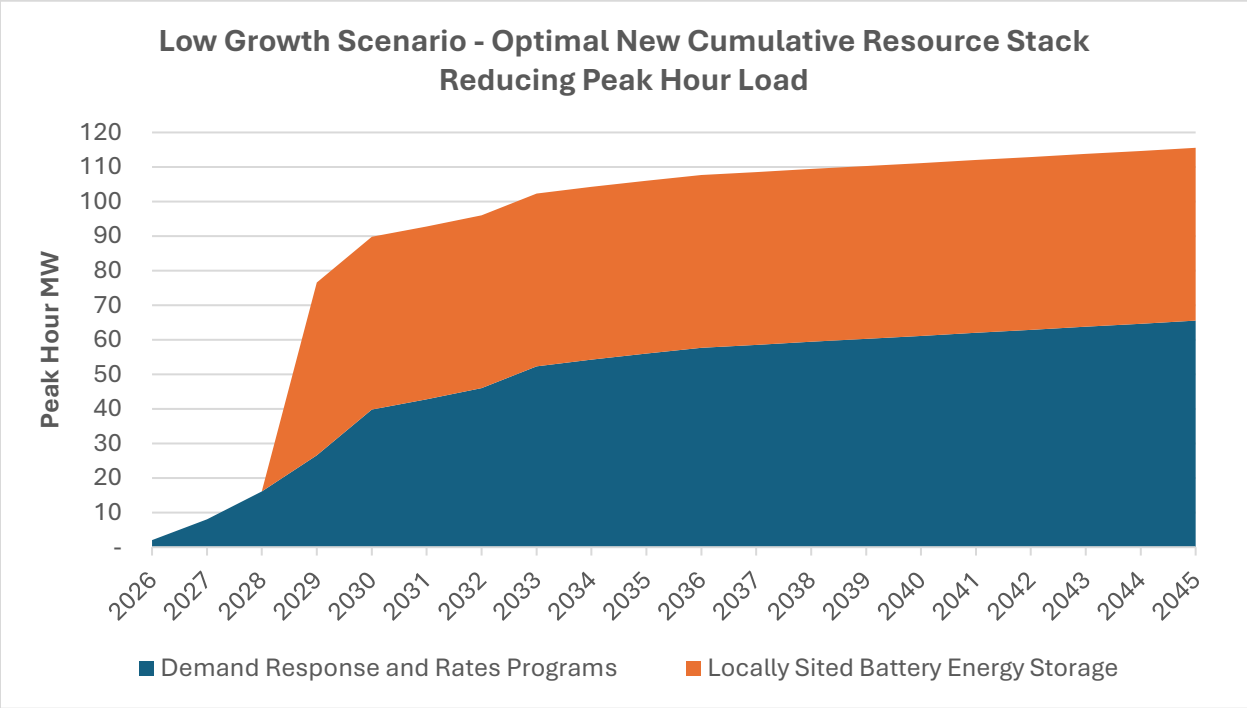


Figure 6-5 Low Growth Case Peak Demand Resource Additions



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

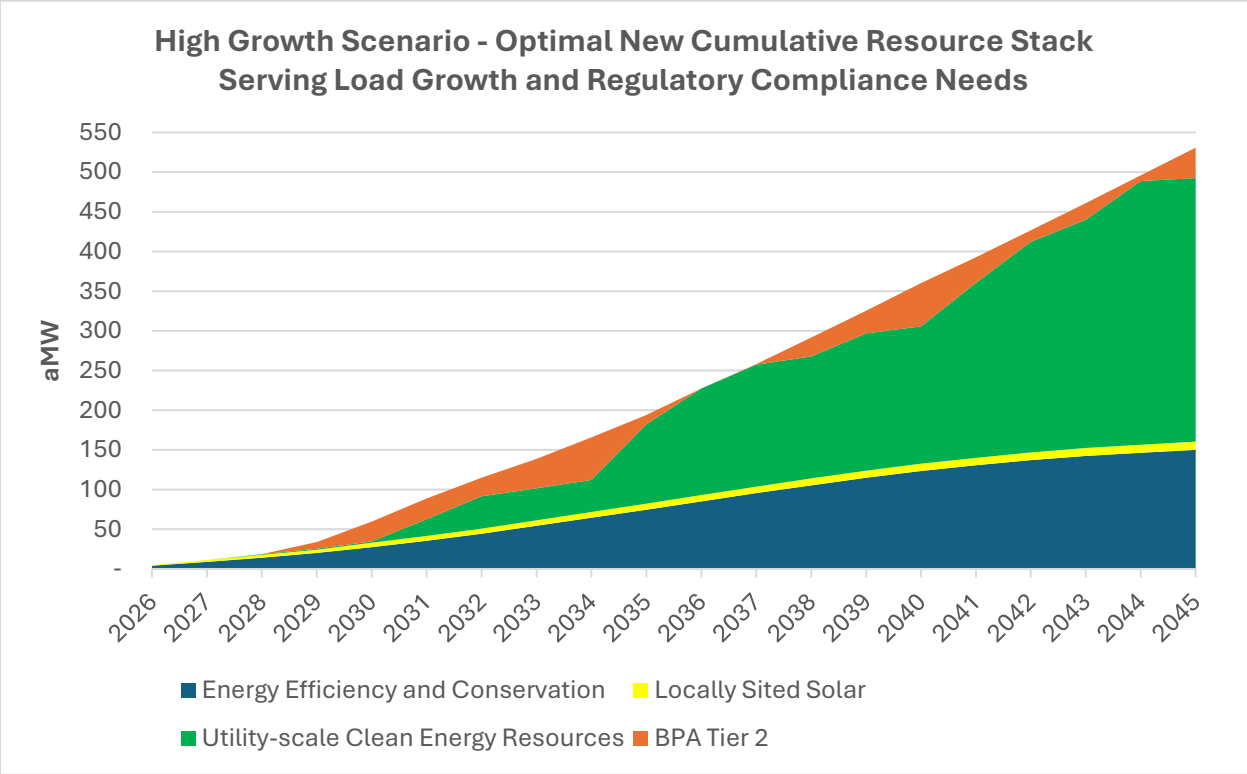
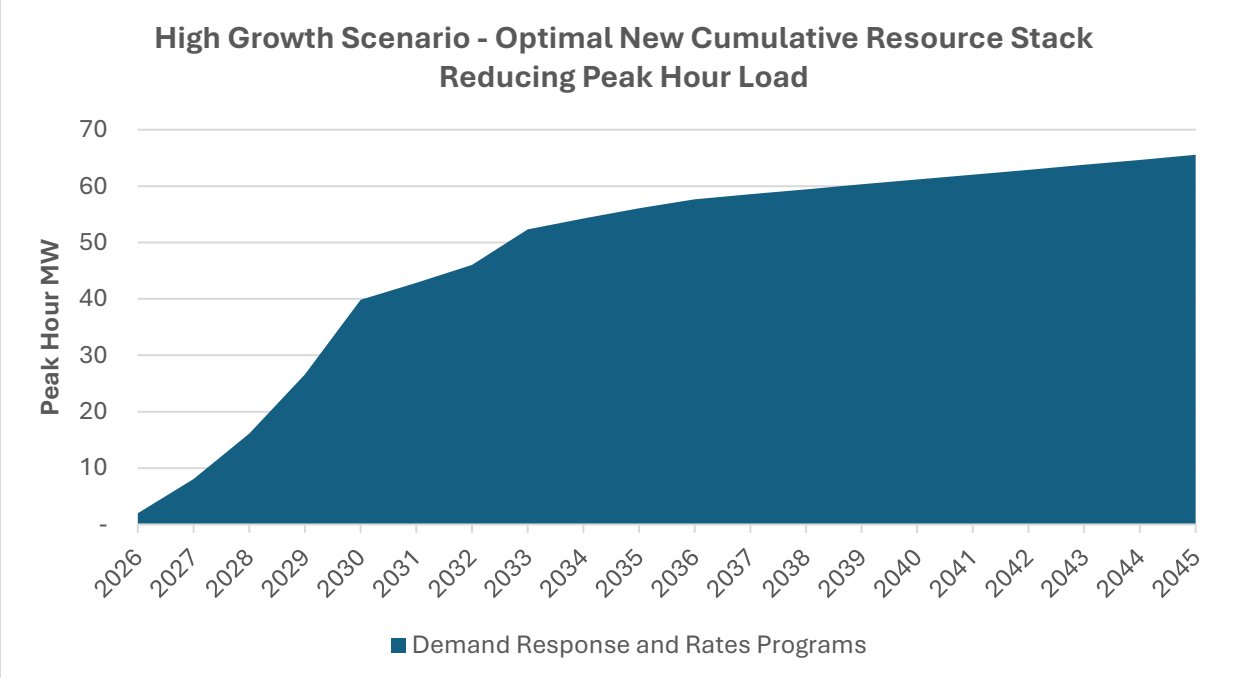


Figure 6-7 High Growth Case Peak Demand Resource Additions



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

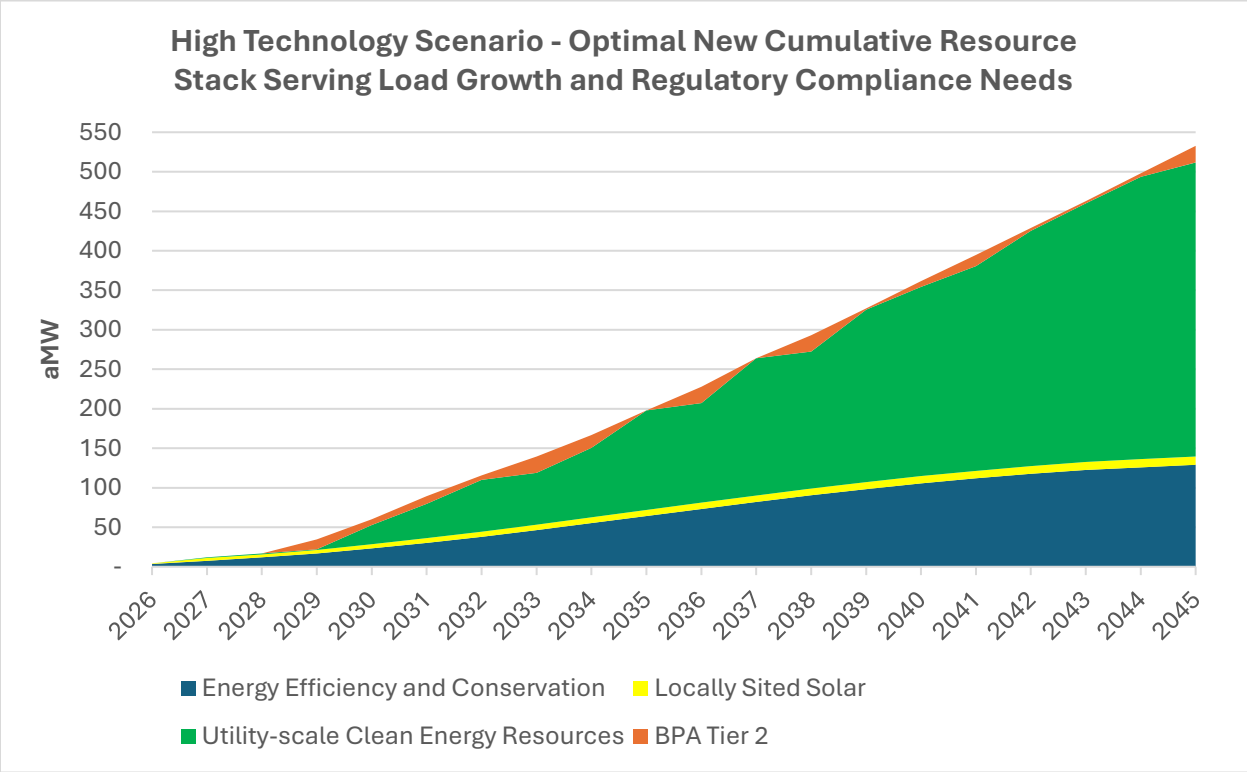
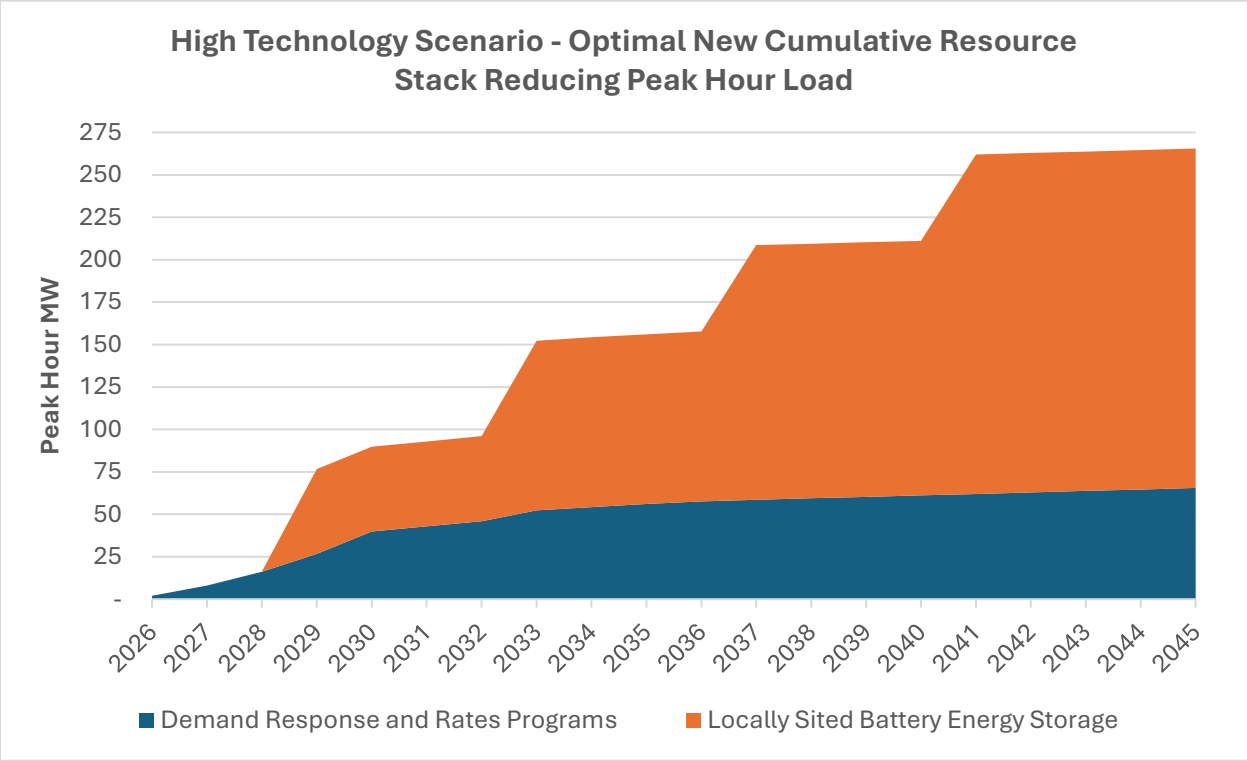


Figure 6-9 High Technology Case Peak Demand Resource Additions



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

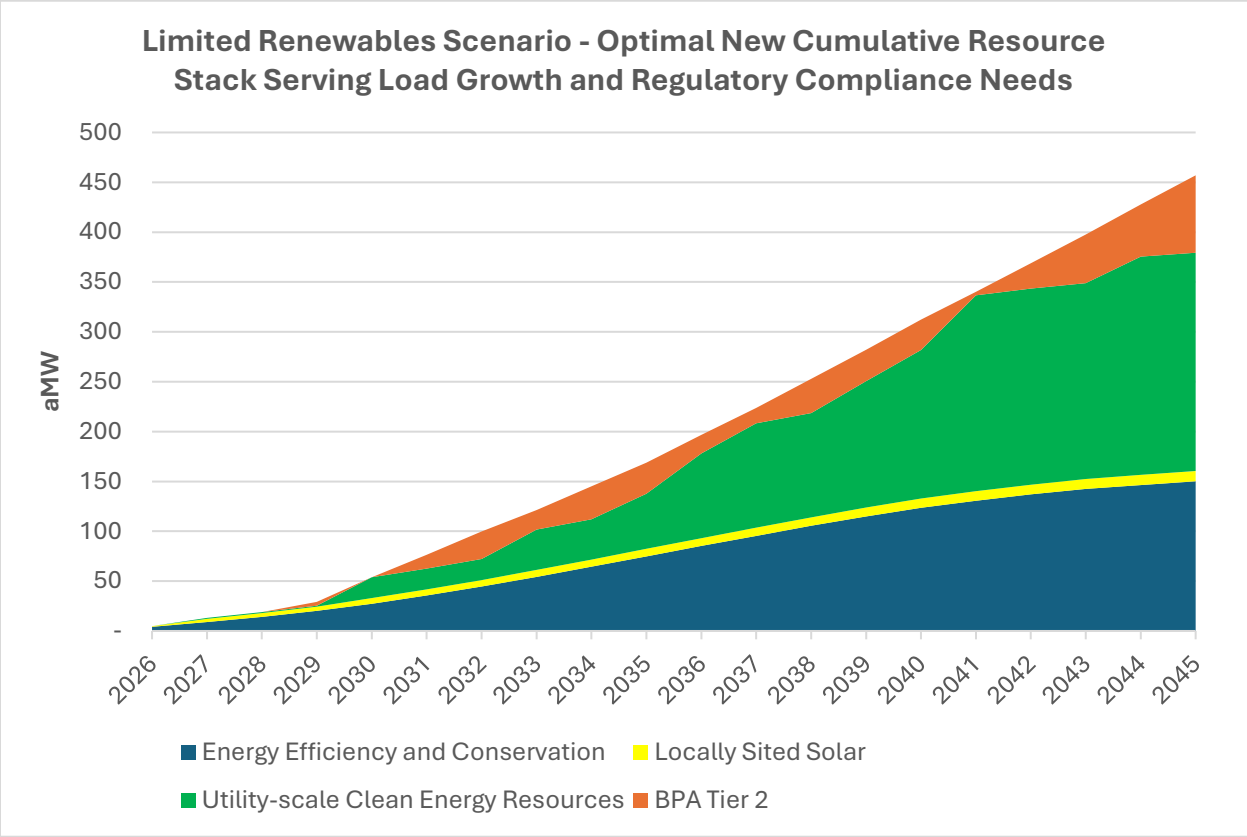
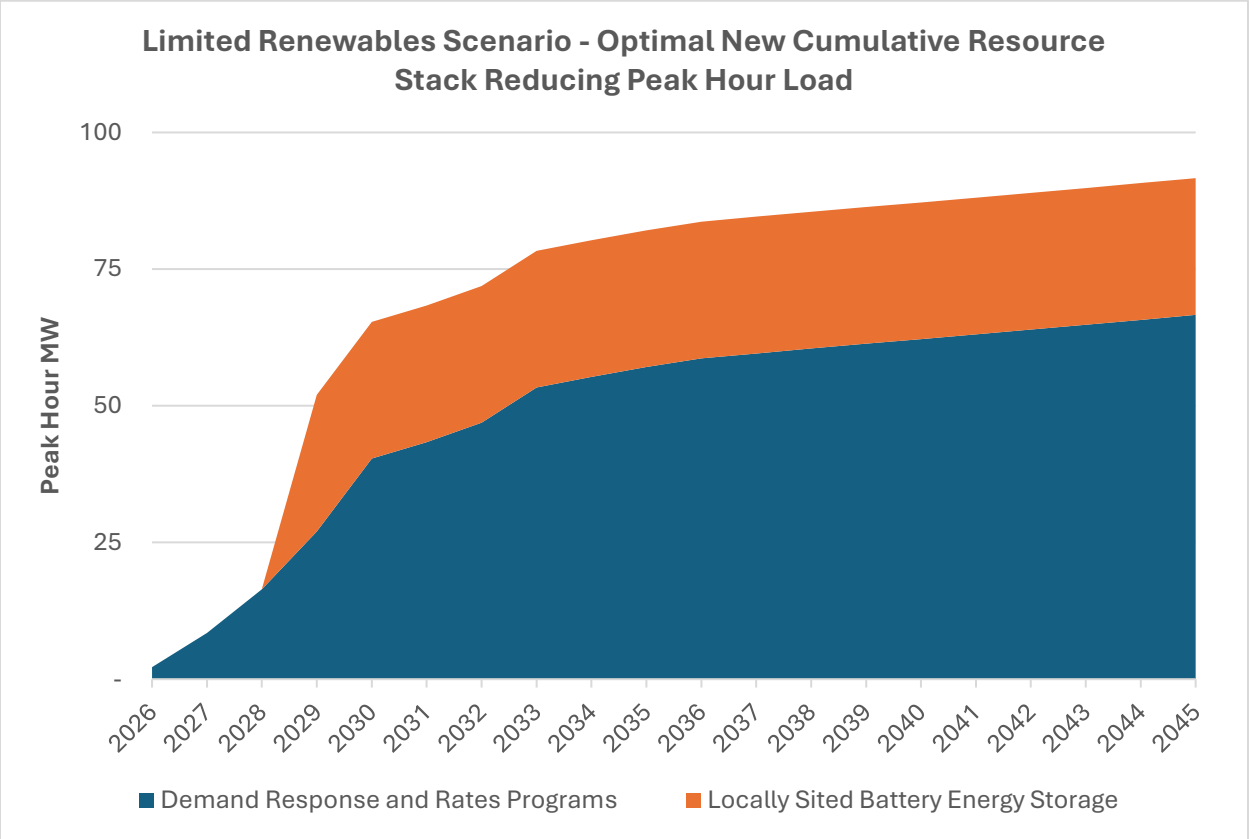


Figure 6-11 Limited Renewables Case Peak Demand Resource Additions



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

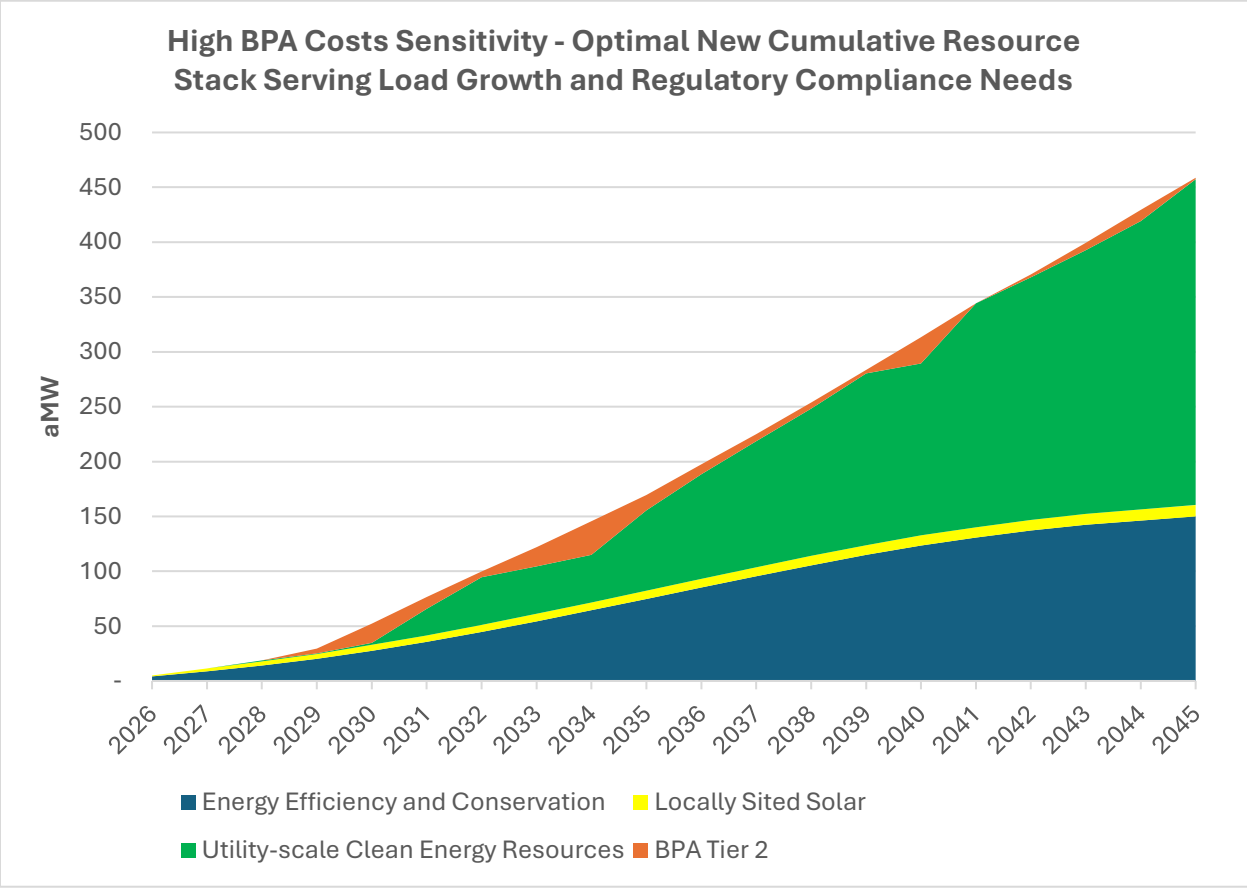
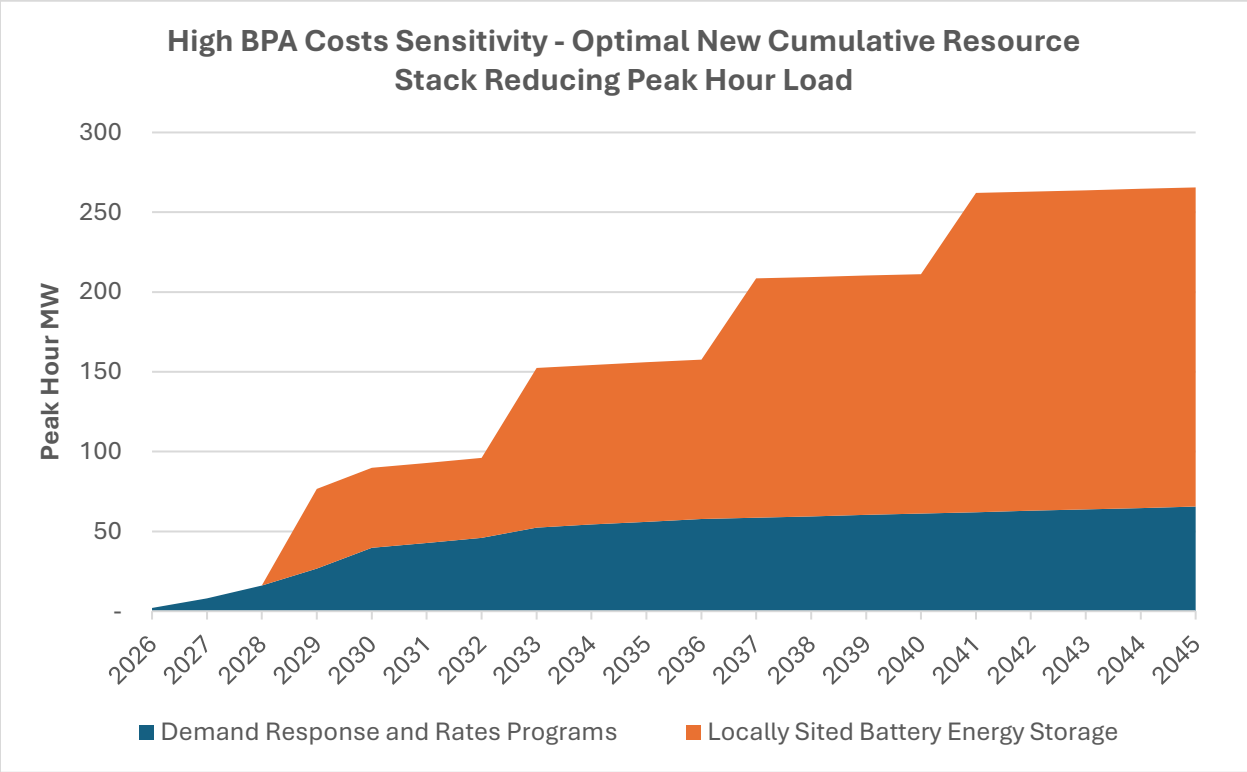


Figure 6-13 High BPA Cost Case Peak Demand Resource Additions



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

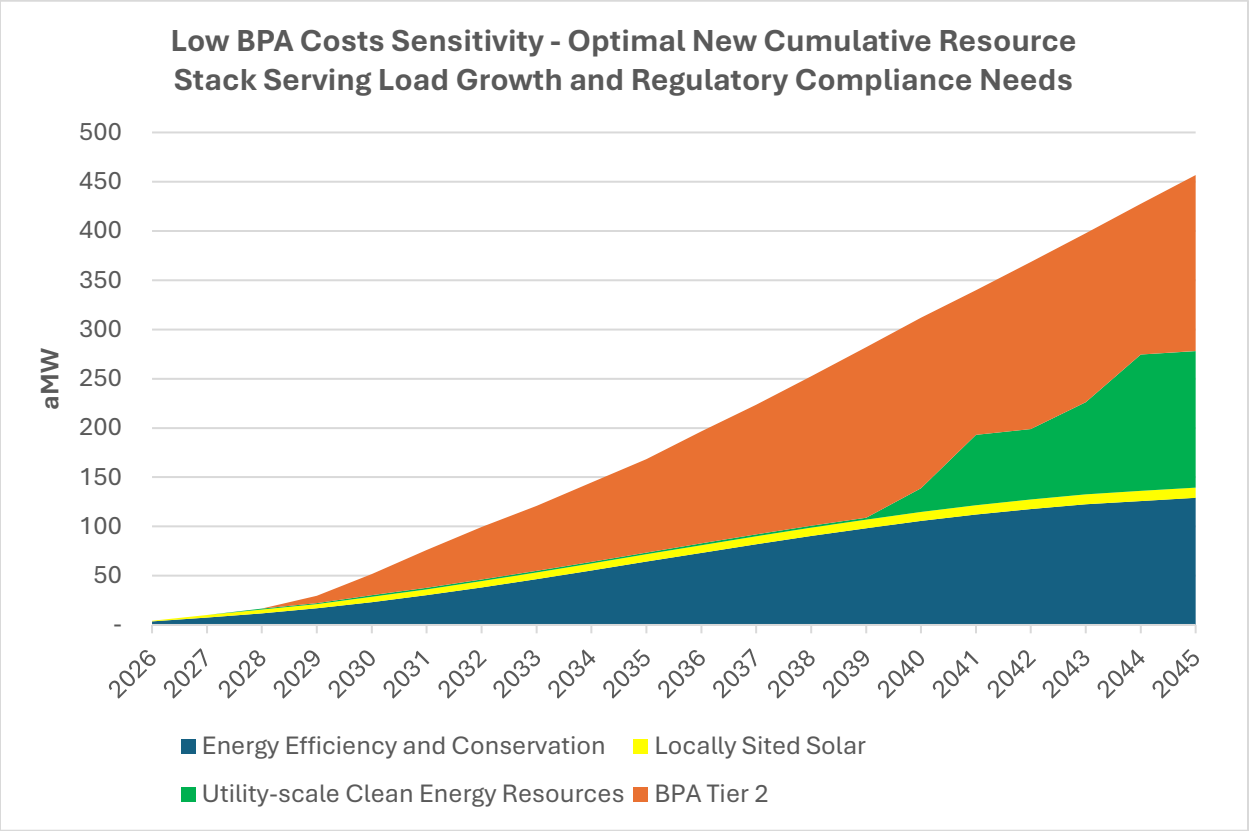
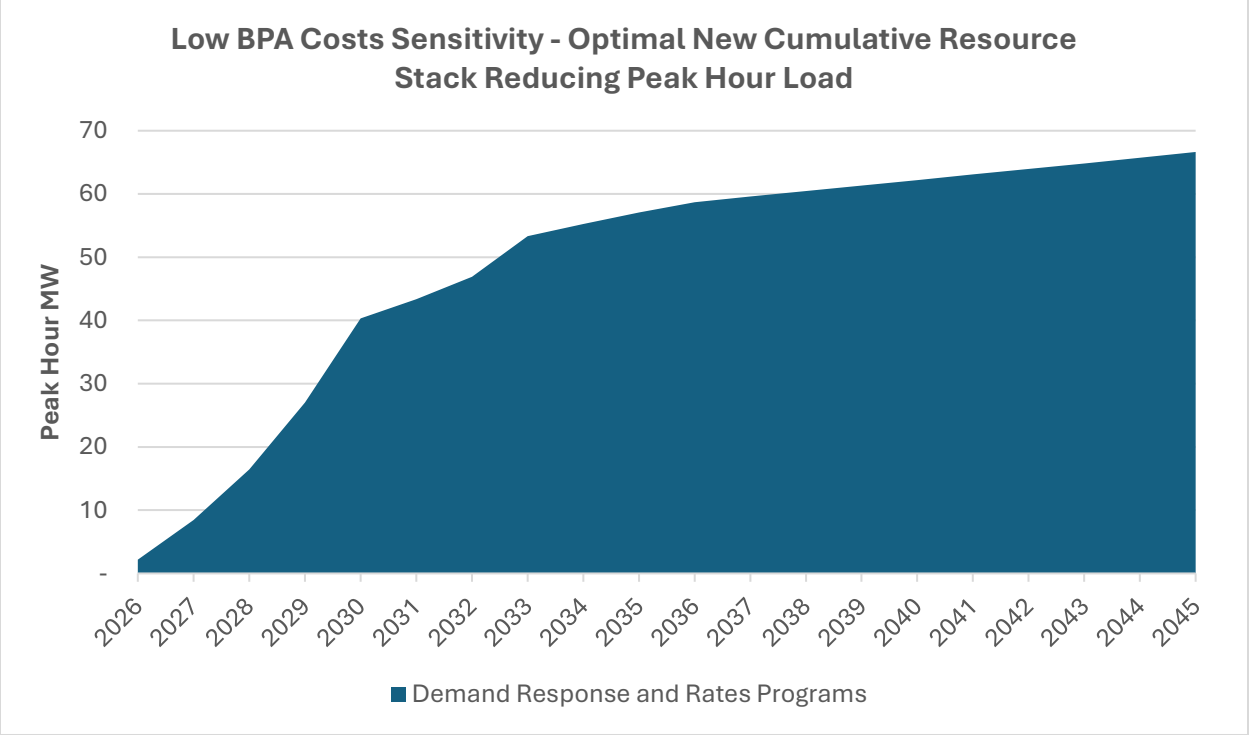


Figure 6-15 Low BPA Cost Case Peak Demand Resource Additions



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

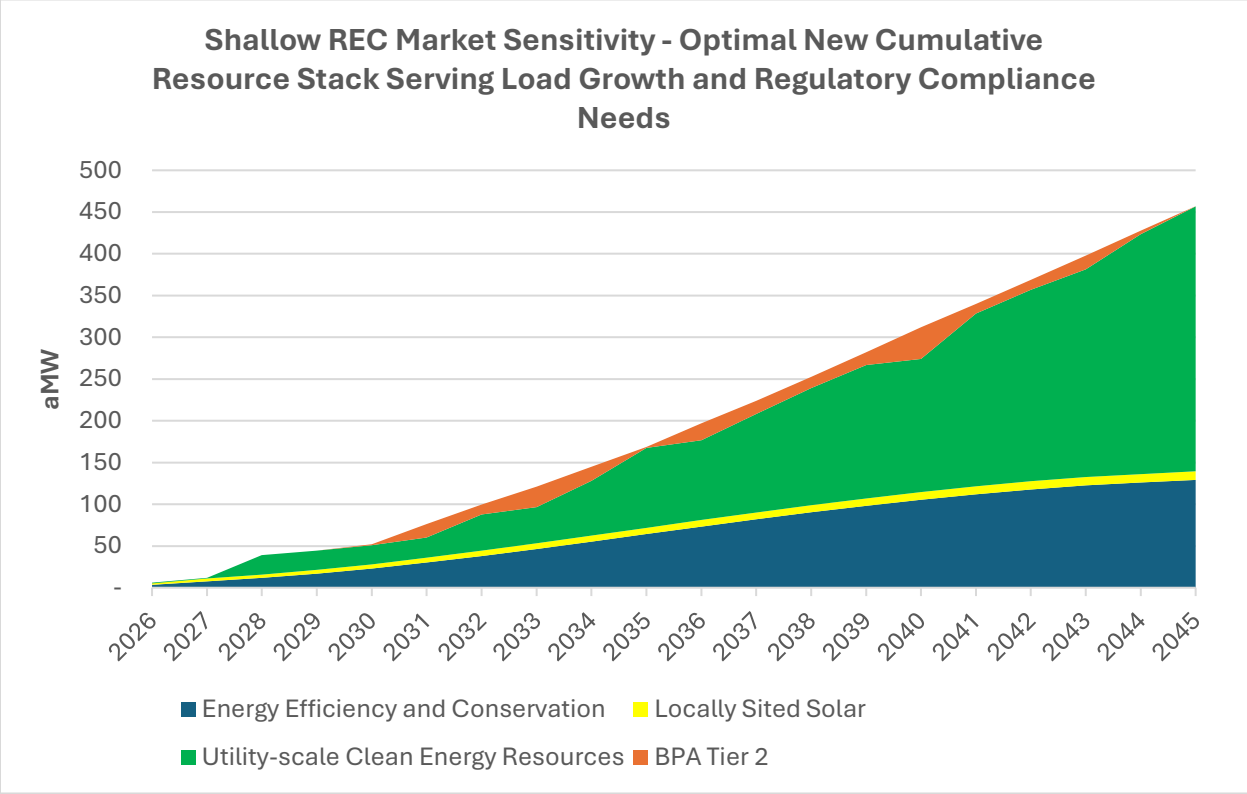
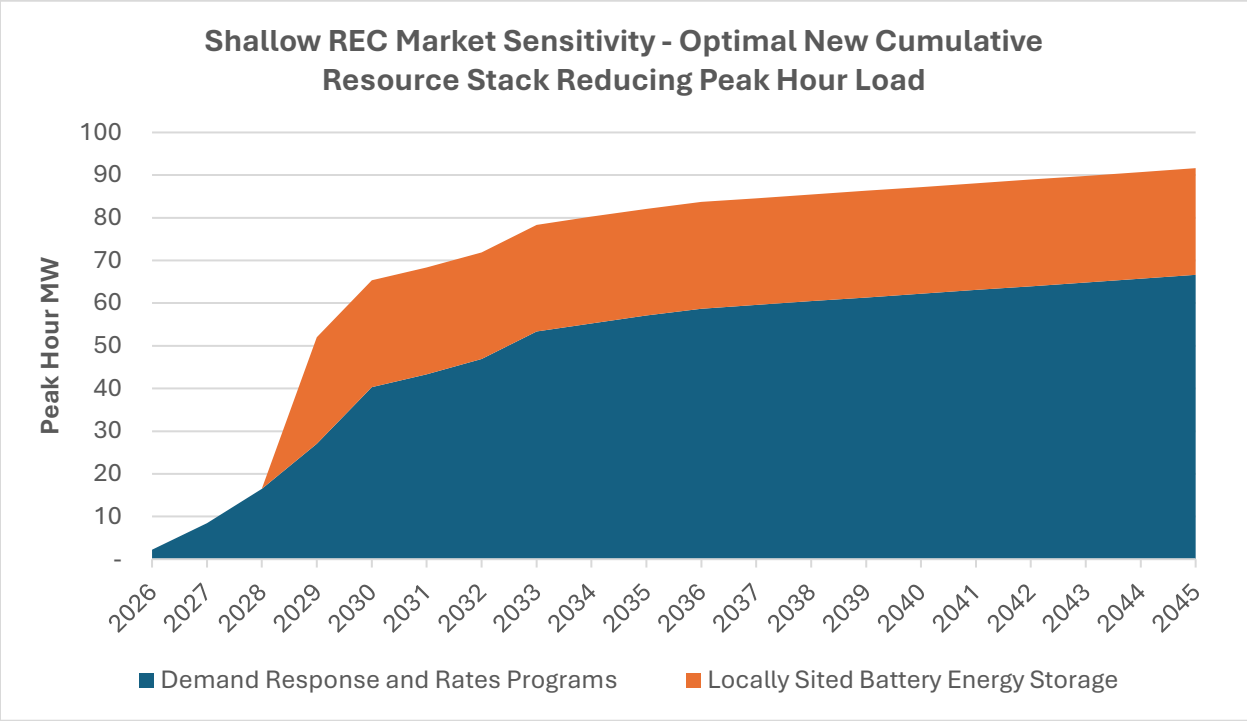


Figure 6-17 Shallow REC Market Case Peak Demand Resource Additions



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

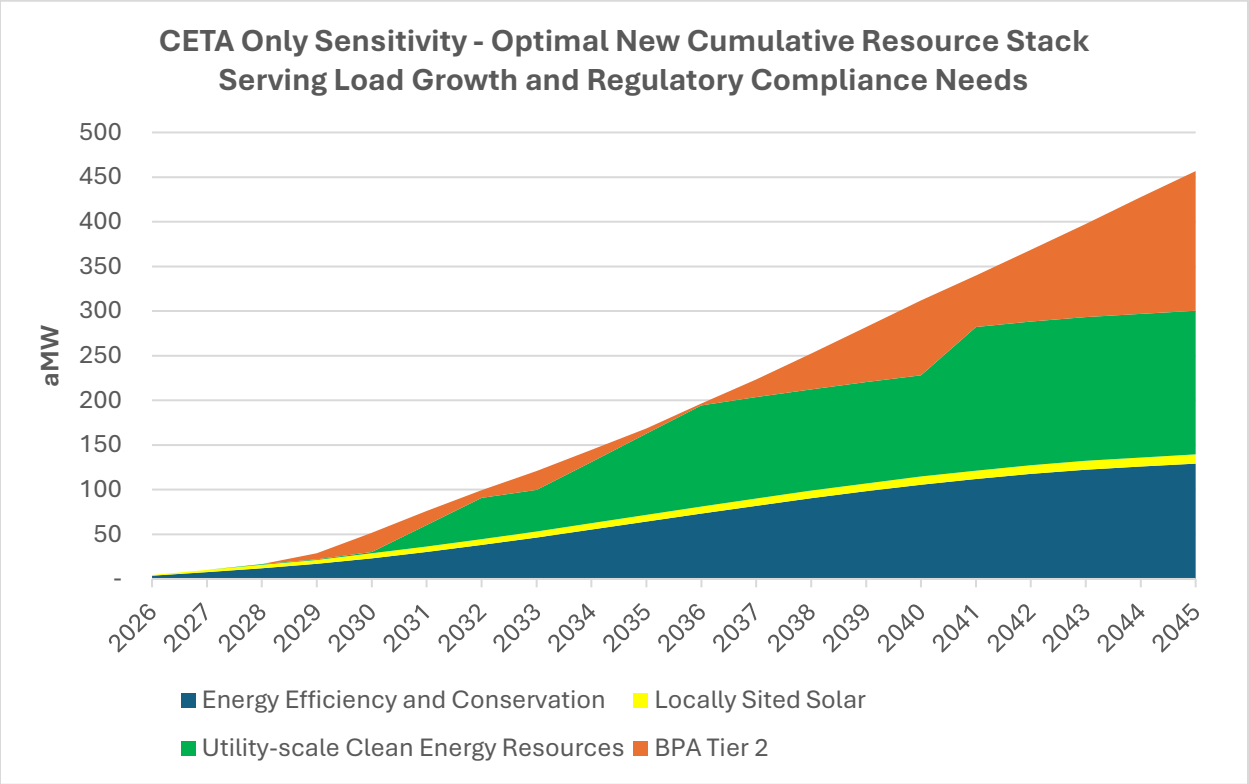
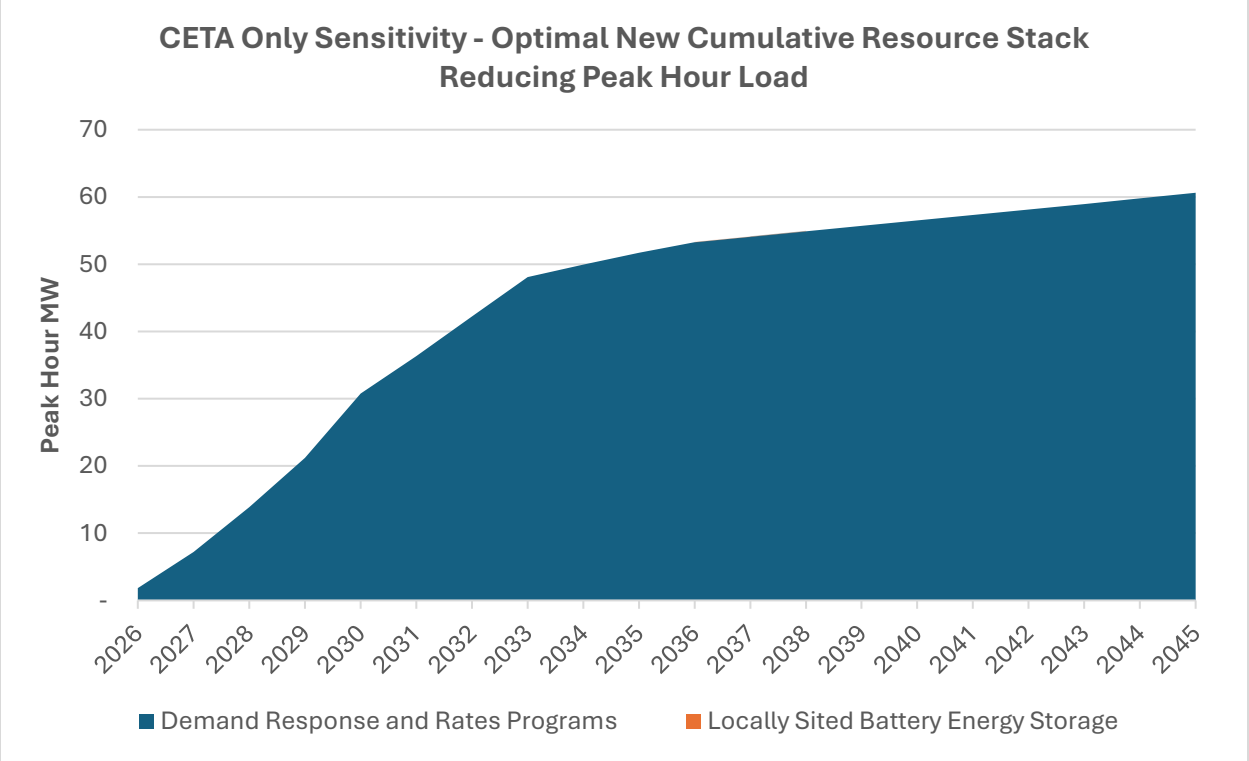


Figure 6-19 CETA Only Case Peak Demand Resource Additions



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.

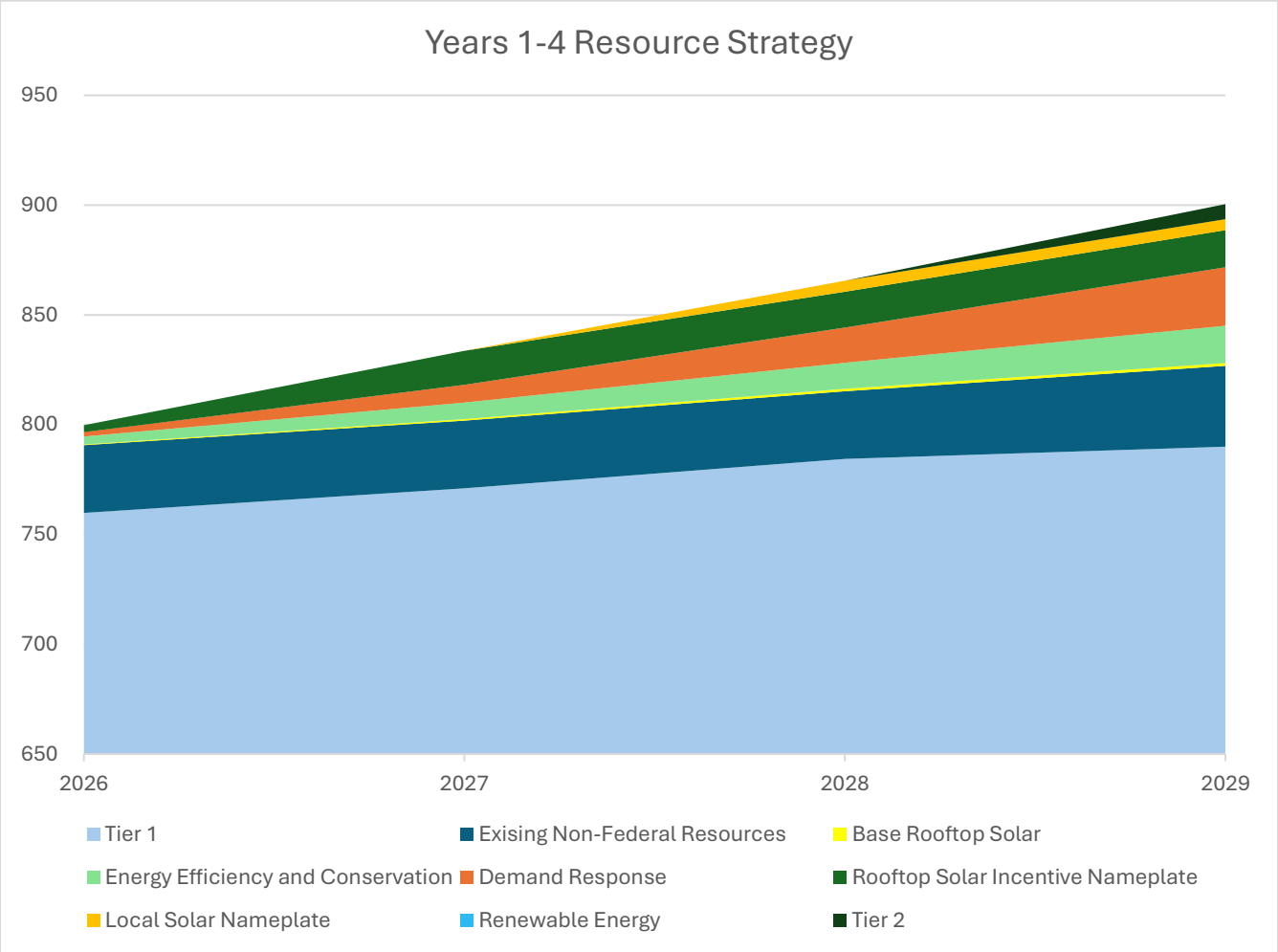
Resource Strategy Details

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

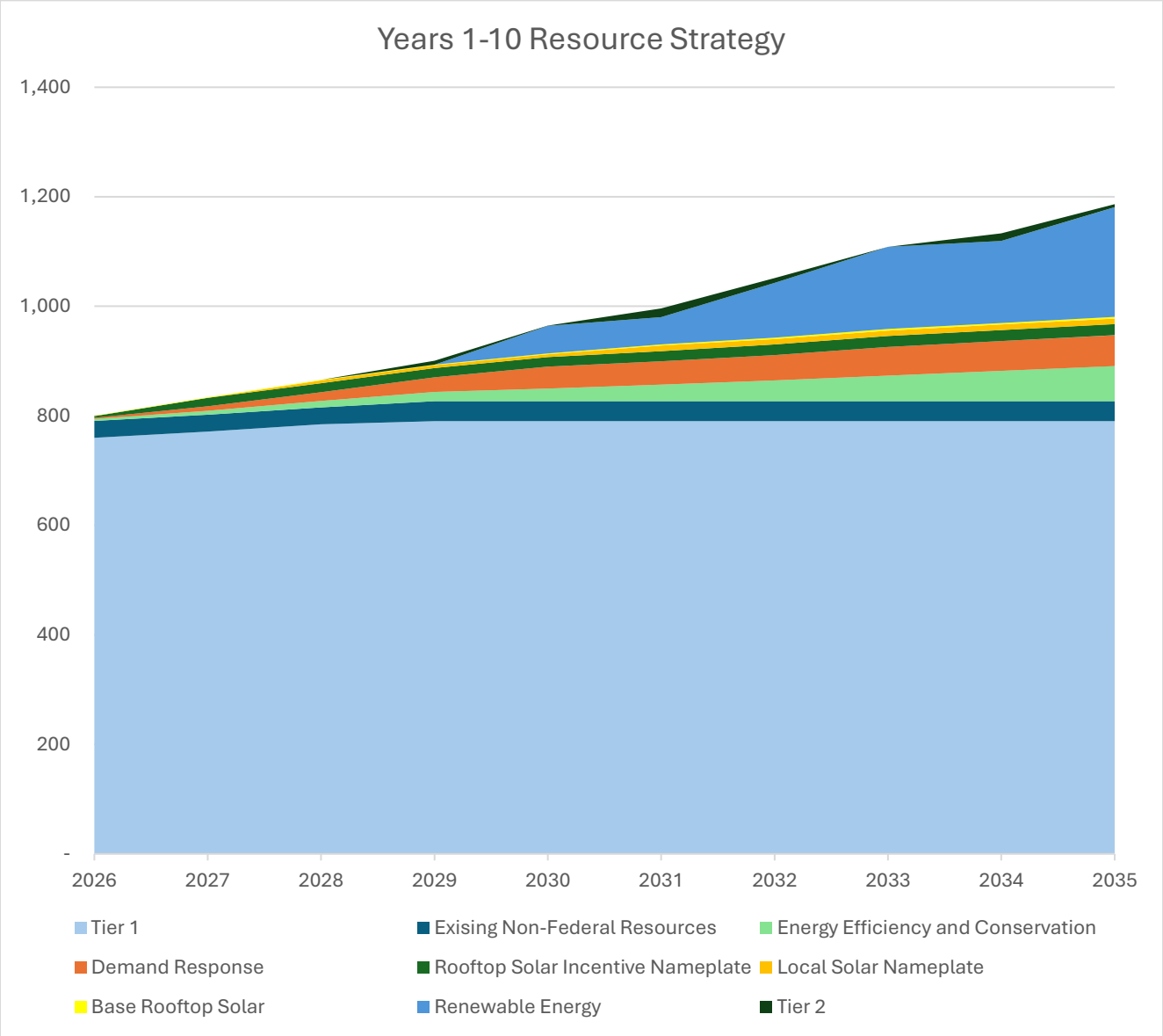


Intermediate Term Resource Strategy Details

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

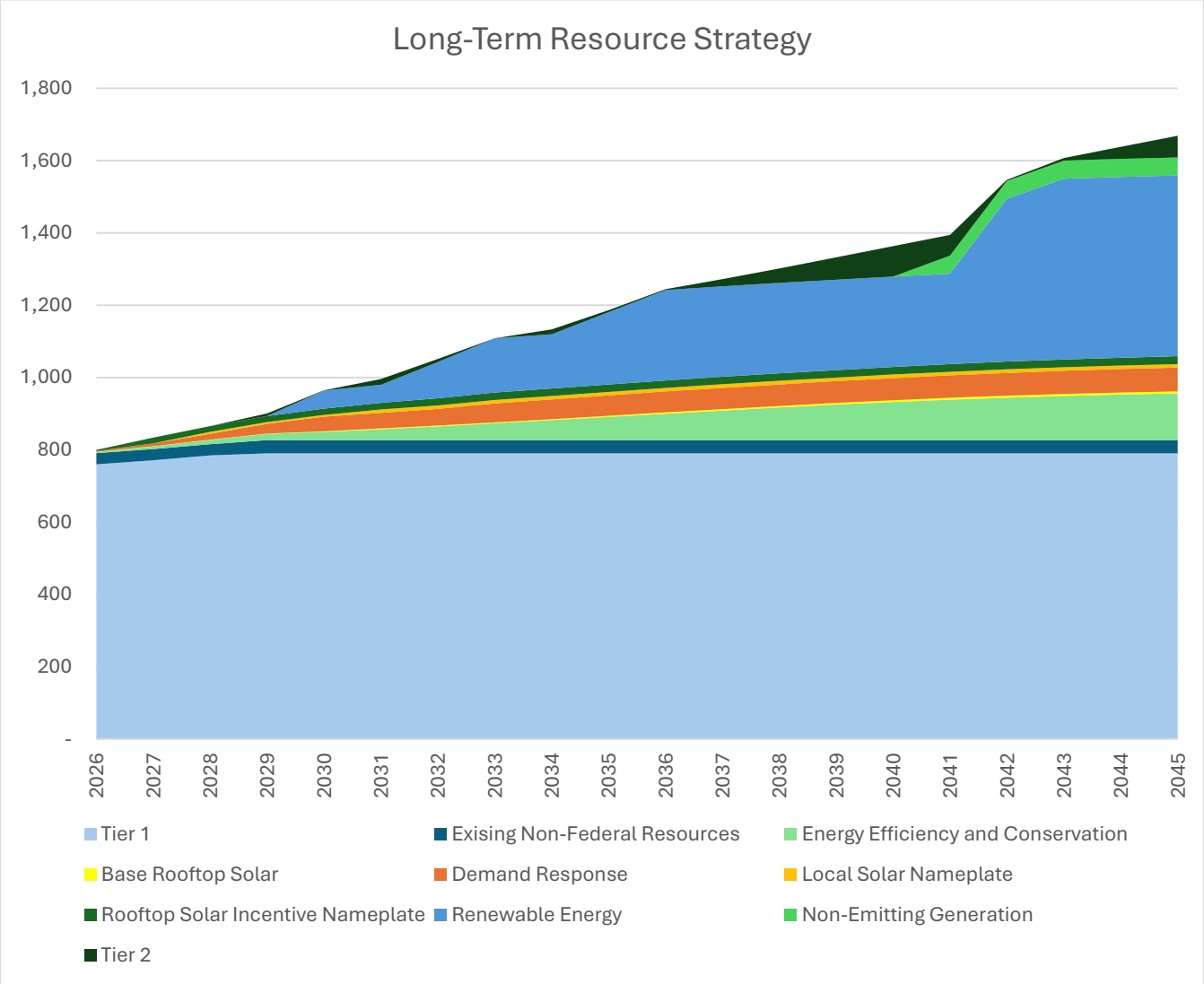


Total Resource Strategy

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):

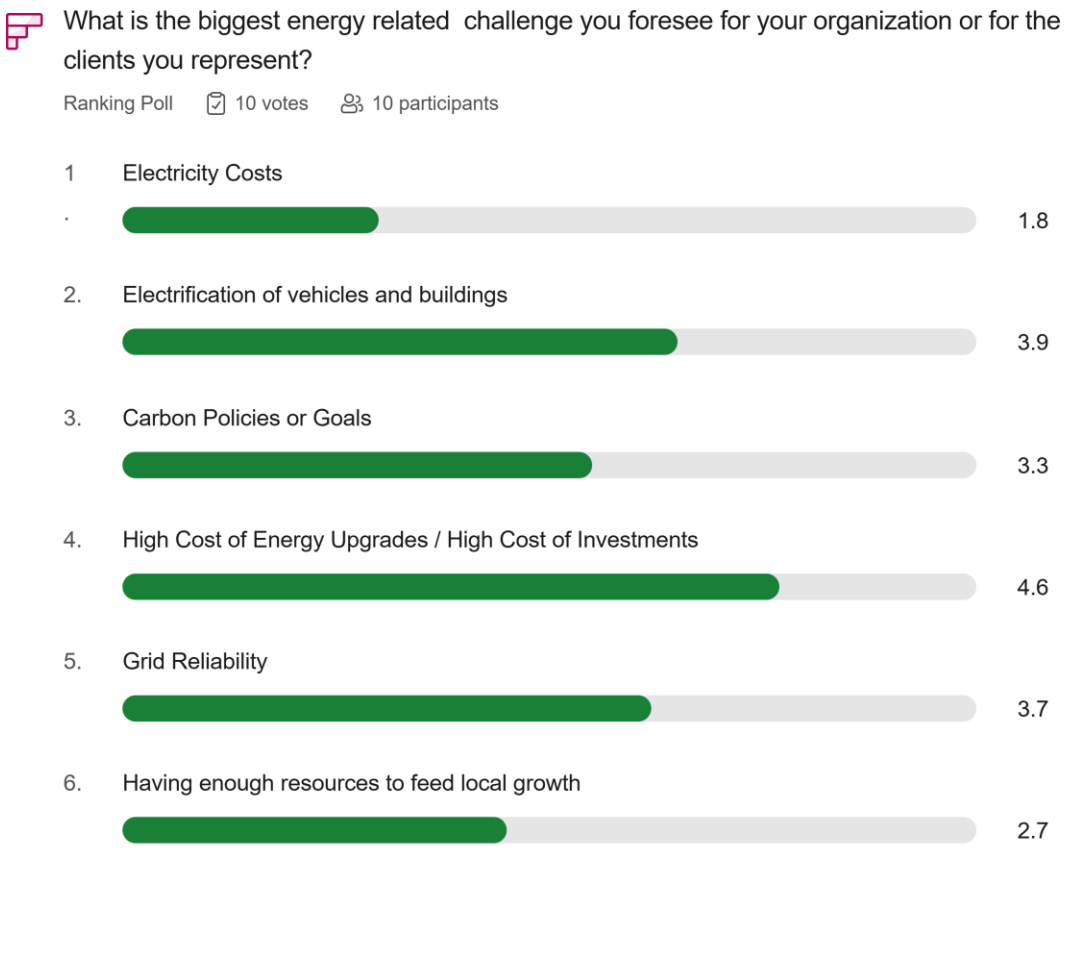
- Fleet electrification is probable in the PUD's service territory. Several individuals mentioned their organizations were exploring potential to change their fleets to electric vehicles outside of the traditional goods transportation sectors.
- Residential adoption of electric vehicles for energy burdened 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

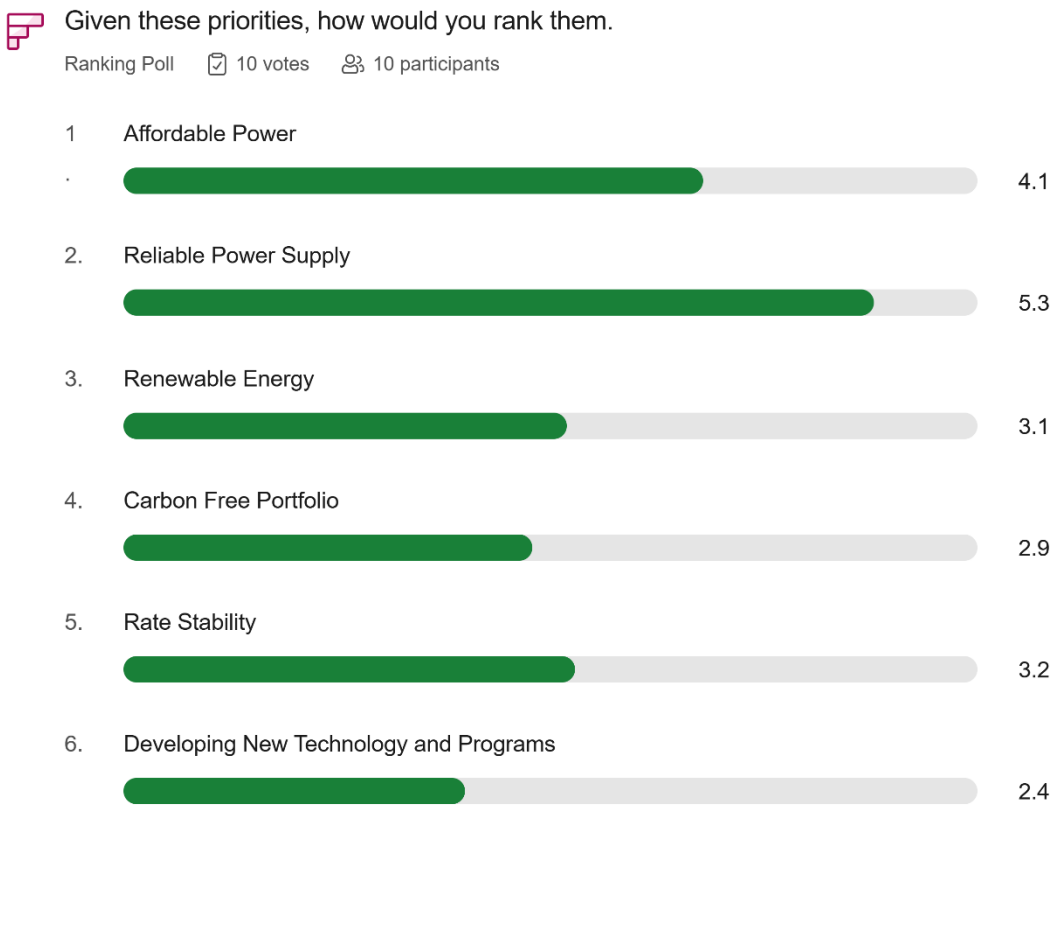


Figure C - 2 Largest Challenge for the Energy Future



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.

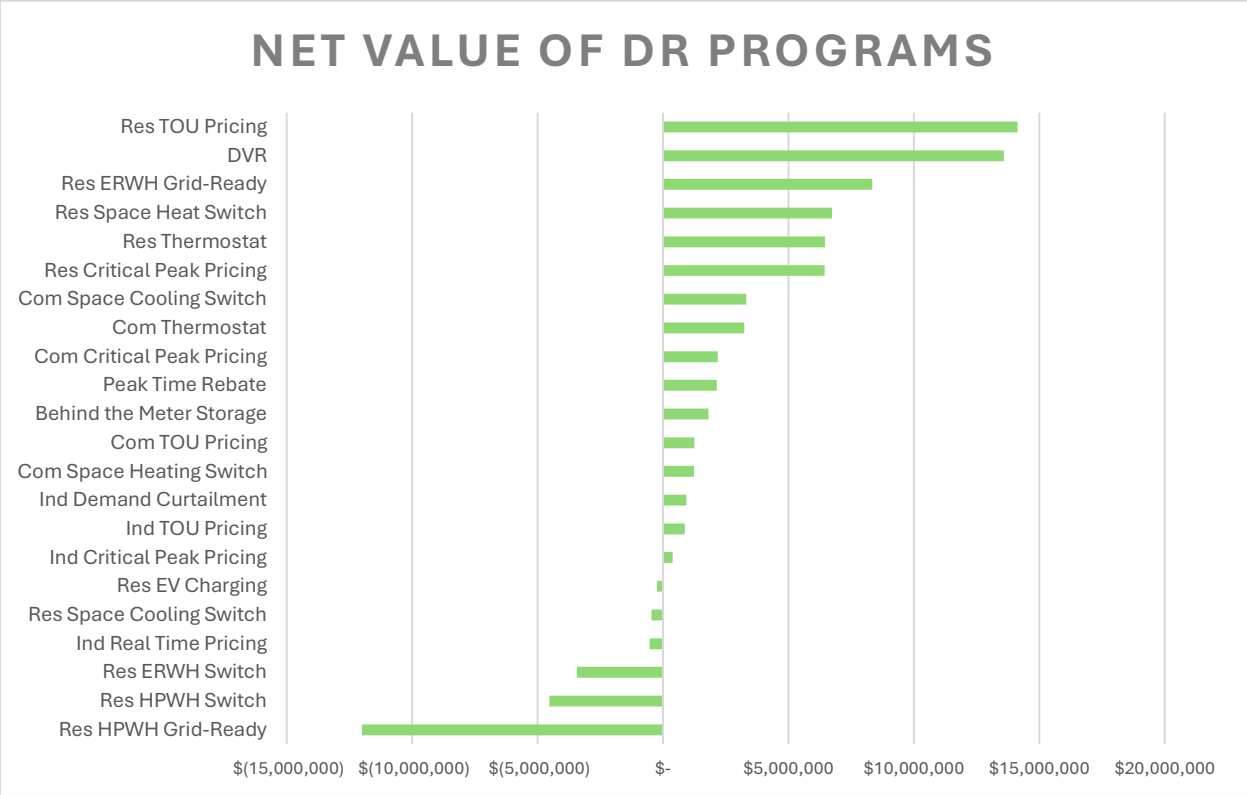
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Appendix E. Demand Response Value Analysis

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.

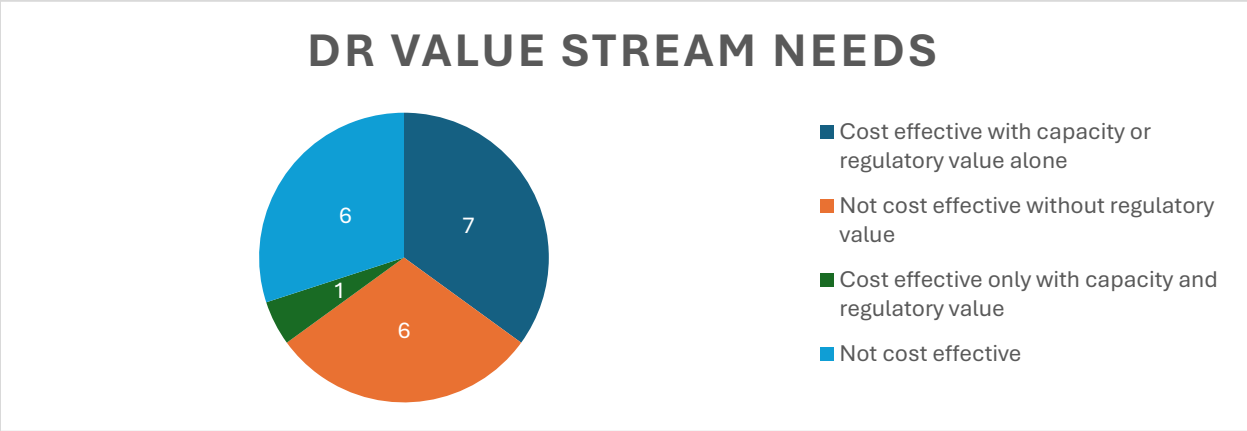
The amount of regulatory value received through the DR is dependent on the price of the RECs that would have otherwise been purchased in compliance with the Energy Independence Act. It is also dependent on how DR capacity against peak system load is counted; if the bill uses the maximum capacity of a 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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BUSINESS OF THE COMMISSION

Meeting Date: December 2, 2025 **Agenda Item:** 6B

TITLE

Public Hearing on Proposed 2025 Clean Energy Implementation Plan

SUBMITTED FOR: Public Hearing

Power Supply	Landon Snyder	8094
Department	*Contact*	*Extension*

Date of Previous Briefing: October 21, 2025
Estimated Expenditure:
Presentation Planned ☒

ACTION REQUIRED:

☒ Decision Preparation
- ☒ Policy Discussion
- ☐ Policy Decision
- ☒ Statutory

☐ Incidental (Information)

☐ Monitoring Report

SUMMARY STATEMENT:

Identify the relevant Board policies and impacts:

Governance Process, GP-3(4)C(1) – a non-delegable, statutorily assigned duty – Rates/fees. Ends Policy 2.2 – Utilities are in adequate supply with reasonable reserves

Chapter 19.405 RCW requires utilities such as Public Utility District No. 1 of Snohomish County (the "District") to formally adopt a Clean Energy Implementation Plan ("CEIP") by December 31, 2021 and every 4 years thereafter. The District must adopt a CEIP by the end of 2025 due to this timing requirement.

The proposed 2025 CEIP represents a filing required by the Clean Energy Transformation Act ("CETA"). The CEIP is based upon and consistent with the analysis that the utility prepares for its Integrated Resource Plan, to set interim targets for energy efficiency, demand response and renewable energy, and to identify specific actions to be taken by the utility over the next four years, that demonstrate progress towards meeting the greenhouse gas neutral and 100% clean energy standards under CETA. As such, the CEIP development process takes place within the IRP analytical and public processes.

District staff presented IRP analysis and CEIP results to the Board of Commissioners in a series of briefings throughout the IRP and CEIP development, including discussion of the biennial conservation targets, and the Clean Energy Implementation Plan. A copy of the Draft 2025 Clean

Energy Implementation Plan was posted to the District's publicly accessible website at www.snopud.com/irp on October 13, 2025.

The proposed final 2025 CEIP contains de minimums updates to the Draft 2025 CEIP but is substantively the same as the draft presented to Commission.

Board consideration of adoption of the 2025 CEIP is scheduled for December 16, 2025.

List Attachments:
Presentation
Proposed 2025 CEIP

SNOHOMISH PUD
Energizing Life In Our Communities

2025 Clean Energy Implementation Plan

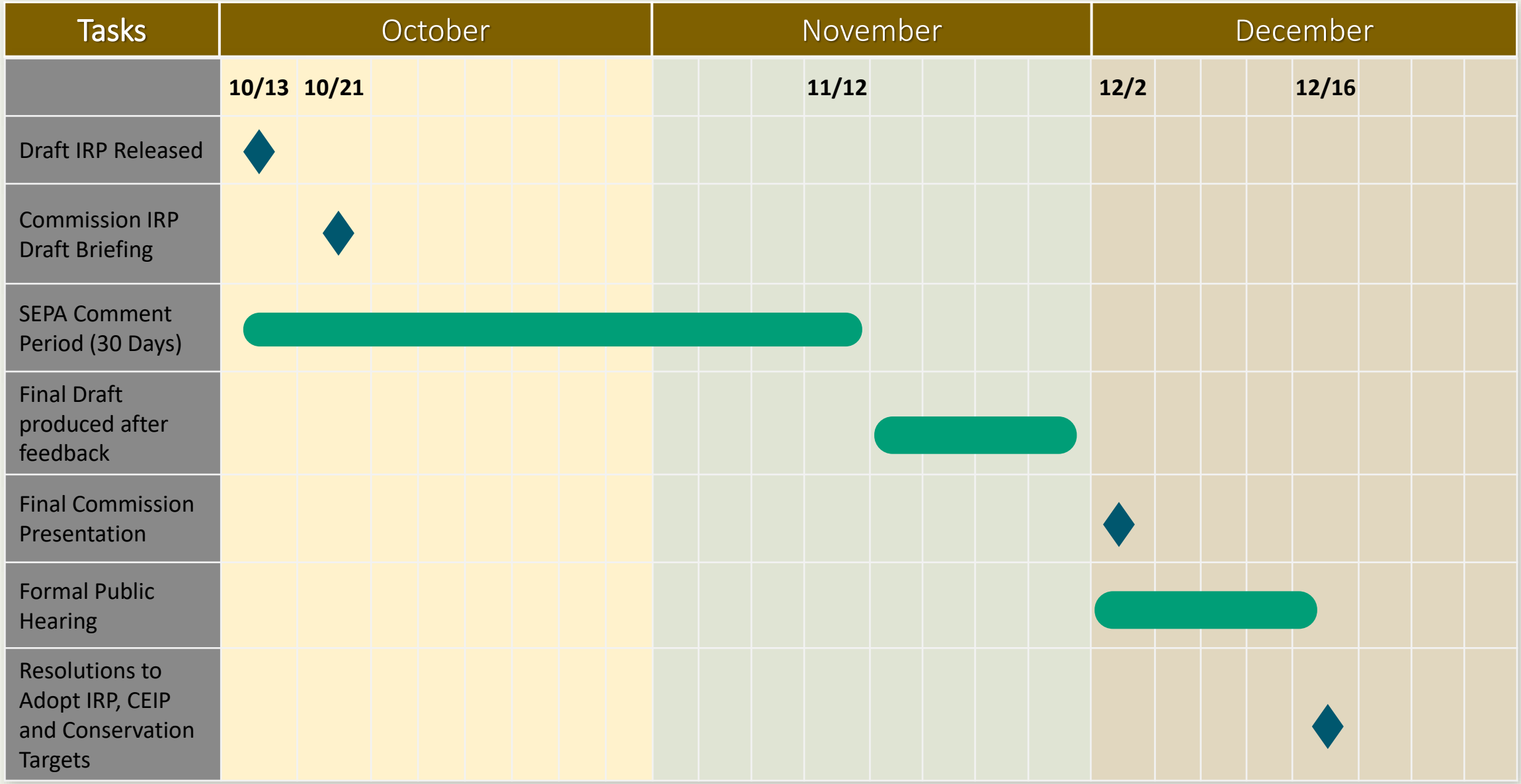
Landon Snyder – Utility Analyst
December 2, 2025
Prior Presentations – January 1, 2025, April 8, 2025, June 17, 2025, August 19, 2025, October 21, 2025

Agenda

- Context
- Clean Energy Implementation Plan (CEIP) Targets

This public hearing briefing is intended to allow for further public comment ahead of December 16, 2025, Board consideration of a Resolution to adopt the 2025 CEIP.

End of Year Timeline



Context

- Chapter 19.405 RCW requires utilities such as Public Utility District No. 1 of Snohomish County (the "District") to formally adopt a Clean Energy Implementation Plan ("CEIP") by December 31, 2021, and every 4 years thereafter. The District must adopt a CEIP by the end of 2025 due to this timing requirement.
- The PUD performs analysis for these targets in the Integrated Resource Planning (IRP) process.
- Staff have presented CEIP targets and analysis in the course of IRP briefings and released the comprehensive draft 2025 CEIP on October 13, 2025, for public comment.

Proposed CEIP Targets

- CEIP targets are derived from IRP analysis that solves for the lowest cost, lowest risk portfolio of resources to serve PUD customer load. Comprehensive analysis can be found at www.snopud.com/irp.
- CEIP targets are non-binding, and there is no penalty if actual outcomes are below or above the targets.
- The PUD is obligated to report on outcomes to the Washington State Department of Commerce at the conclusion of each 4-year period covered by each CEIP.

	2029 (4-Year)
Conservation (Cumulative Annual aMW)	17.0
Demand Response (Cumulative MW Peak Reduction)	26.6
Renewable Energy (Nameplate MW)	23.7



2025 Clean Energy Implementation Plan

2026-2030

Snohomish PUD

December 2025

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Acknowledgements

The Clean Energy Implementation Plan development process brought together staff from across the District to determine how to continue engaging our customers, and how to build upon the foundation set by the PUD's first CEIP.

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Jeff Feinberg, Energy Services	Lisa Hunnewell, Corporate Communications
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Section 1 - Executive Summary

Utility planning is a process that considers how a given utility will provide safe and reliable electric service to its customers at the lowest reasonable cost while adhering to the policy requirements of electric utilities. While the Public Utility District #1 of Snohomish County (PUD) engages in a comprehensive Integrated Resource Planning process to evaluate future needs and select appropriate resources to meet those needs, this Clean Energy Implementation Plan (CEIP) specifically examines how the PUD plans to meet the policy and regulatory objectives of the Clean Energy Transformation Act (CETA).

While the PUD's 2025 IRP establishes its Long-Term Resource Strategy, the CEIP is intended to provide a shorter-term look at targets and goals that will demonstrate the PUD's continued commitment to clean energy and satisfy the statutory requirements of CETA. The CEIP will achieve this by establishing realistic targets for clean energy use, examining specific actions recommended by the IRP, and engaging the PUD's customers for their thoughts and feedback.

Key Features of the CEIP

1. Establish interim targets for clean energy usage

2. Examine to-date progress on previous interim targets

3. Utilize all existing and validated analysis from the PUD's 2025 IRP in establishing specific targets for energy efficiency, demand response, and renewable energy

4. Identify and investigate actions specified in the 2025 IRP's Long Term Resource Plan for their applicability to CETA compliance

5. Consider highly impacted communities and vulnerable populations, and the impact the PUD's actions may have upon those customer groups

6. Meaningfully engage with the PUD's customers to gather feedback and perspectives on the PUD's clean energy future
7. Describe how the PUD expects to continue planning for CETA compliance in the future, and what to expect from future engagements

Establishing Targets

The PUD's 2025 IRP examines the needs and resources that the PUD should consider as it moves through its planning horizon. As the PUD changes the product it purchases from the Bonneville Power Administration to Load Following, the IRP assumes all PUD net load will be served by this new product and the PUD's dedicated resources which include the Jackson, Youngs Creek and Packwood hydropower facilities. This results in a clean energy outcome for Snohomish that looks largely similar to BPA's resource portfolio composition, though slightly cleaner. BPA reports a fuel mix that is, on average, approximately 92% clean, which Snohomish utilizes to characterize BPA's fuel mix, alongside the PUD's dedicated hydro facilities to inform our interim target.

When considering specific targets for energy efficiency and demand response, the PUD conducted a Conservation Potential Assessment. From this assessment, the PUD established energy efficiency targets for the Energy Independence Act. The PUD also conducted a Demand Response Potential Assessment, which informed the 2025 IRP on the availability and viability of utility scale demand response. The CEIP draws from each of these assessments not only to establish the specific targets required by statute, but to maintain consistency across PUD planning efforts and regulatory filings. **The 2026-2029 CEIP establishes an energy efficiency target of 17.0 annual average megawatts (aMW) at busbar, and a peak hour reduction demand response target of 26.6 MW.**

Specific Actions to be Taken by the PUD

Once again leveraging the analysis performed as part of the PUD's 2025 IRP, the CEIP identifies two specific actions to be considered in the 2026-2029 timeframe**: acquiring conservation and demand response.** These actions have been selected as the lowest reasonable cost methods of meeting the PUD's forecasted needs within the next four years, while maintaining reliability,

safety, and environmental standards. The CEIP must consider the potential impacts of these specific actions.

Public Process

In order to identify vulnerable populations and potential impacts of planned specific actions, the PUD engaged the public for its feedback. In an effort to collect meaningful input, **the PUD's 2025 CEIP public process included public meetings both at the PUD Headquarters and at a variety of public locations intended to meet our customers in their communities.** This engagement was in concert with the public process held for the IRP, which encompassed an **eight-month engagement with local businesses and community groups.** In the future, the PUD plans to continue its robust public engagement with a diversity of in-person and virtual meetings to cover a broad cross-section of customer types and to positively iterate making each engagement process better than before.

Evaluating the Impact of the PUD's Specific Actions

Evaluating the impacts of specific actions (acquiring conservation, demand response, and energy storage) requires the **identification of impacted communities** and the **development of metrics used to evaluate the impact of actions**.

CETA statute identifies two classifications of impacted communities: "highly impacted communities" and "vulnerable populations" that may be impacted. The CEIP utilized the Washington Department of Health's Cumulative Impact map to identify highly impacted communities as required by statute[1], which can be found in Appendix B. The PUD is also continuing to monitor the two categories of vulnerable populations developed in the 2022-2025 CEIP study period, reflective of feedback from that public engagement process and from feedback in our most recent public engagement.

[1] As defined in RCW 19.405.020(23)

These vulnerable populations are listed below and described in more detail in Section 5:

1. Customers that have a high energy burden of at least 7% and,
2. Customers living in distribution system constrained area

The metrics identified as appropriate to measure the impacts of actions in these communities are listed below and described in more detail in Section 6:

1. Conservation program participation of high energy cost burden customers and,
2. Forecasted distribution constraint relief from resource acquisition in distribution constrained areas

Resource Adequacy

As a utility that operates within the Bonneville Power Administration's Balancing Authority (BPA BA), the PUD has a different set of considerations for resource adequacy than other utilities that manage their own BA.

Because the PUD has opted to become a Load Following customer of BPA, the PUD does not have the same Resource Adequacy requirements as identified in our previous CEIP. The PUD now fully utilizes BPA to provide and guarantee its Resource Adequacy. Enabling BPA to provide the PUDs Resource Adequacy requirements alleviates significant portfolio pressure from the PUD and enables examination of clean resource combinations not previously possible. For the purpose of this CEIP, the PUD considers compliance with Western Resource Adequacy Program for the PUD's load and resources to be the resource adequacy standard. This is being accomplished on the PUD's behalf by BPA's compliance with WRAP standards for the PUD's loads and resources.

Continuing Commitment to Clean Energy

The PUD's Board of Commissioners has a long-standing policy to meet all future load growth through a combination of cost-effective conservation and non-emitting resources. The 2025 IRP establishes a Long-Term Resource Strategy that is consistent with this vision, and the CEIP team will continue to examine the PUD's expected actions and resource developments to ensure that

the PUD is progressing toward the 2030 and 2045 clean energy standards while equitably distributing the energy and non-energy benefits of its actions.

Because the PUD views the commitment to the transition to clean energy as ongoing, the CEIP reinforces the findings in the IRP and helps lay the foundation for how **the PUD seeks to continue its commitment to non-emitting resources in its power supply portfolio and meet customer needs with clean, affordable, and reliable electricity.**

Section 2 - Identifying Targets

The process of identifying targets in the interim compliance period (2026-2029) accomplishes two tasks set forth in statute: 1) identifying specific targets for new resource additions consistent with the IRP and Clean Energy Action Plan, and 2) identifying those resources which will serve retail load consistent with the existing portfolio, resource additions called for in the IRP and Clean Energy Action Plan, and categorized as renewable resources or non-emitting resources in the Clean Energy Transformation Act statute.

Specific Targets by Resource Type

The CEIP must establish specific targets for (a) Energy Efficiency (as expressed in MWh of first-year savings), (b) demand response (in peak hour MW), and (c) Renewable energy (in MWh)[2]. The 2025 IRP identifies two such planned investments in its long-term resource plan relevant to the four-year interim compliance period of 2026 - 2029. These targets are expressed in Figure 2-A as they are likely to appear in the 2025 IRP. These resources are cumulative in nature, such that that the 2029 figure expressed is the result of all such cumulative achievements by December 31, 2029 of the compliance period.

Figure 2-A: Specific Targets by Resource Type (Cumulative)

	2029 (4-year)
Conservation (Cumulative annual aMW)	17.0
Demand Response (Cumulative peak hour MW)	26.6

Figure 2-B is reproduced in the units called for in the units specified under the applicable administrative code in figure 2-B below.

[2] WAC 194-40-200 (3)

Figure 2-B: Specific Targets by Resource Type (Cumulative)

	2029 (4-year)
Conservation (Cumulative annual MWh)	148,920
Demand Response (Cumulative Peak Hour MW)	26.6

Interim Targets for the Compliance Period

The PUD's switch to Load Following marks a significant operational departure from its historic method of serving its customer load. Previously, the PUD purchased the Block/Slice product from BPA which delivered a fixed amount of power plus a variable amount of power determined by the generating capability of the federal system. This allowed the PUD to manage its own load needs and to utilize surplus clean energy for the benefit of its customers. Further, it supplied clean energy in excess of the 8% unspecified power in BPA's fuel mix allowing the PUD to target 100% clean as our 2022-2025 interim target.

The PUD is proud to confirm that under current CETA reporting standards and utilizing the Block/Slice product, it met its 100% clean target for 2022-2025.

However, the Block/Slice product also exposed the PUD's customers to significant costs related to market price excursions and Resource Adequacy determinations. After significant analysis and public process, the PUD elected to become Load Following customers of BPA which significantly reduced both actual costs and risk for our ratepayers. This change resulted in a roughly $40M cost savings in 2026 relative to the 2025 PUD Power Supply budget - a savings that benefits all PUD ratepayers. This action did, however, change the way that we are able to account for BPA power in our portfolio. We no longer receive "surplus" BPA – instead BPA delivers power to us 1:1 with our load needs, after applying certain PUD-owned resources. As such, BPA's fuel mix is by and large our fuel mix; historically, approximately 92% clean on average.

Figures 2-E and 2-F present data targets in the format specified in statute. Here renewable energy includes all renewable energy (including the PUD's share of BPA Power using the methodology outlined in Section 5 of the 2025 IRP) and non-emitting resources (using the same methodology specified in Section 5 of the 2025 IRP). These targets are provided on a forecast basis, using an assumption of normal (or P50) weather as it affects load and hydropower generation.

Figure 2-E: Interim Targets for the Compliance Period, MWh

	2026	2027	2028	2029
Renewable Energy	5,661,451	5,741,107	5,843,682	5,900,109
Non-Emitting Energy	732,159	742,977	755,896	761,244
Total Renewable and Non-Emitting Resources	6,393,611	6,484,083	6,599,578	6,661,353
Retail Load Forecast	6,926,090	7,024,430	7,149,321	7,274,639

Figure 2-F: Interim Targets for the Compliance Period, Percentage

	2026	2027	2028	2029
Renewable Energy	82%	82%	82%	81%
Non-Emitting Energy	11%	11%	11%	10%
Percentage of Retail Load Served by Renewable or Non-Emitting Resources	93%	93%	93%	91%

Section 3 - Specifying Actions

A Clean Energy Implementation Plan must demonstrate the specific actions a utility plans to take to comply with CETA requirements and describe how specific actions are consistent with IRP and the Clean Energy Action Plan. The specific actions planned are derived directly from the 2025 IRP and its sub-component Clean Energy Action Plan and are the planned resource additions to meet the PUD's defined goals. The CEIP identifies two specific actions to be considered in the 2026-2027 timeframe for the purposes of the CEIP: acquiring conservation and demand response.

The first identified action **is continuing the PUD's investment in and commitment to energy efficiency and conservation.** Conservation represents the foundation for the PUD's resource plan by providing multiple value streams for meeting the PUD's future needs; by reducing future needs, conservation presents itself as a viable and cost-effective alternative to expensive resource acquisitions. Further, the capacity benefit provided by its reduction during peak hours helps manage potential capacity costs of BPA Power and Transmission products. While the PUD has a robust conservation portfolio already established, the CEIP hopes to explore its accessibility to all customers, and how the PUD can improve and increase conservation portfolio availability to vulnerable populations throughout Snohomish County.

The second identified action is continuing development of local demand response and smart rate programs with our customers. Demand response represents a cost-effective capacity addition to help the PUD meet capacity needs and reduce supply-side capacity resource acquisitions. While the PUD has pilot demand response programs established, the CEIP hopes to continue exploring its accessibility to all customers, and determining how the PUD can improve and increase demand response program availability to Snohomish County. Development of demand response programs will be interdependent on the development and rollout of the PUD's Advanced Meter Infrastructure (AMI) project.

Figure 3-A provides the scale and type of planned actions, expected by 2025.

Figure 3-A: Specific Resource Additions over Compliance Period by Resource Type (Cumulative)

	2029 (4-year)
Conservation (Cumulative annual aMW)	17.0
Demand Response (Cumulative peak hour MW)	26.6

Section 4 - Engaging the Public

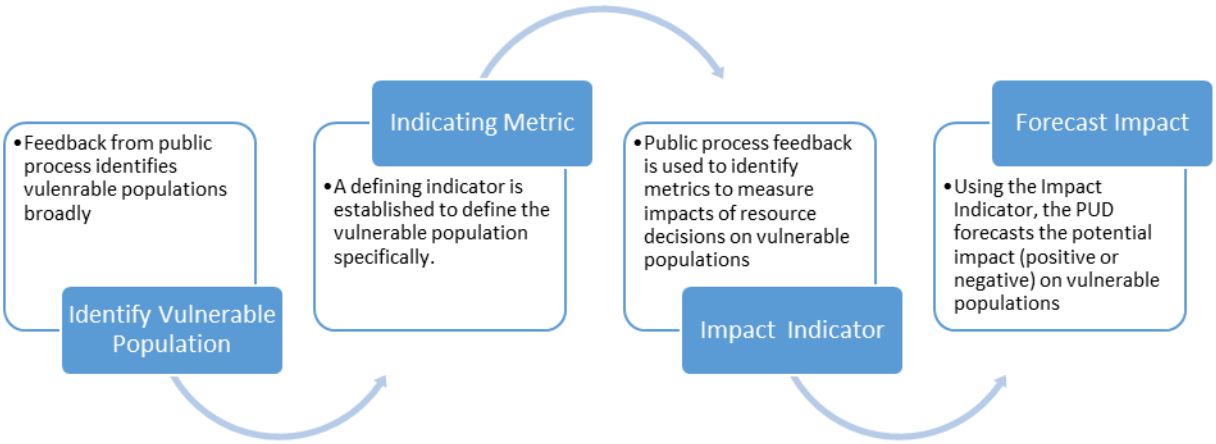
As a publicly owned utility, the PUD believes that its customers voices are critical to our mission of serving Snohomish County with safe, reliable, and environmentally responsible power at the lowest reasonable cost. Under PUD organizing statutes, our regulatory body is made up of three elected PUD Commissioners who serve as the decision-making foundation upon which the PUD operates. While this CEIP will be discussed and considered in open public Commission meetings, it was the goal of the CEIP team to perform additional targeted outreach to our customers.

The PUD began its public outreach for the 2025 CEIP with acknowledgements that the 2021 CEIP intended to expand the public process the 2020 pandemic subsided. The PUD's 2021 and 2023 IRP public process proved successful, and these efforts helped develop the public engagement process for the 2025 IRP and 2025 CEIP's. Future CEIPs will continue to build on successes in the 2025 outreach and include a more expansive, community-based, more inclusive public process, and the PUD looks forward to setting a high standard for utility customer engagement.

The primary purpose of the public processes was to receive feedback and input to inform an identification of vulnerable populations as defined under the statute, and to explore meaningful metrics that may measure how planned actions may impact community groups. The PUD also engaged the public in their perception of planned actions listening for public feedback on how actions could best meet community needs. The PUD's Board of Commissioners is also a critical component of the public process by virtue of their policy leadership on the 2025 IRP for which the CEIP relies, the feedback they provide during IRP briefing sessions, and through the public comment processes that Commission briefings provide.

The interrelationship of vulnerable population identification, measurement, and forecast impacts is described in Figure 4-A below:

Figure 4-A: Public Process and Development of Vulnerable Population, Indicator and Forecast Impact Relationships



For the 2026-2029 CEIP, the public engagement strategy consisted of four parts:

- A community-leaders forum,
- Four open house events to gather feedback
    - Two traditional open house events incorporating IRP and CEIP feedback,
    - Two community-based events utilizing an inclusive, gamified feedback process,
- A virtual open house offering via the PUD's PowerTalks series, and;
- Commission Meeting Briefings and Public Comment periods on planned CEIP efforts

A summary of the high-level themes across public processes is as follows:

- Customers supported continuing to prioritize the vulnerable populations identified in the PUD's 2021 Clean Energy Implementation Plan (CEIP). These groups were previously defined as "distribution-constrained customers" and "energy-burdened customers." Customers unanimously agreed that these definitions remain relevant, and maintaining consistency allows for tracking impacts over time.
- PUD customers understand the importance of reliability as it relates to their ability to maintain a high quality-of-life at home, in their workplace, the reliability of the businesses they frequent, and increasingly, as they work from home. In this context, customers want PUD resource plans that consider reliability for the community as a whole and in the neighborhoods where they live, work and play. This includes adequately

planning for the potential of future innovation, such as electric vehicles and rooftop solar growth.

- The PUD should ensure any programs to support distribution constrained customers account for non-homeowners. Although the vulnerable population was appropriately broadly defined an emphasis was noted for renters or other living situations and services and programs should account for some customers inability to participate.
- Future PUD public processes should continue to expand offerings with an emphasis on connecting with community groups, finding ways to connect with customers that may not speak English as a first language, and providing venues for discussion or learning to customers where those communities are, and providing venues for discussion to community members without regular access to computers or the internet.

The feedback received thus far has been valuable and has been accounted for when considering the specific actions identified in this CEIP.

Community Leaders Forum

A community leaders forum was held at the PUD headquarters in Everett, WA on May 23, 2024 inviting service organizations, local business leaders and governmental planning teams. This forum represented a wide cross section of the county customer base and insight into challenges faced by customers. Service organizations were invited to present the challenges faced by low-income customers and gave feedback on the PUD planning process and resource decisions. Feedback received during the community leaders forum supported both vulnerable population choices with the high cost of energy investments and upgrades were identified as a significant challenge across sectors and reliable energy were the highest priorities for our customers.

Open Houses

The PUD conducted four public engagement events as part of its outreach efforts: two traditional-format open houses and two interactive, gamified community events. The open houses were held at the Everett Headquarters and the Arlington Clean Energy Center, while the community events took place at Cedar Valley Community School and a senior center in

Snohomish County. The PUD recognizes the importance of inclusivity of our diverse community and included support for Spanish speaking households at our community open houses. Future community outreach will incorporate feedback received from the community on the importance of continuing to engage the diverse community the PUD serves.

In total, nearly 100 community members participated, engaging directly with the Integrated Resource Plan (IRP) team to share their insights on the PUD's resource planning process and the Clean Energy Implementation Plan (CEIP). Feedback across all events consistently supported maintaining the current definition of vulnerable populations, with additional consideration for non-homeowners through programmatic approaches.

Participants identified renewable energy and affordable electricity as their highest priorities, closely followed by reliable service. These community-identified priorities are reflected in the criteria used to define vulnerable populations within the planning framework.

Section 5 - Identifying Highly Impacted and Vulnerable Communities

CETA statute asks utilities to identify both Highly Impacted communities, using a set methodology, and Vulnerable Populations using a public process.

Identifying Highly Impacted Communities

The PUD follows the Washington State Department of Commerce guidance on identifying Highly Impacted Communities provided in their CEIP reporting template. In general, that guidance identifies census tracts with "cumulative environmental health disparities" index values of 9 or above (as determined by the Washington state Department of Health), or census tracts containing Tribal Lands as highly impacted communities for consideration in CEIP documents. These identified Census tracts are provided in Appendix B and contain a total of 29 Census Tracts. Ten (10) of these Census tracts were identified because their disparity index value was greater than 9, and nineteen (19) were identified because they contained Tribal Lands.

Identifying Vulnerable Communities

Through the public engagement processes, the PUD distilled feedback to identify vulnerable populations related to the provision of electricity service that the PUD could meaningfully impact through resource acquisition actions.

Energy-Cost-Burdened Customers

The PUD is sensitive to the needs of its community and the economic pressures they face. While the PUD offers assistance programs for those customers who are income-qualified, there may be other customers who face a high energy burden but whose income is above the threshold required to qualify for the current assistance program. Public feedback directly refenced a public interest in an expansive consideration of customers who may have a harder time paying their bills. **To define this vulnerable population, the PUD has used an indicator on high energy cost burden, which defines a customer as having a high energy burden if their energy costs are 7% or more of their income.**

One community that we are actively monitoring are those energy-cost-burdened customers who rent rather than own their homes. This sub-population may have different challenges related to energy burden that we want to better understand. We have not identified this group as a stand-alone Vulnerable Population yet but will consider this action in the next CEIP cycle based on our observations during the 2026 – 2029 period.

Customers Living in Distribution System Constrained Areas

As the PUD reviews its distribution system, there are areas in Snohomish County that are quickly growing. This growth is just one factor that could contribute to the distribution system in a particular geographic region becoming constrained. While existing customers may not see a reduction to reliability, increased usage of the existing system could produce future constraint. In addition, distribution constrained systems are at increased risk of reliability interruptions due to increasingly frequent extreme weather events.

During the public feedback process, service reliability and pro-actively planning for future customer load, especially for those in parts of the service territory that may be more vulnerable to service interruptions was discussed. The public feedback sessions indicated a desire for consideration of non-homeowners in the design of programs. The PUD proposes to maintain its second vulnerable population of "customers living in a distribution system constrained area" to continue proactively assessing the potential benefits of resource additions in these areas. Consideration of this vulnerable population model could help inform future decisions about where resources might be sited in Snohomish County to maximize the benefit not only for the PUD's portfolio, but also for those customers whose local distribution system may need reinforcement.

To define this population, the PUD has used as an indicator those customers who are on Distribution System Circuits that have limited capacity on the primary line serving the circuit.

Section 6 - Assessing Impacts of Specific Actions on Identified Communities

Assessing the impacts of specific actions requires a layered look in the context of CEIP regulatory obligations. Utilities must provide an expectation of the energy or nonenergy benefits and costs, provide an expectation of expected effects of specific actions, and a description of how the utility intends to reduce risk to vulnerable populations in the Clean Energy transition.

In many respects, the PUD's Clean Energy Implementation Plan can be characterized as a conveyance of benefits to identified communities, rather than a distribution of costs or harms. This is because the largest investments in the CEIP are conservation and demand response measures that seek to lower energy consumption, bills, and distribution system strain for customers across the service territory. In addition, because this is the lowest cost way for the PUD to meet its portfolio needs, it is expected that this course of action will result in the lowest costs to customers in identified communities.

Expected Energy and Nonenergy Benefits and Costs

Because conservation is the single most cost-effective resource that can be acquired, the PUD prioritized conservation as a starting point for the measurement of energy and non-energy benefits as it represents the largest investment by scale. The PUD will continue analysis throughout the interim compliance period. In addition, it is worth noting that because the planned actions are the result of a lowest reasonable cost plan analysis, the actions anticipated are expected to result in the lowest cost to all customers, including those in Highly Impacted Communities and among Vulnerable Populations.

Expected Energy Benefits

Expected energy benefits of conservation were developed using a geospatial analysis tool the PUD developed as part of the Conservation Potential Assessment process. This tool allows the PUD to model the cost-effective conservation geospatially to see what cost-effective conservation potential there may be in Highly Impacted Communities and Vulnerable Populations that are mappable.

It is expected that 19.14% of the cumulative cost-effective conservation and cumulative demand response planned by 2029 will be located in Highly Impacted Communities. Additional information is provided in Appendix C.

Staff estimates that 19.47% of the cumulative conservation and cumulative demand response planned by 2029 will be located in areas with Distribution System constraints. Additional information on this breakdown is provided in Appendix D.

Expected Non-Energy Benefits

Non-energy benefits are an included component of the Conservation Potential Assessment are included as a financial consideration in the CPA methodology. To estimate the non-energy benefits of conservation in Highly Impacted Communities and Vulnerable Populations, the total non-energy benefit total for cost-effective conservation measures was calculated and applied to the proportion of cost-effective energy found for the applicable identified communities in terms of expected energy benefits. The total non-energy benefits for cost-effective conservation to be achieved by 2029 is estimated at $6.7 million in net present value lifetime savings, with all of it in the residential sector. The estimated non-energy benefits within Highly Impacted Communities is estimated at $1.28 million in lifetime savings expressed in net present value terms. The estimated nonenergy benefits within the Vulnerable Population of Distribution Constrained Areas is estimated at $1.3 million in lifetime savings expressed in net present value terms.

Other Energy and Nonenergy Benefit Considerations

The PUD also plans to develop demand response, including time-of-use rates within the interim compliance period. As development activities take further shape, PUD will be proactive in considering the impact of these activities on highly Impacted Communities and Vulnerable Populations and will seek to minimize harm and maximize benefits of actions, as appropriate, and on balance with other utility obligations.

Expected Effect of Specific Actions

The overall anticipated effect of the specific activities identified in the 2025 CEIP is that they will result in the lowest reasonable costs to PUD customers. However, it is also anticipated that the planned actions will produce additional benefits for Highly Impacted Communities and Vulnerable Populations.

Energy Bill Savings

It is expected that conservation and demand response will reduce the energy bills of customers that participate. As stated in the section above, it is anticipated that 19.14% of the energy bill savings from planned conservation actions will occur within Highly Impact Communities and 19.47% of the energy bill savings from planned conservation actions will occur within the Vulnerable Population of Customers in Distribution System Constrained Area.

Distribution System Relief

The PUD further expects that conservation savings will provide additional distribution system capacity in areas where there is little existing capacity on the circuit. Figure 5-A above provides a chart of the circuits with limited capacity. It is anticipated that planned conservation activities will add at least 3.31 aMW of additional capacity to these areas by 2029.

How the PUD Intends to Reduce Risks to Clean Energy Transition to Vulnerable Communities

The PUD's decision to change power products to Load Following is one of the primary strategies for protecting vulnerable communities moving forward. The product switch not only provides significant cost savings and rate shock mitigation for all PUD ratepayers but improves reliability and delivery certainty combined with the NT transmission product. Further, it frees up PUD resources to focus on projects that will benefit vulnerable populations as identified in the IRP's Action Plan including demand response and locally sited solar that provide system benefits and regulatory value.

Section 7 - Ensuring Resource Adequacy

The Clean Energy Transformation Act requires utilities to make "a determination of resource adequacy metrics for the resource plan…"[3]. The PUD is in a unique situation to do so because of its relationship to BPA and the BPA Power and Transmission products that the PUD is procuring. The PUD elected to change to the BPA Load-Following product on October 1, 2025, in part because of analysis showing it would help cost-effectively meet regional resource adequacy program requirements. The BPA Load-Following product is considered to be full-requirement load service, whereby BPA provides all power needed for load service after dedicated utility-owned resources are brought to load. BPA has also joined the Western Resource Adequacy Program, and its load service obligations (inclusive of the PUD) are covered by that program. As a result, the PUD considers the Western Resource Adequacy Program (WRAP) to be the appropriate current measure, and the PUD is meeting WRAP program requirements by virtue of taking a WRAP-compliant BPA Power product.

The Western Resource Adequacy Program

The Western Resource Adequacy Program (WRAP) is a voluntary program established in 2019 in which participating utilities in the western region engage in reliability planning and resource sharing to reach regional capacity compliance, helping utilities to meet resource adequacy needs at the lowest cost. In the late 2010s, studies from several organizations concluded that the western region may reach serious capacity shortages by the mid-2020s, which would critically impact regional reliability.[4][5] WRAP was created in response to these concerns, helping participants to maintain reliability in a range of conditions, which is especially important during

[3] RCW Chapter 19.285.030 (1)(g). https://app.leg.wa.gov/RCW/default.aspx?cite=19.280.030
[4] Gangelhoff, G. (2020, June 16). *E3 projects Substantial capacity shortfall in the Pacific Northwest - E3*. E3. https://www.ethree.com/e3-projects-substantial-capacity-shortfall-in-the-pacific-northwest/

[5] PNUCC System Planning Committee. (2019). *Northwest Regional Forecast of Power Loads and Resources 2020 through 2029*. https://www.pnucc.org/wp-content/uploads/PNUCC-2019-NRF.pdf

this current period of transition as coal-fired plants are retiring and reliance on variable renewable resources increases.[6]

The primary components of WRAP are forward-showing and an operational program. In forward-showing, participants demonstrate that they have sufficient regional capacity secured around 7 months in advance. An operational program provides short-term forecasts, and if a participant is projected to have a capacity deficit they will be supplied with resources from those with a surplus. The program is still in the late stages of its full development and not yet fully binding, expecting to be a fully binding program by 2028.

[6] Energy & Environmental Economics (E3). (2019). Exploring a resource adequacy program for the Pacific Northwest. In *An Energy System in Transition* [Report]. https://www.westernpowerpool.org/private-media/documents/2019.11.12_NWPP_RA_Assessment_Review_Final_10-23.2019.pdf

Section 8 - Looking to the Future

The PUD is committed to a clean energy future and is well-positioned to meet compliance standards under the new CETA provisions. While this CEIP continues to build upon the foundation set by the 2021 CEIP, the PUD recognizes areas to focus on for further development in the next CEIP and throughout the interim compliance period of 2026-2029.

Continuing to Develop Robust Public Processes

The PUD has embraced the public process components of the CEIP and has been making a concerted effort to build increasingly robust public engagement processes each IRP cycle. 2023 IRP Update public processes included more public open house opportunities than the 2021 IRP, and the 2025 IRP had more than the 2023 IRP. In addition, the 2025 IRP held Open Houses at different locations across the service territory, included language services for potential participants who did not speak English as a first language, and included outreach to seniors, in an effort to capture a broad spectrum of customer perspectives. Future public processes will meet our internal expectation of exceeding customer's expectations, taking a customer-centric approach to service provision, and building on previous efforts.

Indicator Development

The PUD intends to continue to develop indicators that capture how planned actions impact identified communities as additional CEIP's are developed, in consultation with internal subject matter experts and input from the public. It is the PUD's intention to develop indicators, avoid negative impacts, and drive towards positive benefits throughout the interim compliance period.

Appendix A.

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Appendix B. List of Identified Highly Impacted Communities in Snohomish County

The PUD follows the Washington State Department of Commerce guidance on identifying Highly Impacted Communities provided in their CEIP reporting template. This guidance instructs utilities to reference Department of Health data on census tracts with an Environmental Health Disparities index score of 9 or 10 (out of a range of 1 to 10) and census tracts that contain tribal lands.

This dataset can be found online at the Department of Health's website[7]:

Census Tract	County Name	Highly Impacted Community (Yes/No)	Tribal Lands (Yes/No)	Environmental Health Disparities Topic Rank
53061053400	Snohomish	Yes	Yes	3
53061040100	Snohomish	Yes	Yes	8
53061040200	Snohomish	Yes	No	10
53061040700	Snohomish	Yes	No	9
53061040800	Snohomish	Yes	No	10
53061041100	Snohomish	Yes	No	9
53061041202	Snohomish	Yes	No	9
53061041806	Snohomish	Yes	No	10
53061041901	Snohomish	Yes	No	9
53061041904	Snohomish	Yes	No	10
53061051701	Snohomish	Yes	No	9
53061051803	Snohomish	Yes	No	9
53061052104	Snohomish	Yes	Yes	7
53061052803	Snohomish	Yes	Yes	5
53061052804	Snohomish	Yes	Yes	5
53061052805	Snohomish	Yes	Yes	7
53061052903	Snohomish	Yes	Yes	8
53061052904	Snohomish	Yes	Yes	8

[7] https://www.doh.wa.gov/DataandStatisticalReports/WashingtonTrackingNetworkWTN/ClimateProjections/CleanEnergyTransformationAct/CETAUtilityInstructions

53061052905	Snohomish	Yes	Yes	8
53061053102	Snohomish	Yes	Yes	4
53061053202	Snohomish	Yes	Yes	1
53061053301	Snohomish	Yes	Yes	1
53061053302	Snohomish	Yes	Yes	3
53061053508	Snohomish	Yes	Yes	6
53061053700	Snohomish	Yes	Yes	5
53061940001	Snohomish	Yes	Yes	7
53061940002	Snohomish	Yes	Yes	5
53057951100	Skagit	Yes	Yes	2
53029971700	Island	Yes	Yes	1

Appendix C. Expected Energy Benefits in Highly Impacted Communities

Census Tract	County Name	Cumulative 2029 EE (aMW)	Cumulative 2029 DR (PH MW)
53061053400	Snohomish	0.14	0.31
53061040100	Snohomish	0.33	0.27
53061040200	Snohomish	0.23	0.18
53061040700	Snohomish	0.27	0.26
53061040800	Snohomish	0.18	0.14
53061041100	Snohomish	0.15	0.21
53061041202	Snohomish	0.11	0.19
53061041806	Snohomish	0.07	0.20
53061041901	Snohomish	0.30	0.24
53061041904	Snohomish	0.08	0.13
53061051701	Snohomish	0.13	0.20
53061051803	Snohomish	0.06	0.15
53061052104	Snohomish	0.10	0.12
53061052803	Snohomish	0.35	0.36
53061052804	Snohomish	0.13	0.26
53061052805	Snohomish	0.12	0.19
53061052903	Snohomish	0.15	0.20
53061052904	Snohomish	0.06	0.18
53061052905	Snohomish	0.08	0.17
53061053102	Snohomish	0.13	0.26
53061053202	Snohomish	0.07	0.22
53061053301	Snohomish	0.17	0.25
53061053302	Snohomish	0.11	0.31
53061053508	Snohomish	0.08	0.11
53061053700	Snohomish	0.08	0.19
53061940001	Snohomish	0.36	0.44
53061940002	Snohomish	0.07	0.20
53057951100	Skagit	0.01	0.02
53029971700	Island	0.07	0.31
	System Total Cumulative 2029 Potential	**17.0 Annual aMW**	**26.6 PH[8] MW**

[8] Peak Hour

	Highly Impacted Community 2029 Potential	**4.20 Annual aMW**	**6.25 PH MW**
	Percent in Highly Impacted Communities	**24.71%**	**23.49%**

Appendix D. Expected Energy Benefits in Distribution Constrained Areas

Station	Circuit	Cumulative 2029 EE (aMW)[9]	Cumulative 2029 DR (PH MW)
BUNK FOSS	4113	0.04	0.06
CASCADE	2087	0.04	0.10
CASCADE	2088	0.04	0.11
CASCADE	2089	0.04	0.08
CASCADE	2090	0.05	0.09
CLEARVIEW	586	0.04	0.06
CLEARVIEW	587	0.05	0.13
EAST MARYSVILLE	38	0.04	0.10
EVERETT	101	0.03	0.03
EVERETT	112	0.07	0.11
EVERETT	3702	0.01	0.01
FRONTIER	534	0.07	0.11
FRONTIER	535	0.06	0.14
FRONTIER	536	0.07	0.11
GIBSON	2897	0.05	0.14
GOLDBAR	554	0.10	0.22
GOLDBAR	555	0.03	0.07
GRANITE FALLS	4614	0.02	0.02
GRANITE FALLS	4615	0.04	0.13
GRANITE FALLS	810	0.04	0.12
GRANITE FALLS	811	0.03	0.07
HARBOUR POINTE	4676	-	-
HARDESON	4556	0.00	0.00
HARTFORD	3117	0.03	0.10
HARTFORD	3119	0.03	0.09
HARTFORD	3120	0.05	0.14
HILTON LAKE	497	0.03	0.08
HILTON LAKE	498	0.01	0.05
LAKE SERENE	339	0.05	0.08
LAKE STEVENS	124	0.05	0.14

[9] Some circuits in this table do not have EE or DR values because those circuits do not normally carry customers or do not have installed meters.

LAKE STEVENS	125	0.05	0.14
LAKE STEVENS	273	0.02	0.06
LAKE STEVENS	274	0.06	0.17
LAKE STEVENS	4034	-	-
NORTH CAMANO	315	0.01	0.05
NORTH CAMANO	316	0.03	0.14
NORTH CREEK	1413	0.05	0.08
NORTH MOUNTAIN	2514	0.06	0.15
NORTH MOUNTAIN	2515	0.02	0.05
NORTH MOUNTAIN	2516	0.18	0.04
PAINE FIELD	1729	0.06	0.07
PAINE FIELD	1730	0.04	0.06
PAINE FIELD	1731	0.03	0.08
PAINE FIELD	1732	0.12	0.03
PORT GARDNER	6022	-	-
PORT GARDNER	6023	-	-
PORTAGE	3502	0.07	0.05
SILVER LAKE	253	0.04	0.10
SKY VALLEY	6046	0.03	0.02
SKY VALLEY	6047	0.03	0.10
SKY VALLEY	6048	0.01	0.05
SMOKEY POINT	1509	0.05	0.11
SMOKEY POINT	1510	0.02	0.04
SNOHOMISH	123	0.06	0.10
SOUTH CAMANO	1530	0.02	0.07
SOUTH CAMANO	1531	0.01	0.05
SOUTH CAMANO	1532	0.04	0.17
SOUTH CAMANO	1533	0.03	0.11
SULTAN	1593	0.02	0.06
SULTAN	1595	0.06	0.14
SULTAN	5004	-	-
SUNSET	5208	0.03	0.14
SUNSET	5209	0.02	0.07
SUNSET	5210	0.02	0.06
SUNSET	5211	0.01	0.04
SUNSET	5212	0.03	0.10
TENTH STREET	327	-	-

THRASHERS CORNER	3304	-	-
THREE LAKES	1818	0.02	0.07
THREE LAKES	1819	0.04	0.13
THREE LAKES	1821	0.02	0.05
TURNERS CORNER	1429	0.01	0.03
TURNERS CORNER	1430	0.06	0.08
TURNERS CORNER	1431	0.04	0.05
TWIN CITY	6035	-	-
WALLACE RIVER	4485	0.02	0.05
WALLACE RIVER	4486	0.05	0.02
WALLACE RIVER	4487	0.04	0.11
WEST MONROE	3361	0.09	0.05
WEST MONROE	3362	0.09	0.08
WEST MONROE	3363	0.04	0.07
WEST MONROE	631	0.07	0.06
WEST MONROE	632	0.03	0.07
WEST MONROE	633	0.02	0.06
WOODS CREEK	1808	0.03	0.02
WOODS CREEK	1809	0.05	0.14
WOODS CREEK	1810	0.05	0.03
WOODS CREEK	1811	0.03	0.10
	System Total Cumulative 2029 Potential	**17.0 Annual aMW**	**26.6 PH[10] MW**
	Distribution Constrained Areas 2029 Potential	**3.36 Annual aMW**	**6.64 PH MW**
	Percent in Distribution Constrained Areas	**19.76%**	**24.96%**

[10] Peak Hour

Appendix E: Climate Commitment Act – Forecast of Loads and Resources

Overview

The PUD is utilizing Appendix E to identify the applicable and appropriate forecasts of loads and resources from the CEIP for use in calculating the PUD's cost burden. The PUD has included information in this Appendix E within the IRP and CEIP study periods for Emission Years not yet allocated by Ecology.

Because Snohomish has become a Load Following customer, Snohomish assumes that its only source of emissions will be from the Load Following product. Snohomish assumes that it will bring its dedicated resources to load at their critical values first (all non-emitting), with the remainder being served by BPA Load Following.

Forecast of Loads

For the Emission Years 2027 through 2029, the following total retail loads were forecast:

	2027	2028	2029
Total Retail Load (MWh)	7,024,430	7,149,321	7,274,639

Forecast of Bonneville Power Administration Electricity Received and Total Cost Burden

Because BPA is the only source of emissions in Snohomish's portfolio, we can directly assume that the cost burden of service will be derived directly from BPA deliveries. BPA's associated carbon content is forecasted based on BPA's most recent ACS value calculated with the California Air Resources Board[11].

	2027	2028	2029
BPA Energy Received (MWh)	6,754,333	6,871,782	6,920,400
BPA ACS Factor (MTCO2 / MWh)	.0452	.0452	.0452
Total BPA Emissions (MTCO2)	305,296	310,605	315,802

Administrative Cost Burden

Under the CCA final rule, utilities can receive allowances based on their administrative costs of "establishing and maintaining compliance accounts, tracking compliance, managing compliance instruments, and meeting the reporting and verification requirements of this chapter." The information required to calculate this administrative cost is not found in the CEIP and therefore is not included in this Appendix. The PUD anticipates Ecology to produce a high-level formula

[11] Mandatory GHG Reporting - Asset Controlling Supplier | California Air Resources Board

approach for determining Administrative Cost Burden that is not tied to specific utility expenditures.

BUSINESS OF THE COMMISSION

Meeting Date: December 2, 2025 **Agenda Item:** 6C

TITLE

Public Hearing on Proposed 2026-2027 Biennial Conservation Targets and Ten-Year Conservation Potential Estimate

SUBMITTED FOR: Public Hearing

Energy Services	Jeff Feinberg	1840
Department	*Contact*	*Extension*

Date of Previous Briefing: October 21, 2025
Estimated Expenditure: Presentation Planned ☒

ACTION REQUIRED:

☒ Decision Preparation
☒ Policy Discussion
☐ Policy Decision
☒ Statutory

☐ Incidental (Information)

☐ Monitoring Report

SUMMARY STATEMENT:

Identify the relevant Board policies and impacts:

Governance Process, GP-3(4)C(1) – a non-delegable, statutorily assigned duty – Rates/fees. Ends Policy 2.2 – Utilities are in adequate supply with reasonable reserves

The Energy Independence Act, Chapter 19.285 RCW, requires that the District formally adopt by Resolution two-year conservation targets and a ten-year conservation potential estimate, and submit them to the Washington State Department of Commerce on or before January 1, 2026. WAC 194-37-070 requires these targets and estimates to be updated every two years.

At the Commission's public meetings on August 19, 2025, and October 21, 2025, staff presented the planning assumptions and portfolio results associated with the proposed 2025 Integrated Resource Plan ("IRP") that included: the range of conservation potential identified in the utility specific analysis conducted by Lighthouse Energy Consulting; and the range of ten-year conservation potential identified through an integrated portfolio analysis. The integrated portfolio analysis was used in the 2025 IRP, consistent with the Washington Administrative Code 194-37-070(5)(c)(i) and the methodology utilized by the Pacific Northwest Power and Conservation Planning Council.

District staff presented IRP analysis, including conservation results, to the Board of Commissioners a series of briefings throughout the IRP development. A copy of the Draft 2025 IRP was posted to the District's publicly accessible website at www.snopud.com/irp on October 13, 2025.

Based on its analysis, staff is recommending adoption of a two-year conservation target for the 2026-2027 biennium of 7.5 average megawatts, and a ten-year conservation potential estimate for the 2026-2035 period of 62.4 average megawatts, calculated at busbar.

Board consideration of adoption of the two-year conservation target for 2026-2027 and the ten-year conservation potential estimate for the 2026-2035 period is scheduled for December 16, 2025.

List Attachments:
Presentation

SNOHOMISH PUD
Energizing Life In Our Communities

Biennial Conservation Targets and Ten-Year Conservation Potential Estimate

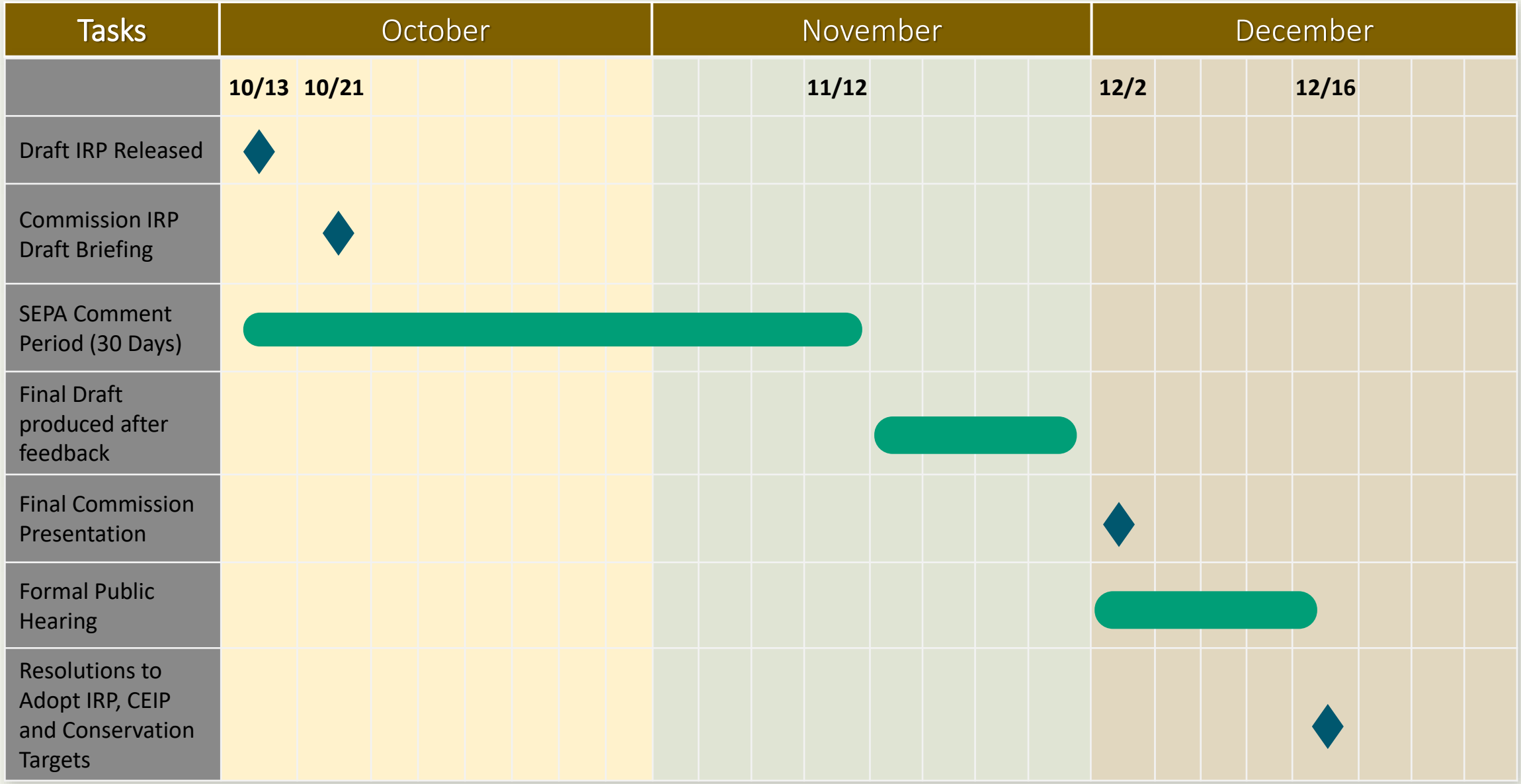
Jeff Feinberg, Senior Manager Energy Services & Customer Innovations
December 2, 2025
Prior Presentations – January 21, 2025, April 8, 2025, June 17, 2025, August 19, 2025, October 21, 2025

Agenda

- Context
- Biennial Conservation Targets
- Ten-Year Conservation Potential Estimate

This public hearing briefing is intended to allow for further public comment ahead of December 16, 2025, Board consideration of a Resolution to adopt conservation targets.

End of Year Timeline



Context

- The Energy Independence Act, Chapter 19.285 RCW, requires that the District formally adopt by Resolution two-year conservation targets and a ten-year conservation potential estimate, and submit them to the Washington State Department of Commerce on or before January 1, 2026.
- The PUD performs analysis for these targets in the Integrated Resource Planning (IRP) process.
- Staff have presented the targets in the course of IRP briefings, released the draft 2025 IRP with the targets on October 13, 2025, for public comment, and conducted a 31-day State Environmental Protection Act (SEPA) process that included opportunity for public comment and resulted in a Determination of Non-Significance.

Proposed Targets

- Conservation targets are derived from IRP analysis that solves for the lowest cost, lowest risk portfolio of resources to serve PUD customer load. Analysis can be found at www.snopud.com/irp.
- **2026-2027 Biennial Conservation Target:**
  - 7.5 average megawatts, calculated at busbar.
- **2026-2035 Ten-Year conservation Potential Estimate:**
  - 62.4 megawatts, calculated at busbar.

BUSINESS OF THE COMMISSION

Meeting Date: December 2, 2025 **Agenda Item:** 7A

TITLE:

Consideration of a Resolution Adopting the 2026 Budget for Public Utility District No. 1 of Snohomish County, Washington

SUBMITTED FOR: Public Hearing and Action

Finance Division	Sarah Bond	8448
Department	*Contact*	*Extension*

Date of Previous Briefing: November 18, 2025
Estimated Expenditure: Presentation Planned ☐

ACTION REQUIRED:

☒ Decision Preparation
☐ Policy Discussion
☐ Policy Decision
☒ Statutory
☐ Incidental (Information)
☐ Monitoring Report

SUMMARY STATEMENT:

Identify the relevant Board policies and impacts:

Governance Process, Board Job Description: GP-3(4) … a non-delegable, statutorily assigned Board duty as defined under RCW 54.16.080 … budget.

The attached Resolution adopts the 2026 Budget for the Electric, Generation and Water Systems.

List Attachments:
Resolution
Exhibit A

RESOLUTION NO. _____

A RESOLUTION Adopting the 2026 Budget for Public Utility District No. 1 of Snohomish County, Washington

WHEREAS, a proposed budget for Public Utility District No. 1 of Snohomish County, Washington (the "District"), was filed by the Commission of the District in accordance with the requirements of applicable law; and

WHEREAS, after having given prior notice to the public in accordance with the requirements of applicable law, the Commission held public hearings to take testimony on issues relating to spending levels under consideration for the year 2026; and

WHEREAS, Resolution No. 5853 Modifying the Electric System's Financial Reserve Policy provides that cash reserves and funds are presented in the annual budget and that the staff discuss with the Board proposed modifications of funds; and

WHEREAS, the Commission's Governance Policy on Executive Limitations specifically prohibits the General Manager from financial planning/budgeting which "plans for rate increases in excess of three percent (3%) in any year, or compound increases in excess of ten percent (10%) over any consecutive five-year period…" (Financial Planning and Budgeting (EL-4 (6)); and

WHEREAS, staff has provided public hearing presentations which demonstrate that inflation, market prices, supply chain delays, and other cost pressures have increased revenue requirements for the Water System, and the policy limitation was not met; and

WHEREAS, after having considered staff's estimates of income for 2026 and estimates of expenditures, capital construction requirements, and projected use of reserve funds, and having considered the public testimony of those customers submitting and offering

testimony, the Commission has concluded that the 2026 District budget summarized in Exhibit "A" hereto is fairly structured to maintain the financial health of the District and meet the needs of its customers.

NOW, THEREFORE, BE IT RESOLVED by the Commission of Public Utility District No. 1 of Snohomish County, Washington, as follows:

1. The EL-4 (6) limitation on planned rate increase percentages is hereby waived for this budget and forecasting cycle, and the 2026 budget and the fund transfers for Public Utility District No. 1 of Snohomish County, as summarized in the attached Exhibit "A," is hereby adopted.

   PASSED AND APPROVED this 2nd day of December 2025.

_____
President

_____
Vice-President

_____
Secretary

Exhibit A

Snohomish County PUD 2026 Budget

($000's)	Electric	Generation	Water
Operating Revenues			
Energy/Water Retail Sales	$ 766,866	$ 28,163	$ 18,069
Energy/Water Wholesale Sales	27,678	-	753
Other Operating Revenues	38,565	-	451
Total Operating Revenues	**$ 833,109**	**$ 28,163**	**$ 19,272**
Operating Expenses			
Purchased Power/Water	$ 317,905	$ -	$ 4,497
Operations & Maintenance	305,446	16,816	9,706
Taxes	47,761	98	941
Depreciation (non-cash)	71,116	6,222	3,927
Total Operating Expenses	**$ 742,229**	**$ 23,136**	**$ 19,072**
Net Operating Income	**$ 90,880**	**$ 5,028**	**$ 200**
Non-Operating Income (Expense)			
Interest Income & Other	$ 29,529	$ 977	$ 286
Interest Charges	(25,516)	(2,874)	(1,549)
Contributions	36,702	50	4,151
Total Non-Operating Income (Expense)	**$ 40,715**	**$ (1,846)**	**$ 2,889**
Net Income	**$ 131,595**	**$ 3,181**	**$ 3,089**
Other Expenditures			
Capital Expenditures	$ 248,975	$ 5,681	$ 21,268
Debt Service Principal	13,194	3,718	1,103
Reserves Additions/(Uses)			
Revenue Fund/GFC Fund	$ (7,996)	$ -	$ (10,028)
Bond Construction Funds	(59,200)	-	(6,648)

BUSINESS OF THE COMMISSION

Meeting Date: December 2, 2025 **Agenda Item:** 7B

TITLE

Consideration of a Resolution Amending the District's Water Service Rates and Charges for Single Family, Multiple Family, and Commercial/Industrial Customers for Water Utility Service

SUBMITTED FOR: Public Hearing and Action

Water Utility	Christina Arndt	3001
Department	*Contact*	*Extension*

Date of Previous Briefing: November 18, 2025
Estimated Expenditure: Presentation Planned ☐

ACTION REQUIRED:

☐ Decision Preparation
☐ Policy Discussion
☐ Policy Decision
☒ Statutory
☐ Incidental (Information)
☐ Monitoring Report

SUMMARY STATEMENT:

Identify the relevant Board policies and impacts:

Governance Process, Board Job Description: GP-3(4)(C)(1) a non-delegable, statutorily assigned Board duty – Rates/Fees. Establish and maintain rates and charges for electric energy and water and various other services, facilities, and commodities sold, furnished or supplied by the District.

Public Utility District No. 1 of Snohomish County (the "District") has full and exclusive authority under RCW 54.16.030 to regulate and control the use, distribution and price of its Water Utility services, and has the power and obligation under RCW 54.24.080, to establish, maintain, and collect rates or charges for water and other services supplied by the District which shall be fair, nondiscriminatory, and adequate to provide revenues sufficient for payment of its lawful obligations, to fund its planned improvements, and to provide quality water service to its existing and new water service customers.

On November 18, 2025, the District held a public hearing to review the Water Utility's projected plans and revenue needs and the proposed Water Utility general retail rate, and to provide District water service customers the opportunity to comment thereon.

The proposed rate increase is based on an in-depth review of the Water Utility's historical and projected revenues, expenses, growth rate, updates to the Water Utility's financial model, 20-year

capital improvement plan, cost-of-service analysis, and consideration of applicable issues impacting retail water rates since the last adjustment, including other factors driving the need for a rate increase.

Factors impacting the proposed increase include the continued emphasis on the replacement of aging water mains and other necessary capital improvements, supply chain issues driving increased costs associated with operations and maintenance, addition of new full time employees, maintaining fiscal policy targets, the phase-in of the recommended enhancement to days cash on hand, continued push to maximize the use of our Lake Stevens Treatment Plant, continued increase in administrative costs shared with Electric, and the adoption of the City of Everett Pass-Through Cost Adjustment on October 21, 2025, by Resolution 6247.

In addition, the detailed Cost of Service Analysis ("COSA") performed by District staff and Financial Consulting Solutions Group, Inc. a Bowman Company ("FCS Group") concluded that the District's Single Family, Multiple Family, and Commercial / Industrial customers are currently funding a proportionate share of the overall revenue requirements of the Water Utility and that the designated retail rate classes do not require a separate COSA adjustment to ensure the rate classes are paying for their fair share. Therefore, staff recommends applying the water general retail rate increase equally across the District's Single Family, Multiple Family, and Commercial/Industrial customers and continuing to re-evaluate through the completion of a COSA for each subsequent year.

Based on the analysis completed, including the in-depth COSA, and Board comments from the November 18, 2025, meeting District staff proposes a 5.75 percent retail water service rate increase for Single Family Residential, Multiple Family, and Commercial/Industrial customers effective January 1, 2026, to address the above factors. See Attachment 1 to this Cover Sheet.

Note: The water service general retail rate amendment for Commercial/Industrial customers applies to and will take effect through existing District Wholesale Water Agreements with Twin Falls/Seymours and Sudden View Water System/Illiad. See Exhibit A to Resolution, Table B-9.

If approved, the amended water service general retail rate for Single Family, Multiple Family, and Commercial/Industrial Customers (and Wholesale Water Service Customers) for water utility services will take effect on January 1, 2026.

List Attachments:

Resolution
Exhibit A – Redlined
Attachment 1
Presentation – Previously presented November 18, 2025

RESOLUTION NO. _____

A RESOLUTION Amending the District's Water Service Rates and Charges for Single Family, Multiple Family, and Commercial/Industrial Customers for Water Utility Service

WHEREAS, on December 5, 2017, the Board of Commissioners of Public Utility District No. 1 of Snohomish County, Washington, (the "District") adopted Resolution No. 5829, Amending the District's Water Utility Service Rates and Establishing Periodic Review of Water Utility Charges; and

WHEREAS, on February 4, 2025, the Commission adopted Resolution No. 6207, Amending the District's Water Service Rates and Charges for Single Family, Multiple Family, and Commercial/Industrial Customers for Utility Service, and the Commission now finds that such rates and charges need further amendment; and

WHEREAS, the District has full and exclusive authority under RCW 54.16.030 to regulate and control the use, distribution, and price of its Water Utility services, and the Commission has the power and obligation under RCW 54.24.080 to establish, maintain, and collect rates or charges for water and other services supplied by the District which shall be fair, nondiscriminatory, and adequate to provide revenues sufficient for payment of its lawful obligations, to fund its planned improvements, and to provide quality water service to its existing and new water service customers; and

WHEREAS, District staff with the assistance of Financial Consulting Solutions Group, Inc. a Bowman Company have reviewed and updated the Water Utility's financial model, 20-year capital improvement plan, cost-of-service analysis, and reviewed applicable issues impacting retail water rates since the last adjustment. Impacting factors include increases in the cost of purchased water from the City of Everett, continued

emphasis on the replacement of aging water mains and other necessary capital improvements, supply chain issues driving increased costs associated with operations and maintenance, maintaining fiscal policy targets, recommended enhancement to days cash on hand, continued push to maximize the use of the Lake Steven Treatment Plant and other necessary system infrastructure improvements, and continued increase in administrative costs shared across the District; and

WHEREAS, District staff have proposed, consistent with the cost-of-service analysis, a 5.75 percent general retail water service rate and charge increase for Single Family Residential, Multiple Family, and Commercial/Industrial customers effective January 1, 2026, to address the factors set forth above; and

WHEREAS, a 5.75 percent general retail water service rate and charge increase for Commercial/Industrial customers shall apply to Wholesale Water Service customers through existing District Wholesale Water Agreements, effective January 1, 2026; and

WHEREAS, on October 21, 2025, the Commission adopted Resolution No. 6247, Amending the District's Water Retail Rates and Charges to Pass Through City of Everett Purchase Water Cost Increase ("2026 City of Everett Pass Through"); and

WHEREAS, on November 4, 2025, the Commission Adopted Resolution No. 6250, Amending the District's Water Retail Rates and Charges to Repeal the Monthly Customer Charge and Adopt a Daily Base Charge ("Daily Base Charge"); and

WHEREAS, the rate amendments adopted under Resolution No. 6247, and Resolution No. 6250, are incorporated into Exhibit A to this resolution as the 2026 City of Everett Pass Through, the Daily Base Charge, and the 2026 General Retail Rate amendments proposed under this resolution all take effect on January 1, 2026; and

WHEREAS, on November 18, 2025, a public hearing was held to review the Water Utility's projected plans and revenue needs and the proposed Water Utility retail rates and charges, and to provide District water service customers the opportunity to comment thereon; and

WHEREAS, the Commission has considered the information and comments provided at such meeting; and

WHEREAS, the Commission finds that the proposed amendment of the District's Water Utility service rates and charges is consistent with the cost-of-service analysis, and is reasonable, proper and in the best interests of the District and its customers.

NOW, THEREFORE, BE IT RESOLVED by the Board of Commissioners of Public Utility District No. 1 of Snohomish County, as follows:

Section 1. The District's rates and charges for Water Utility service shall be amended as set forth in Exhibit "A," which Exhibit is attached hereto and incorporated herein by this reference.

Section 2. The rates and charges amendment hereby imposed shall become effective for the service described in such schedules, beginning on January 1, 2026, as provided in the attached Exhibit "A", and such rate and charge amendments shall remain in effect until further amended. All water consumption prior to January 1, 2026, shall be billed at the rates in effect prior to such date. In preparing customers' bills to implement this resolution on January 1, 2026, the District shall prorate such bills as if water consumption occurred at a constant rate during the billing period.

Section 3. Existing rates and charges not amended by this resolution shall remain in effect and unchanged. Any future proposed changes to Water Utility rates and charges will be periodically reviewed and approved by the Commission as necessary.

PASSED AND APPROVED this 2nd day of December, 2025.

_____
President

_____
Vice-President

_____
Secretary

EXHIBIT A

Effective January 1, 2026
Resolution No. XXXX

Table B-6
Water Service Rates and Charges - Single Family [1,2]

Description	Daily Base Charge	Commodity Rate	Unmetered Monthly Rate	Monthly Surcharge
General Rates and Charges	$~~0.94~~ 0.99	$~~4.34~~ 4.59/CCF	$~~71.84~~ 75.97	N/A
Special Rates and Charges				
Lake Roesiger [3]	$~~0.94~~ 0.99	$~~4.34~~ 4.59/CCF	$~~80.24~~ 84.37 [3]	N/A
Dubuque [5]	$~~0.94~~ 0.99	$~~4.34~~ 4.59/CCF	$~~81.84~~ 85.97 [4]	10.00 [5]
Booster Facilities [6]	$~~0.98~~ 1.04	$~~4.34~~ 4.59/CCF	N/A	N/A
T Marks/Joywood [7]	$~~0.94~~ 0.99	$~~4.34~~ 4.59/CCF	$~~101.84~~ 105.97 [4]	30.00 [7]
Kayak Estates Water System [8]	$~~0.94~~ 0.99	$~~4.34~~ 4.59/CCF	$~~91.84~~ 95.97 [4]	20.00 [8]
Cascade Acres [9]	$~~0.94~~ 0.99	$~~4.34~~ 4.59/CCF	$~~101.84~~ 105.97 [4]	30.00 [9]
Warm Beach [10]	$~~0.94~~ 0.99	$~~4.34~~ 4.59/CCF	$~~106.84~~ 110.97 [4]	35.00 [10]

Notes:
CCF = 100 Cubic Feet
N/A = Not Applicable

Footnotes:

[1] Single-family applications shall include single-family residential units; and duplexes and multiple-family residential customers with individual meters to each unit.

[2] Rates are subject to proportional increases to compensate for any gross revenue tax imposed by any municipal body upon the District.

[3] An additional charge of $0.84/CCF is charged to Lake Roesiger residents, for septic tank pumping.

[4] Includes monthly surcharge.

[5] Surcharge ends: July 1, 2026 (Refer to Resolution 4482)

[6] This schedule will be on limited accounts (see 2.3.11 Booster Facilities).

[7] Surcharge ends: August 1, 2028 for Joywood & March 1, 2018 for duplex units metered individually. (Refer to Resolution 5087)

[8] Surcharge ends: November 18, 2026 (Refer to Resolution 5271, plus delay due to actual ownership transfer date)

[9] Surcharge ends: December 31, 2034 (Refer to Resolution 5657)

[10] Surcharge ends: September 13, 2038 (Refer to Resolution 5864)

EXHIBIT A

Effective January 1, 2026
Resolution No. XXXX

Table B-7
Water Service Rates and Charges - Multiple Family [1,2]

Description	Daily Base Charge	Commodity Rate	Monthly Surcharge	Septic Pumping Charge
General Rates and Charges	$~~1.01~~ 1.07	$~~4.38~~ 4.63/CCF	N/A	N/A
Special Rates and Charges				
Lake Roesiger [4]	$~~1.01~~ 1.07	$~~4.38~~ 4.63/CCF	N/A	$0.84/CCF
Dubuque[3]	$~~1.01~~ 1.07	$~~4.38~~ 4.63/CCF	$10.00 [3]	N/A
West Machias [5]	$~~1.01~~ 1.07	$~~4.38~~ 4.63/CCF	$30.00 [5]	N/A
Kla-Ha-Ya [6]	$~~1.01~~ 1.07	$~~4.38~~ 4.63/CCF	$30.00 [6]	N/A
Kayak Estates Water System [7]	$~~1.01~~ 1.07	$~~4.38~~ 4.63/CCF	$20.00 [7]	N/A
Cascade Acres [8]	$~~1.01~~ 1.07	$~~4.38~~ 4.63/CCF	$30.00 [8]	N/A
Warm Beach [9]	$~~1.01~~ 1.07	$~~4.38~~ 4.63/CCF	$35.00 [9]	N/A

Notes:
CCF = 100 Cubic Feet
N/A = Not Applicable

Footnotes:

[1] Multiple-family applications shall include duplexes, triplexes, and other multiple-family residential customers of two units or more, metered through one meter.

[2] Rates are subject to proportional increases to compensate for any gross revenue tax imposed by any municipal body upon the District.

[3] Surcharge ends: July 1, 2026 (Refer to Resolution 4482)

[4] An additional charge of $0.84/CCF is charged to Lake Roesiger residents for septic tank pumping.

[5] Surcharge ends: November 1, 2025 (Refer to Resolution 5087)

[6] Surcharge ends: February 1, 2025 (Refer to Resolution 5087)

[7] Surcharge ends: November 18, 2026 (Refer to Resolution 5271, plus delay due to actual ownership transfer date)

[8] Surcharge ends: December 31, 2034 (Refer to Resolution 5657)

[9] Surcharge ends: September 13, 2038 (Refer to Resolution 5864)

EXHIBIT A

Effective January 1, 2026
Resolution No. XXXX

Table B-8
Water Service Rates and Charges - Commercial/Industrial [1,2]

Description	Daily Base Charge	Commodity Rate	Monthly Surcharge	Monthly Septic Pumping Charge
General Rates and Charges	$~~2.19~~ 2.32	$~~4.24~~ 4.48/CCF	N/A	N/A
Special Rates and Charges				
Lake Connor Park	$~~4.12~~ 4.36	$~~5.00~~ 5.29/CCF	N/A	N/A
Lake Roesiger [3]	$~~2.19~~ 2.32	$~~4.24~~ 4.48/CCF	N/A	$0.84/CCF
Kayak Estates Water System [4]	$~~2.19~~ 2.32	$~~4.24~~ 4.48/CCF	20.00 [4]	N/A
Warm Beach [5]	$~~2.19~~ 2.32	$~~4.24~~ 4.48/CCF	35.00 [5]	N/A

Notes:
CCF = 100 Cubic Feet
N/A = Not Applicable

Footnotes:

[1] Commercial or industrial occupants, including governmental and institutional occupants.

[2] Rates are subject to proportional increases to compensate for any gross revenue tax imposed by any municipal body upon the District.

[3] An additional charge of $0.84/CCF is charged to Lake Roesiger customers for septic tank pumping.

[4] Surcharge ends: November 18, 2026 (Refer to Resolution 5271, plus delay due to actual ownership transfer date)

[5] Surcharge ends: September 13, 2038 (Refer to Resolution 5864

EXHIBIT A

Effective January 1, 2026
Resolution No. XXXX

Table B-9
Wholesale Water Service [1,2]

Commodity Charge

City of Granite Falls	$2.25/CCF

Footnotes:

[1] Available only for wholesale water service for resale by a wholesale customer to its retail water customers.

[2] Rates are subject to proportional increases to compensate for any gross revenue tax imposed by any municipal body upon the District.

[3] Wholesale service to Granite Falls is subject to terms as defined in the Wholesale Water Agreement between the District and the City of Granite Falls, as amended from time to time.

Commodity Charge

City of Arlington [3,4]	$2.27/CCF [5]

Footnotes:

[1] Available only for wholesale water service for resale by a wholesale customer to its retail water customers.

[2] Rates are subject to proportional increases to compensate for any gross revenue tax imposed by any municipal body upon the District.

[3] Water will be supplied through one master meter.

[4] Wholesale service to Arlington is subject to terms as defined in the Wholesale Water Agreement between the District and the City of Arlington, as amended from time to time, including, but not limited to, Section 3 thereof.

[5] The actual rate for each year will be based on the average costs of the preceding year for each of the wholesale cost components as described in Exhibit 2 of the Wholesale Water Agreement with the City of Arlington.

Commodity Charge

City of Snohomish	$2.85/CCF

Footnotes:

[1] Available only for wholesale water service for resale by a wholesale customer to its retail water customers.

[2] Wholesale service to Snohomish is subject to terms as defined in the Wholesale Water Agreement between the District and the City of Snohomish, as amended from time to time.

EXHIBIT A

Effective January 1, 2026
Resolution No. XXXX

Table B-9
Wholesale Water Service [1,2]

	Daily Base Charge	Commodity Rate
Twin Falls/Seymours [3,4]	$~~2.19~~ 2.32	$~~4.24~~ 4.48/CCF [5]

Notes:
CCF = 100 Cubic Feet

Footnotes:

[1] Available only for wholesale water service for resale by a wholesale customer to its retail water customers.

[2] Rates are subject to proportional increases to compensate for any gross revenue tax imposed by any municipal body upon the District.

[3] Water will be supplied through one master meter.

[4] Wholesale service to Twin Falls/Seymours is subject to terms as defined in the Wholesale Water Agreement between the District and Twin Falls/Seymours, as amended from time to time, including, but not limited to, Section 2 thereof.

[5] The actual rate for each year will be based on the District's Water Commercial/Industrial Rate as described in Section 3 of the Wholesale Water Agreement with Twin Falls/Seymours.

	Daily Base Charge	Commodity Rate
Sudden View/Blue Rock Water Co./Iliad [3,4]	$~~2.19~~ 2.32	$~~4.24~~ 4.48/CCF [5]

Notes:
CCF = 100 Cubic Feet

Footnotes:

[1] Available only for wholesale water service for resale by a wholesale customer to its retail water customers.

[2] Rates are subject to proportional increases to compensate for any gross revenue tax imposed by any municipal body upon the District.

[3] Water will be supplied through one master meter.

[4] Wholesale service to Sudden View/Blue Rock Water Co./Iliad is subject to terms as defined in the Wholesale Water Agreement between the District and Sudden View/Blue Rock Water Co./Iliad, as amended from time to time, including, but not limited to, Section 2 thereof.

[5] The actual rate for each year will be based on the District's Water Commercial/Industrial Rate as described in Section 3 of the Wholesale Water Agreement with Sudden View/Blue Rock Water Co./Iliad.

ATTACHMENT 1

PROPOSED CHANGES TO THE DISTRICT'S WATER UTILITY RATES (Effective January 1, 2026)		
Description	**Current Rates**	**2026**
General Single-Family Residential - Table B-6		
General and Special Rates		
Daily Base Charge (per day)	$0.94	**$0.99**
Commodity Rate (per 100 cu ft)	$4.34	**$4.59**
Unmetered Monthly Rate	$71.84	**$75.97**
General Multi-Family Residential - Table B-7		
General and Special Rates		
Daily Base Charge (per day)	$1.01	**$1.07**
Commodity Rate (per 100 cu ft)	$4.38	**$4.63**
General Commercial / Industrial - Table B-8		
General and Special Rates, except Lake Connor Park		
Daily Base Charge (per day)	$2.19	**$2.32**
Commodity Rate (per 100 cu ft)	$4.24	**$4.48**
General Commercial / Industrial - Table B-8		
Lake Connor Park Daily Base Charge	$4.12	**$4.36**
Lake Connor Park Commodity Rate (per 100 cu ft)	$5.00	**$5.29**
General Commercial / Industrial - Table B-9		
Twin Falls / Seymours and Blue Rock Water Co. / Sudden View / Iliad		
Daily Base Charge (per day)	$2.19	**$2.32**
Commodity Rate (per 100 cu ft)	$4.24	**$4.48**

SNOHOMISH PUD

Energizing Life In Our Communities

2026 Water General Retail Rate Proposal

November 4, 2025

Presented by:

Christina Arndt – Manager, Water Utility

Purpose of the Presentation

Purpose

- To provide the Board the proposed 2026 Water General Retail Rates Adjustment.

Board Action Items

- No Action Required Today; this presentation is for information and discussion only.

Discussion Outline

- Background
- Drivers Impacting the Water Utility's 2026 Budget & Rates:
  - O&M
  - Capital
- Summary of Findings:
  - Revenue requirement
  - Cost-of-Service Analysis (COSA)
  - Rate design
- Water General Retail Rate Recommendation

2026 Water Budget Highlights & Rate Impacts

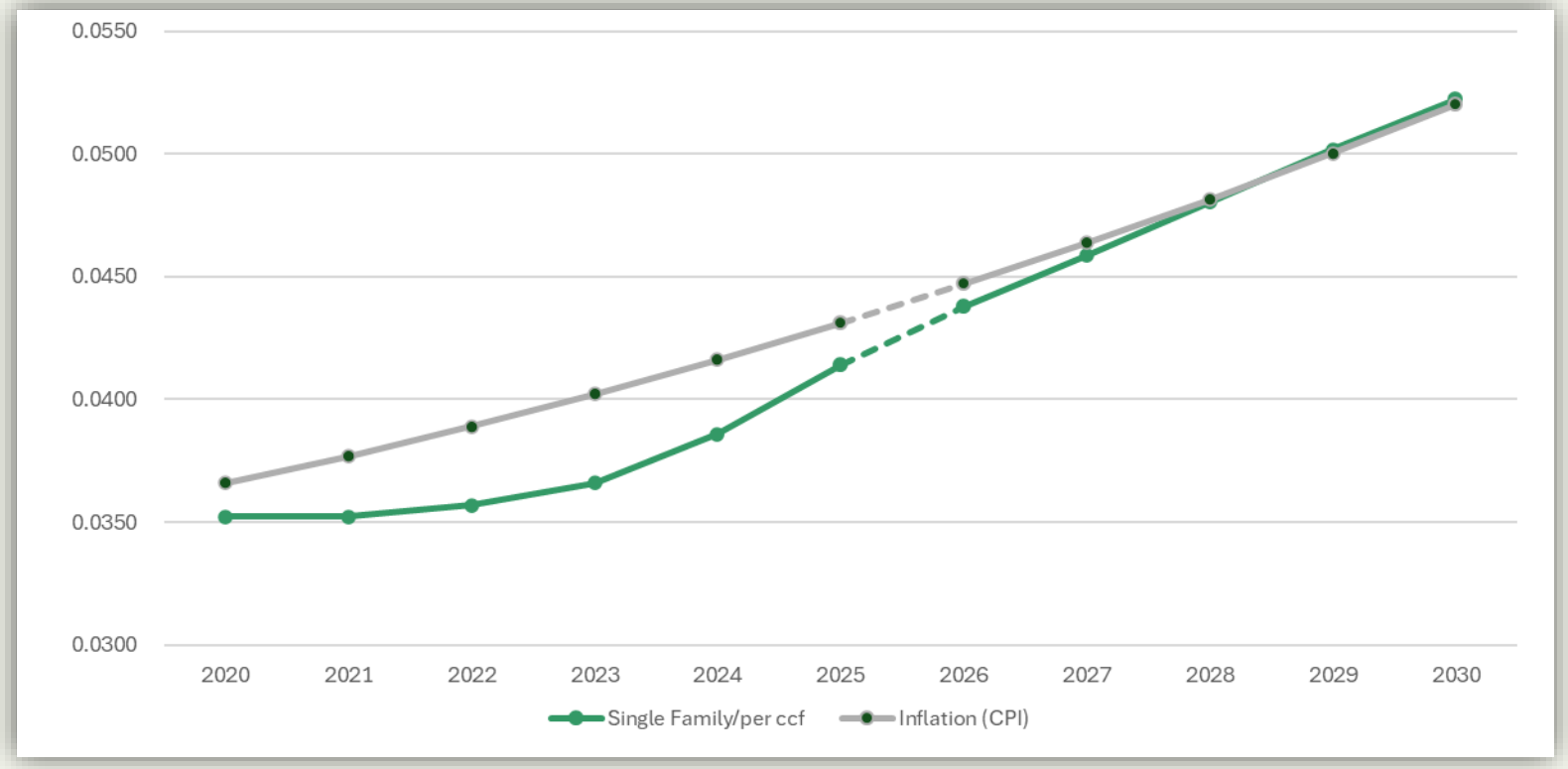


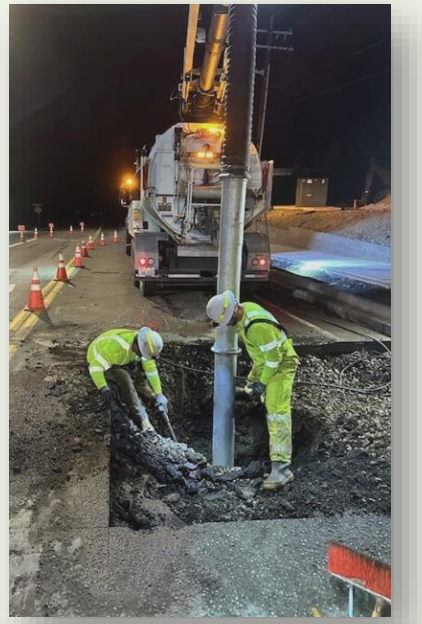




- Supply chain issues, inflation, regulatory requirements, and system growth driving increased costs.
- Labor cost increases (including shared services):
  - 2 New FTEs in 2026.
- Continued increase in administrative costs shared with Electric:
  - i.e.: HR, Accounting, IT, Legal, Facilities, etc.
- Continued increase in purchased water rates from City of Everett.
- Enhanced Water Utility fiscal policy targets:
  - Adjusted Days Cash on Hand (DCOH):
    - Multi-year progression to reach 150 DCOH by 2030.
- Bond Funded Projects = 31.25% of Capital.
- General Facilities Fund (GFC) Funded Projects = 54.62% of Capital.
- 5.75% Water General Retail Rate Proposed Adjustment.
- 2026 Bond Issuance = $11M.
- DCOH = 107 Target = 100.
- One Days Cash On Hand = $41,492.

Water Rates vs. Historical Inflation

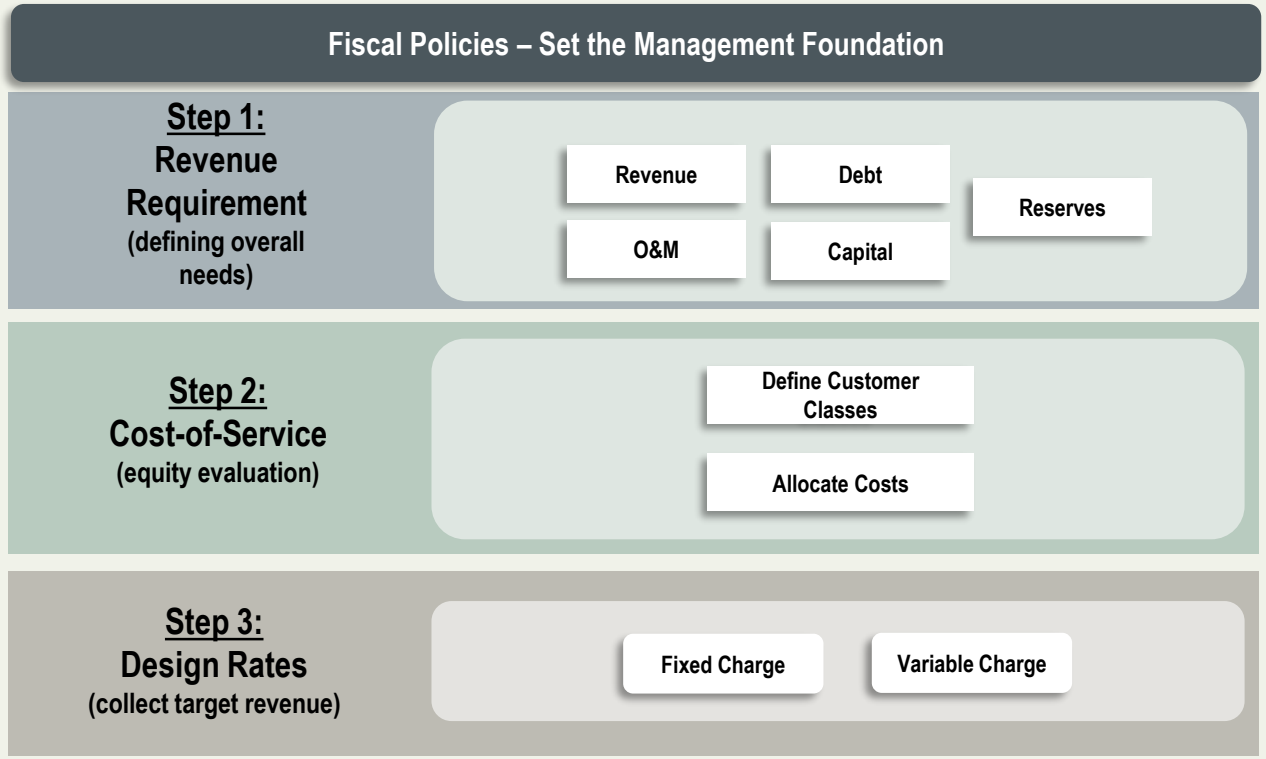






- Assumptions:
  - 5.75% Water General Retail Rate increase proposed.
  - 2.50% City of Everett Pass Thru approved for 2026.
  - 3.00-3.50% average inflation assumed from 2026-2030.

Overview of Rate Setting Process



Rate Strategy Guidelines & Forecast

Description	2026	2027	2028	2029	2030
Debt Issuance	$11.0M	$-	$-	$7.0M	$-
Days Cash on Hand Forecasted Est.	107*	108	117	127*	143
Days Cash on Hand Min Target	100	110	120	130	140
Debt Service Coverage (Target 1.75)	2.38x	2.36x	2.22x	2.24x	2.34x
Water General Retail Rate Adjustment	5.75%	4.80%	4.75%	4.50%	4.00%

Note: Years marked with an "*" indicate the years we anticipate bond issuances

- 2027-2030 shows rate increase projections.
- Increases are reviewed annually and will include updates to:
  - Revenue generation.
  - Expense trending.
  - Rate of new FTE hires.
  - Regulatory requirements.
  - Capital execution rates.

2026 Cost Reductions Impacting Rates



- No longer purchasing a 7-yard dump truck | $425K.
- Re-organized capital projects to better meet cash-flow timing, bond financing, and GFC related work.
- No longer moving forward on a new 4,000gal water tanker | $315K.
- Currently no longer moving forward with a Decant Facility | $3.5M over 3 years.
- Replacing the box on the 12-yard dump truck instead of replacing the entire truck | $30K vs. $417K.
- No longer replacing the 1-ton flatbed w/ crane | $151K.
- Deferred the replacement of a compressor | $30K.
- Deferred the Warm Beach drain field out to align with construction of the new reservoir | $20K.
- Outside Contracts vs. Internal Labor | $175K.
- Deferred Contract Easement Clearing / Maintenance | $20K.
- Deferred Steel Reservoir exterior cleaning / touchup | $30K.

Revenue Requirement & Rate Scenario

2026 Revenue Requirement		
Operating Expenses		
Purchased Water	$	4,497
Operating and Maintenance		9,706
Taxes		941
Revenue Funded Operating Expense	**$**	**15,145**
Capital Requirements		
Gross Capital Budget (less developer costs)	$	18,968
Principal and Interest on Debt		2,652
Use of GFC Funds		(9,317)
Use of Bond Proceeds		(6,648)
Revenue Funded Capital and Related Costs	**$**	**5,655**
Other Revenues		
Wholesale Sales revenues	$	753
Other Operating Revenues		1,268
Use of Operating Reserve		711
Other Revenues/Use of Reserves	**$**	**2,731**

=

Revenue Funded Operating Expense	$	15,145
Revenue Funded Capital and Related Costs		5,655
Other Revenues/Use of Reserves		(2,731)
2026 Budget Cash Requirements	**$**	**18,069**
Retail Revenue @ Current Rates	$	17,030
Additional Rate Revenue Required		1,039
Total Retail Revenue	**$**	**18,069**

Recommended Scenario	Existing	Proposed 2026	Forecasted 2027	2028	2029	2030
PUD Water General Retail Rate Component		*5.75%*	*4.80%*	*4.75%*	*4.50%*	*4.00%*
Proposed Increases		**5.75%**	**4.80%**	**4.75%**	**4.50%**	**4.00%**
Sample Residential Monthly Bill	$ 58.64	*$ 61.97*	*$ 65.88*	*$ 69.99*	*$ 74.19*	*$ 78.09*
$ Difference		*$ 3.33*	*$ 3.91*	*$ 4.11*	*$ 4.20*	*$ 3.90*

January 2026 Water General Retail Rate Recommendation

- Progress made towards rate equitability since initial 2018 adjustments.
- No Cost-of-Service changes recommended in 2026.
- Apply Water General Retail Rate adjustment equally to all classes of service:
  - Revisit COSA annually.

Rate Class	2026 Water General Retail Rate Increase
Residential / Single Family	5.75%
Multi Family	5.75%
Commercial / Industrial	5.75%

Forecasted Rate Schedule

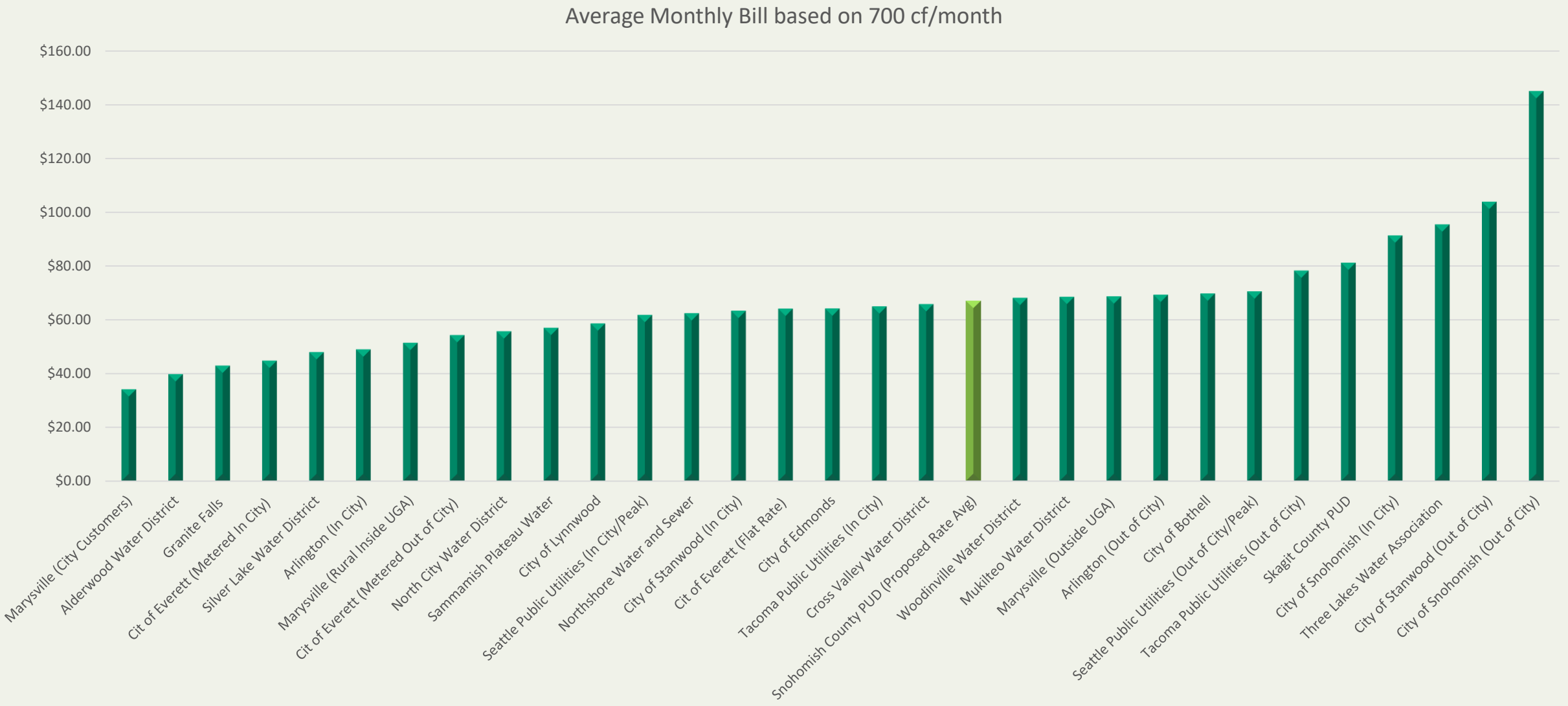
Description	Existing Rates	Proposed Rates 2026	Forecasted Rates 2027	2028	2029	2030
Single Family Residential						
Monthly Customer Charge	$ 28.33	$ 29.96	$ 31.85	$ 33.84	$ 35.87	$ 37.75
Commodity Rate (per 100 cu ft)	$ 4.34	$ 4.59	$ 4.87	$ 5.18	$ 5.49	$ 5.78
Multi Family Residential						
Monthly Customer Charge	$ 30.25	$ 31.99	$ 34.00	$ 36.13	$ 38.30	$ 40.31
Commodity Rate (per 100 cu ft)	$ 4.38	$ 4.63	$ 4.92	$ 5.23	$ 5.54	$ 5.83
Commercial / Industrial						
Monthly Customer Charge	$ 65.74	$ 69.52	$ 73.90	$ 78.52	$ 83.23	$ 87.60
Commodity Rate (per 100 cu ft)	$ 4.24	$ 4.49	$ 4.77	$ 5.07	$ 5.37	$ 5.65
Lake Connor Park						
Monthly Customer Charge	$ 123.59	$ 130.70	$ 138.94	$ 147.62	$ 156.48	$ 164.70
Commodity Rate (per 100 cu ft)	$ 5.00	$ 5.29	$ 5.62	$ 5.97	$ 6.33	$ 6.66

- Note:
  - All rates shown above include a range of 1.25% to 2.50% City of Everett (COE) Pass-Through for the years 2026-2030.

Sample Rate Impacts

Rate Impacts	Existing Rates	Proposed Rates 2026	Forecasted Rates 2027	2028	2029	2030
Single Family						
Average User- 7 ccf	$ 58.64	$ 61.97	$ 65.88	$ 69.99	$ 74.19	$ 78.09
Dif		*$ 3.33*	*$ 3.91*	*$ 4.11*	*$ 4.20*	*$ 3.90*
High User - 10 ccf	$ 71.64	$ 75.81	$ 80.59	$ 85.62	$ 93.70	$ 95.53
Dif		*$ 4.17*	*$ 4.78*	*$ 5.04*	*$ 8.08*	*$ 1.83*
Multi Family						
Low User - 10 ccf	$ 75.87	$ 78.27	$ 83.20	$ 88.43	$ 93.70	$ 98.61
Dif		*$ 2.41*	*$ 4.93*	*$ 5.23*	*$ 5.27*	*$ 4.91*
Average User - 20 ccf	$ 120.73	$ 124.56	$ 132.40	$ 140.73	$ 149.10	$ 156.91
Dif		*$ 3.83*	*$ 7.84*	*$ 8.33*	*$ 8.37*	*$ 7.81*
High User - 40 ccf	$ 210.45	$ 217.12	$ 230.80	$ 245.33	$ 259.90	$ 273.51
Dif		*$ 6.67*	*$ 13.68*	*$ 14.53*	*$ 14.57*	*$ 13.61*
Commercial						
Low User - 15 ccf	$ 132.63	$ 136.84	$ 145.45	$ 154.57	$ 163.78	$ 172.35
Dif		*$ 4.21*	*$ 8.61*	*$ 9.12*	*$ 9.21*	*$ 8.57*
Average User - 30 ccf	$ 197.87	$ 204.15	$ 217.00	$ 230.62	$ 244.33	$ 257.10
Dif		*$ 6.27*	*$ 12.85*	*$ 13.62*	*$ 13.71*	*$ 12.77*
High User - 60 ccf	$ 328.36	$ 338.77	$ 360.10	$ 382.72	$ 405.43	$ 426.60
Dif	*Dif*	*$ 10.41*	*$ 21.33*	*$ 22.62*	*$ 22.71*	*$ 21.17*

Rate Comparison



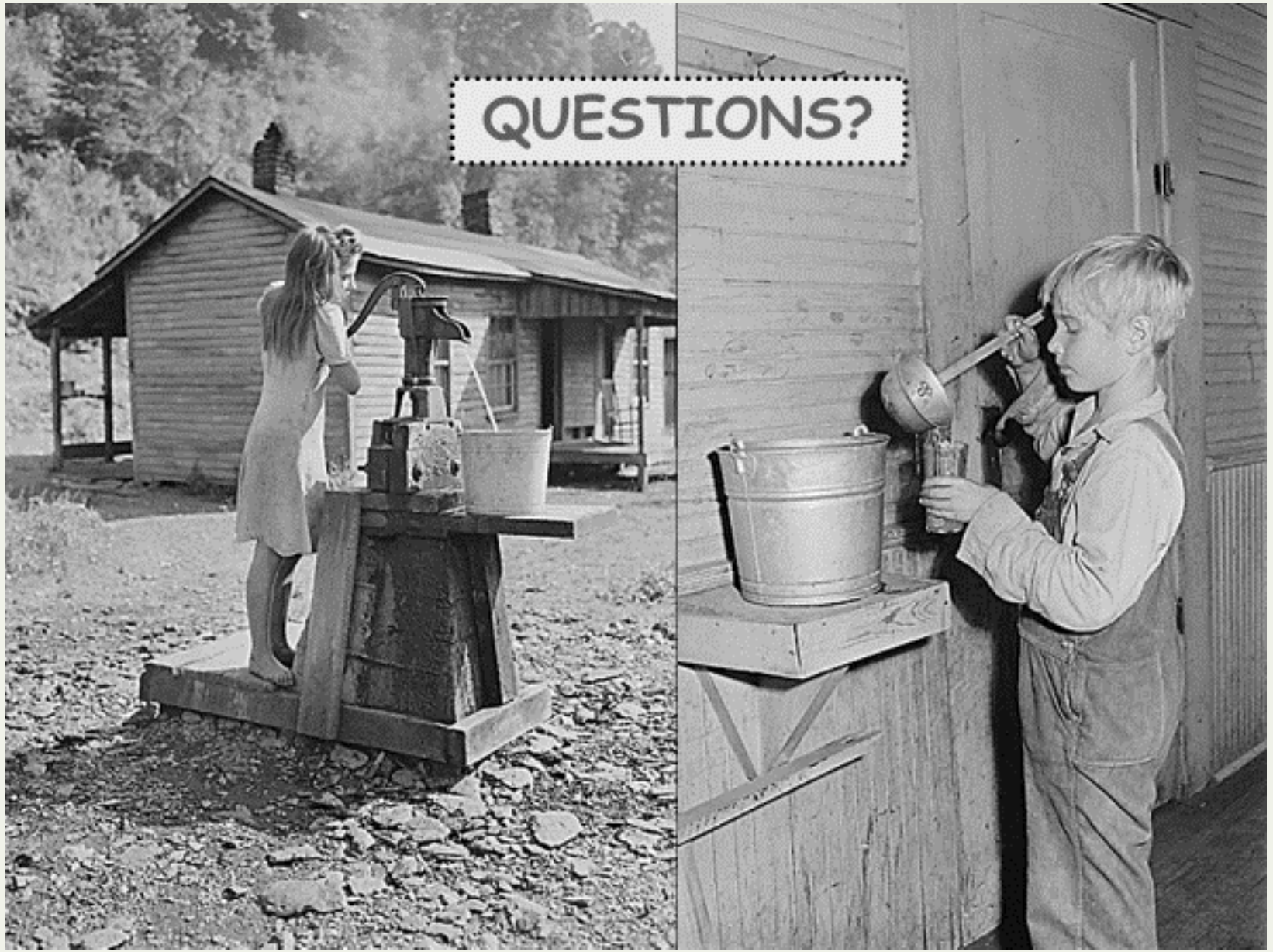
2026 Water General Retail Rate Recommendation



- Water General Retail Rate increase of 5.75% (Effective January 1, 2026).
- Rate increase applied equally for all classes of service.

Next Steps

- November 18, 2025 – Public Hearing 2026 Water Utility General Retail Rate Adjustment.
- December 2, 2025 – Board Action on 2026 Water Utility General Retail Rate Increase.
- January 1, 2026 – 2026 Water Utility General Retail Rates Take Effect.
- Continue to Revisit Cost-of-Service.
- Revisit Connection Charges, Fees, and Wholesale Rates in 2026.
- Revisit Conservation Rates at a Future Date.


QUESTIONS?

BUSINESS OF THE COMMISSION

Meeting Date: December 2, 2025 **Agenda Item:** 7C

TITLE

Consideration of a Resolution Approving Increased Fees Payable by Licensees of Space on District Utility Poles

SUBMITTED FOR: Public Hearing and Action

Rates, Economics, and Energy Risk Mgmt	Pete Dauenhauer	1762
Department	*Contact*	*Extension*

Date of Previous Briefing: November 18, 2025
Estimated Expenditure: _____ Presentation Planned ☐

ACTION REQUIRED:

☐ Decision Preparation
☐ Policy Discussion
☒ Policy Decision
☒ Statutory

☐ Incidental (Information)

☐ Monitoring Report

SUMMARY STATEMENT:

Identify the relevant Board policies and impacts:

Governance Process, Board Job Description, GP-3(4)(C)(1) a non-delegable statutorily assigned Board Duty to "[e]stablish and maintain rates and charges for electricity energy and water and various other services, facilities, and commodities sold, furnished, or supplied by the District."

Since 2008, RCW 54.04.045 has prescribed the cost allocation methodologies that locally controlled utilities in the State of Washington, including Public Utility District No. 1 of Snohomish County ("District"), must use in developing fees for third party wireline pole attachments. Per the statute, the District must develop non-discriminatory cost-based fees. Such fees are calculated by averaging the results of the Federal Communications Commission's Telecom methodology and the American Public Power Association's methodology.

District staff is proposing that the annual attachment fees for wholly-owned poles increase from $32.58 to $35.40 per attachment for 2026. Fees for jointly-owned poles would increase from $17.92 per attachment to $19.48 per attachment for 2026. The prior rate adjustment was approved in 2024. A number of factors can be attributed to this rate increase, including but not limited to the District's cost of poles, general and administrative expenses, and maintenance costs.

RECOMMENDATIONS/FUTURE ACTIONS:

Staff recommends that the District Board of Commissioners pass the attached resolution authorizing revision of the joint use fee schedule.

List Attachments:

Resolution
Exhibit A – Redlined
Presentation – Previously presented November 18, 2025

RESOLUTION NO. _____

A RESOLUTION Approving Increased Fees Payable by Licensees of Space on District Utility Poles

WHEREAS, Public Utility District No. 1 of Snohomish County ("District") enters into license and permit agreements ("License Agreements") with cable television system operators and others ("Licensees") granting the Licensees the nonexclusive right to use space on poles owned by the District for the purpose of attaching to such pole facilities and equipment used by the Licensees in connection with their operations; and

WHEREAS, the Application Fees, Contact Fees and Unauthorized Contact Penalty Fees (collectively “Fees”) that the District charges were established by resolutions passed by the District Board of Commissioners, including most recently Resolution No. 6197 (October 22, 2024); and

WHEREAS, RCW 54.04.045 defines the methodology for setting pole attachment fees by Public Utility Districts; and

WHEREAS, District staff proposed adjustment of said Fees in compliance with said state law for District Owned and Jointly Owned poles; and

WHEREAS, on November 18, 2025, the Commission held a hearing to consider any oral and written comments made by Licensees and members of the public with respect to the Fee adjustments proposed by District staff; and

WHEREAS, the Commission has reviewed the types and amounts of proposed Fees to be paid by Licensees and has considered the recommendations of staff regarding the same.

NOW, THEREFORE, BE IT RESOLVED by the Commission of Public Utility District No. 1 of Snohomish County that the Application Fees, Annual Contact Fees and Unauthorized Contact Penalty Fees to be paid for space on District utility poles on and after January 1, 2026, as set forth in the attached Exhibit "A," Joint Use Fee Schedule, are hereby adopted.

BE IT FURTHER RESOLVED that such Fees shall continue in effect unless and until modified by the Commission.

PASSED AND APPROVED this 2nd day of December, 2025.

_____
President

_____
Vice-President

_____
Secretary

Joint Use Fee Schedule
~~Effective January 1, 2025~~2026

Wireline Equipment Annual Contact Fees

Administrative & Engineering Review Fee: $~~340~~ 494 plus $~~22~~ 32 for each pole per application within the same Section, Township and Range.

Communication Cable (aerial rate)
Each contact fee provides six inches of vertical space on a pole and provides for a maximum of 2" cross section of cable/messenger diameter. Additional pole space required to provide minimum clearances per Exhibit "C" or cables of large diameter will result in additional contact fees.

Wholly-owned District Pole (a pole solely owned by the District):

~~$30.93 per contact (effective through December 31, 2024)~~
$32.58 per contact (effective January 1, 2025)
$35.40 per contact (effective January 1, 2026)

Jointly-owned Pole (a pole jointly owned by the District and another owner):

~~$17.01 per contact (effective through December 31, 2024)~~
$17.92 per contact (effective January 1, 2025)
$19.48 per contact (effective January 1, 2026)

Auxiliary Equipment (non-aerial rate)
Each contact fee provides one foot of vertical space on the pole. Equipment requiring more than one vertical foot of space on the pole will be charged additional contact fees. Power supplies, junction cabinets, and splice boxes are considered auxiliary equipment. Power supplies, for example, require an average of 2 feet of space per attachment.

Wholly-owned District Pole:

~~$30.93 per contact/foot (effective through December 31, 2024)~~
$32.58 per contact/foot (effective January 1, 2025)
$35.40 per contact/foot (effective January 1, 2026)

Jointly-owned Pole:

~~$17.01 per contact/foot (effective through December 31, 2024)~~
$17.92 per contact/foot (effective January 1, 2025)
$19.48 per contact/foot (effective January 1, 2026)

Unauthorized Contact Penalty (Bootleg)
$370.00 bootleg application fee per pole and 5 (five) years back rent at current wholly-owned District pole rate.

Wireless Telecommunications Equipment Annual Contact Fees
~~(Formerly Known as 'Exhibit "A"')~~

The following sets forth the ranges of Annual Fees (unless otherwise specified) for the use of various types of District property and facilities for installation of wireless telecommunications equipment or

facilities used for providing FCC-licensed frequencies, on a per-site basis.

Where a range of fees rather than a fee certain is provided, the actual fee for each site or other use of District facilities will be negotiated between the District and the Licensee or user based on the current and projected values of the following factors, to the extent applicable at the time the applicable site license agreement is executed by the District and the Licensee: location and other site-specific factors; height requirements for proposed Licensee equipment; amount of space used, or rendered unusable by others; the length of the proposed license term, in light of the then-current market conditions; the aggregate number of sites proposed to be licensed by the Licensee; and any other factors affecting the interests of the District, in the sole discretion of the District.

1. Use of unimproved space on District property for construction and/or installation of Licensee antennae support structures, antennae and related facilities:
(a) $8,000 to $12,000 per initial 1,000 square feet (or portion thereof); and
(b) Prorated amount of base fee for square footage in excess of 1,000 square feet used or rendered unusable to others.

2. Attachment of Licensee equipment or facilities to existing District facilities:
(a) Macro antennas on distribution poles above the electrical space: $4,000 to $8,000 per pole.
(b) Small cell (5G) antennas within the communication space or on Street Light standards: One-time application fee of $100 dollars plus ongoing annual contact fee of $148.50 or $270 per pole, depending on whether the pole is wholly or jointly owned and what arrangements for revenue-sharing have been made among the owners.
(c) Equipment on District poles in the Electrical Space or on Street Lights: $60 to $125 per installation.
(d) Rack space in District communications shelters: $235 to $500 per vertical unit.
(e) Other facilities: $4,000 to $14,000 plus a fee for usable square footage of $100 to $500 per square foot.
(f) Unimproved ground space for use for equipment shelters and other facilities serving installations described in subsections 2(a) and (c) above: $25 to $75 per square foot.

SNOHOMISH PUD
Energizing Life In Our Communities

2026 Pole Attachment Rates

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November 4, 2025

Previous Presentation: September 17, 2024

Purpose and Expectations

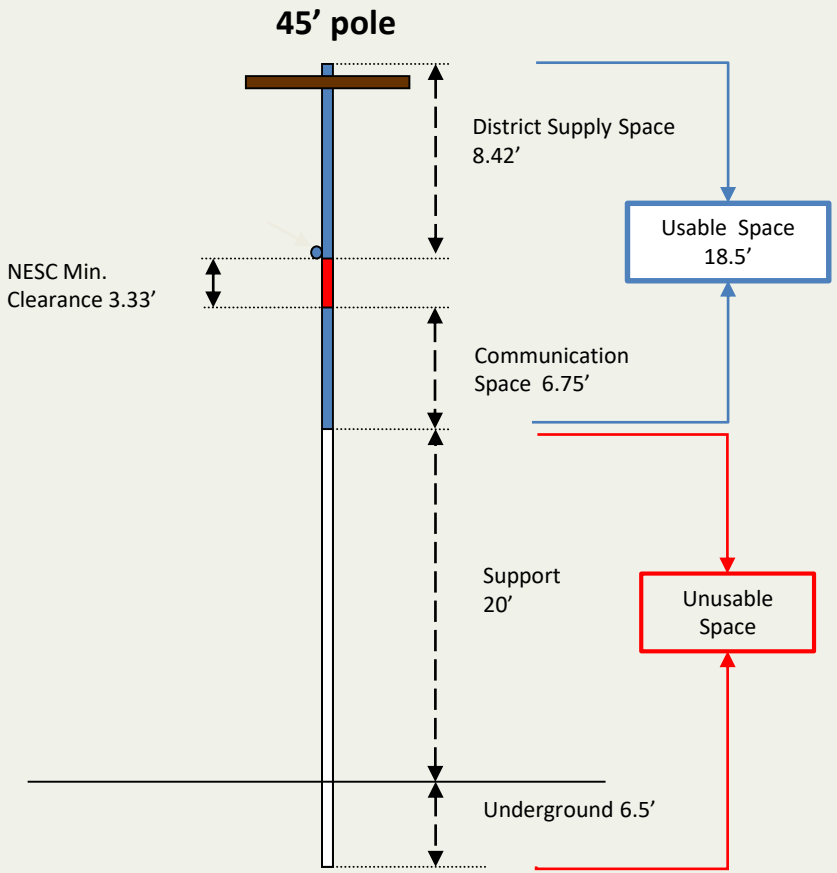
- The purpose of this presentation is to update the Commission on the new pole attachment rates that will go into effect January 1, 2026.
- November 18, 2025 – Public Hearing.
- December 2, 2025 - Public Hearing & Action.

Background

- The District currently has 87,964 attachments:
  - 28,911 on District owned poles
  - 59,053 on Jointly owned poles (District's share: 55%)
  - Approx. $2M of revenue in total
- 2024 Rate increase was 5%:
  - $1.54 (District Owned) and $0.85 (Jointly Owned) increase

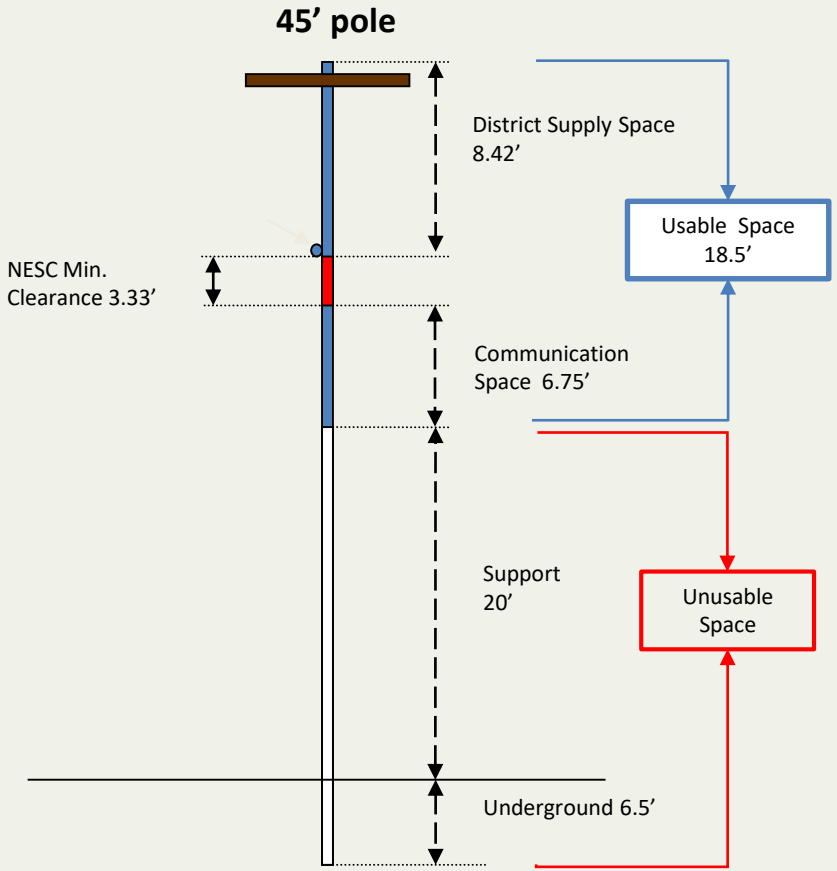
Rate Methodology

- Washington State Method - RCW 54.04.045:
  - Enacted June 2008.
  - 50% Federal Communications Commission (FCC) Telecom Method:
    - Formula only considers usable space of the pole.
    - Intended to provides subsidies for cable attachments to foster growth.
  - 50% American Public Power Association (APPA) Shared Cost Method:
    - Equal allocation of common space.



Snohomish Assumptions

- Space Occupied:
  - Standard FCC & APPA assumptions use 1 linear foot per attachment.
  - District and attachers have agreed to use ½ linear foot to allow for more attachments.
  - This reduces the attachment rate.
- Pole Size:
  - Standard FCC & APPA assumptions use 37.5ft.
  - District uses 45ft.
  - This reduces the attachment rate.
- Safety Space:
  - District did <u>not</u> factor the National Electrical Safety Code (NESC) Safety Space of 3.33ft as 'Unusable Space' -- prior agreement with customers.
  - This reduces the attachment rate.

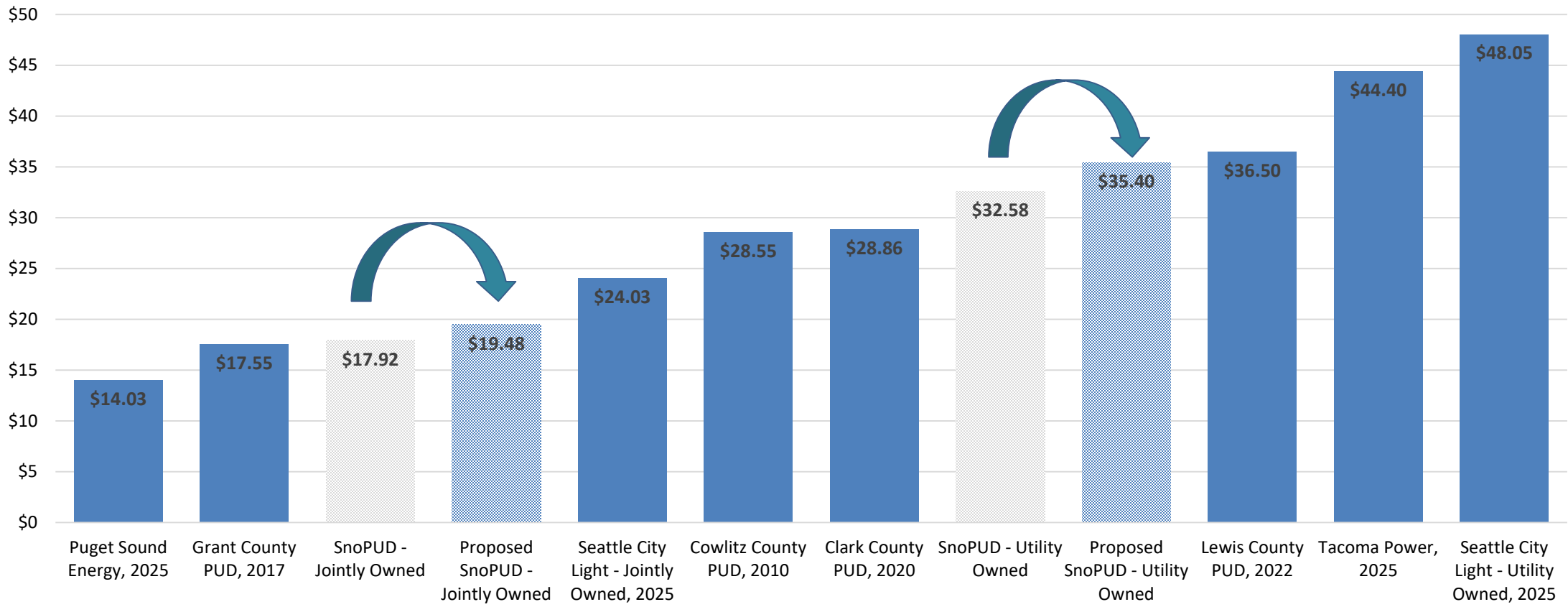


New Rates

	DISTRICT OWNED POLES (annual per attachment)	JOINTLY OWNED POLES (annual per attachment)
Current Rate	$32.58	$17.92
Proposed Rate	$35.40	$19.48
% Change	9%	9%

- Increase due to:
  - Cost of poles – 5%
  - A&G expenses – 17%
  - Maintenance – 13%
- Expected annual revenue increase: $212k
- Attachers were notified of rate increase on July 1, 2025

Rate Comparison



Next Steps

- Public Hearing: November 18, 2025
- Public Hearing & Action: December 2, 2025
- Rates Effective: January 1, 2026

BUSINESS OF THE COMMISSION

Meeting Date: December 2, 2025 **Agenda Item:** 7D

TITLE:

Consideration of a Resolution Amending the District's Retail Electric and Street Lighting Service Rate Schedules

SUBMITTED FOR: Public Hearing and Action

Rates, Economics, and Energy Risk Mgmt	Peter Dauenhauer	1762
Department	*Contact*	*Extension*

Date of Previous Briefing: November 18, 2025
Estimated Expenditure: Presentation Planned ☐

ACTION REQUIRED:

☐ Decision Preparation
☐ Policy Discussion
☒ Policy Decision
☒ Statutory
☐ Incidental (Information)
☐ Monitoring Report

SUMMARY STATEMENT:

Identify the relevant Board policies and impacts:

Governance Process, Board Job Description GP-3(4)(C)(1), a non-delegable, statutorily assigned Board duty: Rates/Fees. Establish and maintain rates and charges for electric energy and water and various other services, facilities, and commodities sold, furnished or supplied by the District.

The District 2026 budget process identified the need for an increase in retail revenue of 2.5% starting in April 2026. Over the projected rate period of April 1, 2026, to March 31, 2027, this represents $18.8 million in additional revenue.

After a series of briefings before the Commission on September 9, 2025, October 6, 2025, and November 4, 2025, District staff propose a 2.5 % system average revenue adjustment as a 2.8% increase for the Residential class (Schedule 7), 1.2% increase for the General Service Medium class (Schedule 20), 1.9% increase for the General Service Small class (Schedule 25), 4.0% increase for the Large Primary Service class (Schedule 36), and a 8.7% increase for the Special Continuous Service class (Schedule 23).

District staff also propose a rate redesign of the Large 115 kV Service (Schedule 38) that will not result in a revenue increase because no customers are on the rate schedule.

Further, District staff propose a 11.5% system average revenue adjustment for the street lighting service rates.

List Attachments:

Resolution
Exhibit A – Redline
Presentation – Previously Presented Novermber 18, 2025

RESOLUTION NO. _____

A RESOLUTION Amending the District's Retail Electric and Street Lighting Service Rate Schedules

WHEREAS, Public Utility District No. 1 of Snohomish County (the "District") staff have reviewed applicable issues potentially impacting wholesale and retail electric rates and street lighting service rates since the last rate adjustment, including but not limited to ongoing expenses related to supply chain issues, the District's recent decision to switch energy products with the Bonneville Power Administration, and general inflation; and

WHEREAS, District staff also has considered additional factors that create rate pressure, such as a forecast for continued budget deficits in upcoming years, the potential for negative consequences for failure to maintain healthy debt coverage amounts, future legislative and regulatory mandates dealing with climate change, and other energy and environmental initiatives, the impacts of electrification; and unforeseeable weather events; and

WHEREAS, District staff have proposed a 2.5 percent system average revenue adjustment to the District's retail electric rates to address the factors set forth above; and

WHEREAS, District staff reviewed applicable issues potentially impacting system street lighting service rates since the last adjustment, including but not limited to increases in power costs, general inflation, and the cost of goods over that time period; and

WHEREAS, District staff have proposed an 11.5 percent system average revenue adjustment to the District's street lighting service rates to address the factors set forth above; and

WHEREAS, a properly noticed meeting to consider the proposed rate adjustment was held on November 4, 2025, and a properly noticed public hearing to consider the proposed rate adjustment was opened on November 18, 2025; and

WHEREAS, the Board of Commissioners, having reviewed and considered information, testimony and evaluation presented and received at its public hearing, has determined that it would be in the best interest of the District and its electric utility customers that the District's (i) retail electric rates should increase by 2.5 percent on a system average basis on April 1, 2026, and (ii) street lighting service rates should increase by 11.5 percent on a system average basis on April 1, 2026, to achieve a reasonable balance between the needs of the District's customer/owners for stable rates while firmly maintaining the District's financial stability.

NOW, THEREFORE, BE IT RESOLVED by the Commission of Public Utility District No.1 of Snohomish County, as follows:

The District's Retail Electric Rate Schedule Nos. 7, 20, 20EV, 23, 25, 36, 38, and 201 and the District’s Street Lighting Service Rate Schedule Nos. 1, 3, 4, and 5 shall be revised as attached hereto as Exhibit A and incorporated herein by this reference, effective April 1, 2026.

PASSED AND APPROVED this 2nd day of December, 2025.

_____
President

_____
Vice-President

_____
Secretary

ELECTRIC UTILITY RATES

Schedule 7	Residential Service
Schedule 20	General Service, Medium Load
Schedule 20EV	Public Electric Vehicle Chargers
Schedule 23	Special Continuous Service
Schedule 24	Time of Use
Schedule 25	General Service, Small Load
Schedule 36	Large Primary Service
Schedule 37	New Large Single Loads
Schedule 38	Large 115kV Service
Schedule 50	Market-based Service
Schedule 80	Renewable Energy Credit Program
Schedule 82	Adjustments, Terms and Conditions of Service and Limitations of Liability
Schedule 83	PUD Retail Electric Vehicle Charging
Schedule 90	Facilities Smaller than 100 kW
Schedule 200	Net Metering Program
Schedule 201	Net Billing
Schedule 210	Demand Exchange

SCHEDULE 7 – RESIDENTIAL SERVICE

(1) AVAILABILITY: This schedule ("Schedule") is available in all territory served by the PUD for residential service. To be eligible for residential service, a facility must have no more than two dwelling units on a single meter and all facilities or structures must be related to or intended for human habitation. This schedule is also available for incidental farm service when used in conjunction with such residential service on the same premises. The following rates will be in effect through the dates indicated below, unless amended by the Commission.

(2) TYPE OF SERVICE: Sixty-hertz alternating current. The PUD reserves the right of final determination of voltage and phase of service.

(3) RATE: The monthly billing shall be the sum of the Base Charge and Energy Charge. Charges are calculated on a "per meter" basis. Each retail meter or billing installation shall be individually subject to the below charges.

Base Charge per day:

Effective Date	April 1, 2024	April 1, 2025
Small Service~~day~~	$0.36	$0.49
Medium Service~~day~~	$0.59	$0.80
Large Service ~~day~~	$0.84	$1.14
Extra-Large Service~~day~~	$1.37	$1.86

- **Small Service:**
  - Multifamily units
  - Services with panel sizes of 100 amps or less, or;
  - Supplemental "Add-on" services with panel sizes of 200 amps or less that are located on the same or contiguous parcels as a Schedule 7 dwelling unit billed to the same customer. Such services provide electricity to facilities that are used in conjunction with residential service but are not intended for human habitation such as garages, barns, or well pumps.
- **Medium Service**: Services with panel sizes of up to 200 amps and services connected prior to April 1, 2022 that do not qualify as Small Services.
- **Large Service:** Services with panel sizes greater than 200 amps and less than 401 amps.
- **Extra Large Service:** Services with panel sizes greater than 400 amps.

Energy Charge per kWh:

Effective Date	~~November 1, 2023~~	April 1, 2024	April 1, 2026
per kWh	~~$0.10279~~	$0.10263	$0.10613

(4) ADJUSTMENTS, LIMITATIONS OF LIABILITY, AND ADDITIONAL TERMS OF SERVICE: Service under this schedule is subject to the limitations on liability and other terms and conditions of service specified in the PUD's electric service regulations and rate schedule 82.

(5) TAX ADDITIONS: The above rates are subject to proportional increases to compensate for any gross revenue tax imposed by any municipal body or other governmental body having jurisdiction upon the PUD.

(6) BPA COST ADJUSTMENT: From time to time the Bonneville Power Administration ("BPA") adjusts its wholesale power and transmission rate to the PUD. At the discretion of the Commission, the rates in this Schedule may be adjusted to reflect BPA rate adjustments, either up or down, on the same date the BPA rate changes become effective. The adjusted rate will be developed by incorporating the BPA cost change into the Electric Cost of Service Model and rate design policies adopted by the Commission in the most recent rate proceeding.

(7) BPA RESIDENTIAL EXCHANGE BENEFITS: BPA is authorized to offer Residential Exchange benefits to eligible utilities, which benefits must be passed through to the utility's residential and small farm customers. To the extent the PUD obtains Residential Exchange benefits in any given BPA rate period, the rates in this Schedule will be adjusted by applying credits that reflect the benefits the PUD receives.

Effective Date: April 1, 2026~~5~~

[Res. No. 6205 (2025); History: 6167 (2024); 6144 (2023); 6103 (2023); 6046 (2022); 6028 (2021); 6002 (2021); 5940 (2019); 5927 (2019); 5822 (2017); 5806 (2017); 5735 (2015); 5728 (2015); 5708 (2015); COLA (2015); COLA (2014); 5639 (2013); 5626 (2013); 5574 (2012); COLA (2013); COLA (2012); 5553 (2011); 5470 (2009); 5450 (2009); 5440 (2009); 5418 (2009); COLA (2009); 5339 (2008); 5067 (2002); 5043 (2002); 5011 (2001); 4973(2001); 4963 (2000); 4925 (2000); 4861 (1999); 4848 (1999); 4835 (1999); 4774 (1998); 4666 (1997); 4600 (1997); 4532 (1996); 4366 (1995); 4146 (1994); 4010 (1993);3984 (1993); 3908 (1993); 3826 (1992); 3644 (1991); 3405 (1990); 3386 (1990); 3284 (1989); 3283 (1989); 3281 (1989); 3169 (1988); 3104 (1987); 2969 (1986); 2881 (1985); 2879 (1985); 2806 (1984); 2726 (1983); 2715 (1983); 2704 (1983); 2684 (1983); 2644 (1982); 2528 (1981); 2509 (1981); 2459 (1981); 2445 (1980); 2442 (1980); 2436 (1980); 2426 (1980); 2345 (1979); 2202 (1978); 1996 (1975); 1392 (1966); 1371 (1966); 795 (1957)]

SCHEDULE 20 – GENERAL SERVICE, MEDIUM LOAD

(1) AVAILABILITY: This schedule ("Schedule") is available in all territory served by the PUD for commercial, industrial, governmental, institutional, agricultural, and multiple residential customers whose actual Billing Demand was at least 100 kW once during the most recent twelve consecutive months, or whose estimated future Billing Demand, as estimated by the PUD, is at least 100 kW for one or more months during the twelve consecutive months following commencement of service under this schedule, or whose actual energy usage was at least 30,000 kWh per month once during the most recent twelve consecutive months. This schedule is not available to "New Large Single Loads" as defined in Rate Schedule 37. Such loads shall be served under Rate Schedule 37 - New Large Single Loads.

(2) TYPE OF SERVICE: Service is sixty Hertz alternating current delivered to one Point of Delivery. The PUD reserves the right of final determination of voltage and phase of service. Where mutually agreeable to the customer and the PUD, and at the option of the PUD, as indicated in Section 3.5 of the Customer Contract, service may be metered on the primary side of the distribution transformer.

(3) CUSTOMER CONTRACT: The PUD may, in its sole discretion, require the Customer to execute a contract (the "Customer Contract") as a condition of receiving service under this Schedule if the Customer receives service from the PUD at the primary voltage level, where the PUD has provided special undertakings to the Customer, or in other circumstances where the PUD judges that a contract may be prudent. Unless otherwise specified in the Customer Contract, such contract will commence on its effective date and will, unless earlier terminated in accordance with the provisions of the Customer Contract, continue until such time as the Customer no longer receives service under this Schedule or the Customer Contract is terminated by mutual agreement of the PUD and the Customer.

(4) RATE: The monthly billing shall be the greater of: (i) the sum of the Base Charge, Demand Charge and Energy Charge; or, (ii) the Minimum Charge. Charges are calculated on a "per meter" basis. Each retail meter or billing installation shall be individually subject to the below charges. All rates are subject to adjustments pursuant to Rate Schedule 82.

Base Charge per day:

Effective Date	~~April 1, 2023~~	April 1, 2024	April 1, 2026
Base Charge (per day)	~~$1.35~~	$2.10	$4.85

Energy Charge per kWh:

Effective Date	April 1, 2024	April 1, 2025
First 30,000 kWh	$0.09000	$0.08365
Over 30,000 kWh (July – March)	$0.08012	$0.08365
Over 30,000 kWh (April – June)	$0.06012	$0.08365

Demand Charge per kW of Billing Demand:

Effective Date	~~November 1, 2023~~	April 1, 2024	April 1, 2026
Billing Demand Up to 100 kW	~~N/A~~	N/A	N/A
Billing Demand Over 100 kW	~~$6.76~~	$7.16	$7.21

Billing Demand shall be equal to the maximum 15-minute demand measured during the billing period.

Minimum Charge:

Effective Date	April 1, 2023	April 1, 2024
Daily charge	$1.52 / day	$2.27 per day
Additional daily charge for all connected load > 10 kW	$.01707 per kW / day	$.01707 per kW per day

(5) ADJUSTMENTS, LIMITATIONS OF LIABILITY, AND ADDITIONAL TERMS OF SERVICE: Service under this schedule is subject to the limitations on liability and other terms and conditions of service defined in the PUD's electric service regulations and Rate Schedule 82.

(6) TAX ADDITIONS: The above rates are subject to proportional increases to compensate for any gross revenue tax imposed by any municipal body or other governmental body having jurisdiction upon the PUD.

(7) TRANSFER TO OTHER RATE SCHEDULES: A customer receiving service under this rate schedule whose electric power usage falls below the usage criteria in Section (1) above shall be transferred to another Rate Schedule for which it qualifies as soon as is practical. Upon the expiration of the Term or earlier termination of any of the Customer Service Documents for any reason, the Customer shall, if it requires continued electric service, commence taking service under the then-applicable retail tariff prescribed by the PUD for firm service to customers in its class; provided, however, that any such service shall be subject to availability.

(8) BPA COST ADJUSTMENT: From time to time the Bonneville Power Administration ("BPA") adjusts its wholesale power and transmission rates to the PUD. At the discretion of the Commission, the rates in this Schedule may be adjusted to reflect BPA rate adjustments, either up or down, on the same date the BPA rate changes become effective. The adjusted rate will be developed by incorporating the BPA cost change into the Electric Cost of Service Model and rate design policies adopted by the Commission in the most recent rate proceeding.

Effective Date: April 1, 2026~~5~~

[Res. No. 6205 (2025); History: 6167 (2024); 6144 (2023); 6103 (2023); 6046 (2022); 6028 (2021); 5979 (2020); 5927 (2019); 5806 (2017); 5806 (2017); 5735 (2015); 5708 (2015); 5639 (2013); 5626 (2013); 5574 (2012); 5553 (2011); 5470 (2009); 5450 (2009); 5440 (2009); 5418 (2009); 5043 (2002); 5023 (2001); 5011 (2001); 4963 (2000); 4835 (1999); 4848 (1999); 4600 (1997); 4010 (1993); 3908 (1993); 3405 (1990); 3386 (1990); 2879 (1985); 2726 (1983); 2704 (1983); 2684 (1983); 2644 (1982); 2509 (1981); 2445 (1980); 2442 (1980); 2345 (1979); 2202 (1978); 1996 (1975); 1392 (1966); 1371 (1966); 795 (1957)]

SCHEDULE 20EV – PUBLIC ELECTRIC VEHICLE CHARGERS

(1) AVAILABILITY: This schedule ("Schedule") is available in all territory served by the PUD for publicly available electric vehicle charging equipment that is metered separately from other loads not primarily associated with the charging of electric vehicles and whose total connected load is at least 100 kW and no greater than 5 MW.

Participation in this rate schedule is optional and eligible customers may choose to participate at any time. Customers who transfer from this rate schedule will not be eligible to participate for a 12-month period following the date of their exit. This rate schedule shall expire December 31, 2030, and all customers served by this schedule shall be transferred pursuant to Section 7.

(2) TYPE OF SERVICE: Service is sixty Hertz alternating current delivered to one Point of Delivery. The PUD reserves the right of final determination of voltage and phase of service. Where mutually agreeable to the customer and the PUD, and at the option of the PUD, as indicated in Section 3.5 of the Customer Contract, service may be metered on the primary side of the distribution transformer.

(3) CUSTOMER CONTRACT: The PUD may, in its sole discretion, require the Customer to execute a contract (the "Customer Contract") as a condition of receiving service under this Schedule if the Customer receives service from the PUD at the primary voltage level, where the PUD has provided special undertakings to the Customer, or in other circumstances where the PUD judges that a contract may be prudent. Unless otherwise specified in the Customer Contract, such contract will commence on its effective date and will, unless earlier terminated in accordance with the provisions of the Customer Contract, continue until such time as the Customer no longer receives service under this Schedule or the Customer Contract is terminated by mutual agreement of the PUD and the Customer.

(4) RATE: The monthly billing shall be the greater of: (i) the sum of the Base Charge, Demand Charge and Energy Charge; or, (ii) the Minimum Charge. Charges are calculated on a "per meter" basis. Each retail meter or billing installation shall be individually subject to the below charges. All rates are subject to adjustments pursuant to Rate Schedule 82.

Base Charge: cents per day per meter or billing installation

Effective Date	Base Rate
April 1, 2023	$1.35 / day
April 1, 2024	$2.10 / day
April 1, 2026	$4.85 / day

Demand Charge:

- First 100 kW per month of Billing Demand: $0 per kW - month
- Over 100 kW per month of Billing Demand:

Effective Date	Demand Rate (per kW)
January 1, 2024	$2.03

April 1, 2024	$2.67
January 1, 2025	$3.31
April 1, 2025	$3.86
January 1, 2026	$4.41
April 1, 2026	$4.97
January 1, 2027	$4.976
January 1, 2028	$5.531
January 1, 2029	$6.096
January 1, 2030	$6.6561
January 1, 2031	$7.2116

Energy Charge:

- First 30,000 kWh per month:

Effective Date	Energy Rate per kWh
November 1, 2023	$0.09000
April 1, 2025	$0.08365

- Over 30,000 kWh per month:

Effective Date	All Months per kWh
April 1, 2024	$0.08556
January 1, 2025	$0.08478
April 1, 2025	$0.08462
January 1, 2026	$0.08446
April 1, 2026	$0.08430
January 1, 2027	$0.08430
January 1, 2028	$0.08413
January 1, 2029	$0.08397
January 1, 2030	$0.08381
January 1, 2031	$0.08365

Minimum Charge: Sum of the Daily Charge and the Additional Charge for all connected load greater than 10 kW

Effective Date	Daily Charge	Additional Charge
April 1, 2023	$1.52 per day	$.01707 per kW > 10 per day
April 1, 2024	$2.27 per day	$.01707 per kW > 10 per day

(5) ADJUSTMENTS, LIMITATIONS OF LIABILITY, AND ADDITIONAL TERMS OF SERVICE: Service under this schedule is subject to the limitations on liability and other terms and conditions of service defined in the PUD's electric service regulations and Rate Schedule 82.

(6) TAX ADDITIONS: The above rates are subject to proportional increases to compensate for any gross revenue tax imposed by any municipal body or other governmental body having

jurisdiction upon the PUD.

(7) TRANSFER TO OTHER RATE SCHEDULES: A customer receiving service under this rate schedule whose electric service requirements change so as to no longer meet the criteria in Section (1) above shall be transferred to another Rate Schedule for which it qualifies as soon as is practical. Upon the expiration of the Term or earlier termination of any of the Customer Service Documents for any reason, the Customer shall, if it requires continued electric service, commence taking service under the then-applicable retail tariff prescribed by the PUD for firm service to customers in its class; provided, however, that any such service shall be subject to availability.

(8) BPA COST ADJUSTMENT: From time to time the Bonneville Power Administration ("BPA") adjusts its wholesale power and transmission rates to the PUD. At the discretion of the Commission, the rates in this Schedule may be adjusted to reflect BPA rate adjustments, either up or down, on the same date the BPA rate changes become effective. The adjusted rate will be developed by incorporating the BPA cost change into the Electric Cost of Service Model and rate design policies adopted by the Commission in the most recent rate proceeding.

Effective Date: April 1, 2026~~5~~

[Res. No. 6205 (2025); History: 6167 (2024); 6144 (2023); 6103 (2023); 6046 (2022); 6028 (as amended by 6032) (2021); 5980 (2020)]

SCHEDULE 23 – SPECIAL CONTINUOUS SERVICE

(1) AVAILABILITY: This schedule is available in all territory served by the PUD for non-metered service to television cable amplifiers, air traffic warning lights, and other such applications where metering is deemed impractical by the PUD.

This schedule requires that customer-owned, fixed load equipment be installed on existing PUD-owned distribution facilities.

(2) TYPE OF SERVICE: Sixty hertz alternating current. The PUD reserves the right of final determination of voltage and phase of service.

(3) RATE: The monthly billing shall be the sum of the Customer Charge and Energy Charge.

Customer Charge:
~~(effective April 1, 2024) 48¢ per day~~
(effective April 1, 2025) 65¢ per day
(effective April 1, 2026) 74¢ per day

Energy Charge:
(effective April 1, 2023) 8.88¢ per kWh
(effective November 1, 2023) 9.00¢ per kWh

Energy use shall be computed by the following formula:

$$\frac{\text{Equipment wattage rating x hours of operation}}{1000} = \text{kWh}$$

(4) ADJUSTMENTS, LIMITATIONS OF LIABILITY, AND ADDITIONAL TERMS OF SERVICE: Service under this schedule is subject to the limitations on liability and other terms and conditions of service defined in the PUD's electric service regulations and Rate Schedule 82.

(5) TAX ADDITIONS: The above rates are subject to proportional increases to compensate for any gross revenue tax imposed by any municipal body or other governmental body having jurisdiction upon the PUD.

(6) BPA COST ADJUSTMENT: From time to time the Bonneville Power Administration ("BPA") adjusts its wholesale power and transmission rate to the PUD. At the discretion of the Commission, the rates in this Schedule may be adjusted to reflect BPA rate adjustments, either up or down, on the same date the BPA rate changes become effective. The adjusted rate will be developed by incorporating the BPA cost change into the Electric Cost of Service Model and rate design policies adopted by the Commission in the most recent rate proceeding.

Effective Date: April 1, 2026~~5~~

[Res. No. 6205 (2025); History: 6167 (2024); 6144 (2023); 6103 (2023); 6046 (2022); 6028 (2021); 5806 (2017); 5735 (2015); 5708 (2015); 5639 (2013); 5626 (2013); 5574 (2012); 5553 (2011); 5470 (2009); 5450 (2009); 5440 (2009); 5418 (2009); 5043 (2002); 5011 (2001); 4963 (2000); 4848 (1999); 4835 (1999); 4600 (1997); 4010 (1993); 3908 (1993); 3405 (1990); 2879 (1985); 2726 (1983); 2704 (1983); 2684 (1983); 2644 (1982); 2509 (1981); 2445 (1980); 2442 (1980); 2345 (1979); 2202 (1978); 1996 (1975)]

SCHEDULE 24 – TIME OF USE GENERAL SERVICE

(1) AVAILABILITY: This schedule ("Schedule") is designed for non-residential customers who can significantly shift their loads throughout the day. Customers must have an average typical monthly load demand exceeding 500 kW. This Schedule is not available to "New Large Single Loads" as defined in Rate Schedule 37. Such loads shall be served under Rate Schedule 37 - New Large Single Loads.

(2) TYPE OF SERVICE: Sixty hertz alternating current. The PUD reserves the right of final determination of voltage and phase of service. Where mutually advantageous to the customer and the PUD, and at the option of the PUD, service may be metered on the primary side of the PUD's transformers.

(3) RATE: The monthly billing shall be the greater of: (i) the sum of the Base Charge, Demand Charge and Energy Charge; or, (ii) the Minimum Charge. Charges are calculated on a "per meter" basis. Each retail meter or billing installation shall be individually subject to the below charges. All rates are subject to adjustments pursuant to Rate Schedule 82.

Base Charge per day:

Effective Date	April 1, 2023	April 1, 2025
Base Charge per day	$1.35	$2.10

Energy Charge per kWh:

Effective Date	November 1, 2023	April 1, 2025
First 30,000 kWh	$0.0900	$0.08365
Over 30,000 kWh (July – March)	$0.0735	$0.08365
Over 30,000 kWh (April – June)	$0.0535	$0.08365

Demand Charge per kW of Billing Demand:

Effective Date	November 1, 2023	April 1, 2025
Billing Demand Up to 100 kW	N/A	N/A
Billing Demand Over 100 kW	$15.94	$10.48

Billing Demand shall be equal to the maximum 15-minute demand measured during the hours from 7 A.M. to 11 A.M local time, Monday through Saturday during the billing period.

Minimum Charge:

Effective Date	January 1, 2023	April 1, 2023
Daily charge	$1.17 per day	$1.52 per day
Additional daily charge for all connected load > 10 kW	$.01707 per kW/day	$.01707 per kW/day

(4) ADJUSTMENTS, LIMITATIONS OF LIABILITY, AND ADDITIONAL TERMS OF SERVICE: Service under this schedule is subject to the limitations on liability and other terms and conditions of service defined in the PUD's electric service regulations and Rate Schedule 82.

(5) TAX ADDITIONS: The above rates are subject to proportional increases to compensate for any gross revenue tax imposed by any municipal body or other governmental body having jurisdiction upon the PUD.

(6) TRANSFER TO AND FROM OTHER RATE SCHEDULES: If a customer qualifies and elects to be served under a different PUD rate schedule after having been served under this Rate Schedule 24, and elects to later be served again under this Rate Schedule 24, then: The customer must first pay a surcharge to the PUD equal to the monthly demand charge under the schedule or schedules the customer is transferring from for each month since the customer was last served under Rate Schedule 24.

(7) BPA COST ADJUSTMENT: From time to time the Bonneville Power Administration ("BPA") adjusts its wholesale power and transmission rate to the PUD. At the discretion of the Commission, the rates in this Schedule may be adjusted to reflect BPA rate adjustments, either up or down, on the same date the BPA rate changes become effective. The adjusted rate will be developed by incorporating the BPA cost change into the Electric Cost of Service Model and rate design policies adopted by the Commission in the most recent rate proceeding.

Effective Date: April 1, 2025

[Res. No. 6205 (2025); History: 6167 (2024); 6103 (2023); 6046 (2022); 6028 (2021); 5979 (2020); 5927 (2019); 5806 (2017); 5735 (2015); 5708 (2015); 5639 (2013); 5626 (2013); 5574 (2012); 5553 (2011); 5470 (2009); 5450 (2009); 5440 (2009); 5418 (2009); 5043 (2002); 5011 (2001); 4963 (2000); 4848 (1999); 4835 (1999); 4600 (1997); 4138 (1994); 4089 (1994)]

SCHEDULE 25 – GENERAL SERVICE, SMALL LOAD

(1) AVAILABILITY: This schedule ("Schedule") is available in all territory served by the PUD for commercial, industrial, governmental, institutional, agricultural, and multiple residential customers. This Schedule is not available to "New Large Single Loads" as defined in Rate Schedule 37. Such loads shall be served under Rate Schedule 37 - New Large Single Loads.

(2) TYPE OF SERVICE: Service is sixty Hertz alternating current delivered to one point of delivery. The PUD reserves the right of final determination of voltage and phase of service. Where mutually advantageous to the customer and the PUD, and at the option of the PUD, service may be metered on the primary side of the PUD's transformers.

(3) RATE: The monthly charges shall be the greater of: (i) the sum of the Base Charge and the Energy Charge; or, (ii) the Minimum Charge. Charges are calculated on a "per meter" basis. Each retail meter or billing installation shall be individually subject to the below charges. All rates are subject to adjustments pursuant to Rate Schedule 82.

Base Charge per day:

Effective Date	April 1, 2024	April 1, 2025
Base Charge per day	$0.92	$1.72

Energy Charge per kWh:

Effective Date	~~November 1, 2023~~	April 1, 2025	April 1, 2026
All kWh	~~$0.0900~~	$0.08365	$0.08572

Minimum Charge:

Effective Date	April 1, 2023	April 1, 2024
Daily charge	$0.75 per day	$1.10 per day
Additional daily charge for all connected load > 10 kW	$.01707 per kW/day	$.01707 per kW / day

(4) ADJUSTMENTS, LIMITATIONS OF LIABILITY, AND ADDITIONAL TERMS OF SERVICE. Service under this Schedule is subject to the limitations on liability and other terms and conditions of service defined in the PUD's electric service regulations and Rate Schedule 82.

(5) TAX ADDITIONS: The above rates are subject to proportional increases to compensate for any gross revenue tax imposed by any municipal body or other governmental body having jurisdiction upon the PUD.

(6) BPA COST ADJUSTMENT: From time to time the Bonneville Power Administration ("BPA") adjusts its wholesale power and transmission rate to the PUD. At the discretion of the

Commission, the rates in this Schedule may be adjusted to reflect BPA rate adjustments, either up or down, on the same date the BPA rate changes become effective. The adjusted rate will be developed by incorporating the BPA cost change into the Electric Cost of Service Model and rate design policies adopted by the Commission in the most recent rate proceeding.

Effective Date: April 1, 2026~~5~~

[Res. No. 6205 (2025); History: 6167 (2024); 6144 (2023); 6103 (2023); 6046 (2022); 6028 (2021); 5979 (2020); 5927 (2019); 5806 (2017); 5735 (2015); 5708 (2015); 5639 (2013); 5626 (2013); 5574 (2012); 5553 (2011); 5470 (2009); 5450 (2009); 5440 (2009); 5418 (2009); 5043 (2002); 5023 (2001)

SCHEDULE 36 – LARGE PRIMARY SERVICE

(1) APPLICABILITY; CONTRACT TERM: This schedule (this "Schedule") is available in all territory served by the PUD for unregulated service to loads with demands exceeding 5,000 kW, upon execution of a primary service contract between the PUD and the Customer (the "Customer Contract"). The term of each Customer Contract will commence on the effective date of such contract and will, unless earlier terminated in accordance with the provisions of this Schedule or under the terms of the Customer Contract, continue until such time as such Customer Contract is terminated by mutual agreement of the PUD and the Customer (such term, including any extensions and renewals thereof, the "Term").

Service under this Schedule is subject to the terms and conditions of this Schedule, Rate Schedule 82, the Customer Contract and the PUD's Electric Service Regulations (collectively, the "Customer Service Documents"). All capitalized terms used but not defined herein will have the respective meaning set forth in the Customer Contract or the other Customer Service Documents.

This Schedule does not apply to a "New Large Single Load" as defined in Rate Schedule 37. Such loads will be served by Rate Schedule 37 – New Large Single Loads.

(2) TYPE OF SERVICE: Three-phase, sixty-hertz alternating current at the primary voltage available.

(3) RATE:

- Demand Charge:
  ~~(effective April 1, 2024) $5.46 per kW of monthly billing demand~~
  (effective April 1, 2025) $5.94 per kW of monthly billing demand
  (effective April 1, 2026) $6.35 per kW of monthly billing demand
- Energy Charge:
  ~~(effective April 1, 2024) 6.35 cents per kWh~~
  (effective April 1, 2025) 6.63 cents per kWh
  (effective April 1, 2026) 6.862 cents per kWh

(4) MINIMUM CHARGE: The monthly minimum will be the minimum charge contracted for, but in no case less than $10,500.00.

(5) BILLING DEMAND: The monthly billing demand is subject to adjustment in accordance with Schedule 82, and will be:

(A) The maximum fifteen-minute demand established during the hours from 7 a.m. to 10 p.m. Pacific standard or daylight time as applicable, Monday through Saturday.

(B) All other hours – no demand charge.

(6) ADJUSTMENTS, LIMITATIONS OF LIABILITY, AND ADDITIONAL TERMS OF SERVICE: SERVICE UNDER THIS RATE SCHEDULE IS SUBJECT TO THE TERMS, CONDITIONS, LIMITATIONS OF LIABILITY, AND ADJUSTMENTS TO RATES AND BILLING DEMANDS SET FORTH IN RATE SCHEDULE 82 – ADJUSTMENTS, TERMS AND CONDITIONS OF SERVICE, AND LIMITATIONS OF LIABILITY.

(7) TRANSFER TO OTHER RATE SCHEDULES: A customer receiving service under this rate schedule whose electric power usage falls below the usage criteria in Section (1) above shall be transferred to another Rate Schedule for which it qualifies as soon as is practical. Upon the expiration of the Term or earlier termination of any of the Customer Service Documents for any reason, the Customer shall, if it requires continued electric service, commence taking service under the then-applicable retail tariff prescribed by the PUD for firm service to customers in its class; provided, however, that any such service shall be subject to availability.

(8) BPA COST ADJUSTMENT. From time to time the Bonneville Power Administration ("BPA") adjusts its wholesale power and transmission rates to the PUD. At the discretion of the Commission, the rates in this Schedule may be adjusted to reflect BPA rate adjustments, either up or down, on the same date the BPA rate changes become effective. The adjusted rate will be developed by incorporating the BPA cost change into the Electric Cost of Service Model and rate design policies adopted by the Commission in the most recent rate proceeding.

Effective Date: April 1, 2026~~5~~

[Res. No. 6205 (2025); History: 6167 (2024); 6144 (2023); 6103 (2023); 6046 (2022); 6028 (2021); 5806 (2017); 5735 (2015); 5708 (2015); 5639 (2013); 5626 (2013); 5574 (2012); 5553 (2011); 5470 (2009); 5450 (2009); 5440 (2009); 5418 (2009); 5043 (2002); 5011 (2001); 4963 (2000); 4848 (1999); 4835 (1999); 4600 (1997); 4010 (1993); 3908 (1993); 3405 (1990); 3386 (1990); 3211 (1988); 2879 (1985); 2726 (1983); 2704 (1983); 2684 (1983); 2644 (1982); 2509 (1981); 2445 (1980); 2442 (1980); 2345 (1979); 2202 (1978); 1996 (1975); 1653 (1970); 1392 (1966); 1371 (1966); 795 (1957)]

SCHEDULE 37 – NEW LARGE SINGLE LOADS

(1) AVAILABILITY: This schedule is available in all territory served by the PUD. All loads or portions of loads determined to be, or being monitored for determination as, a "New Large Single Load," as defined below, shall be served according to this rate schedule. Prior to receiving service under this Schedule, the Customer shall enter in to a contract with the PUD (the "Customer Contract").

A "New Large Single Load" is any load associated with a new facility, an existing facility, or an expansion of an existing facility:

(a) Which was not contracted for, or committed to, as determined by the Bonneville Power Administrator, by the PUD prior to September 1, 1979; and

(b) Which will result in an increase in power requirements of a customer of ten average megawatts or more in any consecutive twelve-month period.

(2) METERING: Any load or portion of a load determined to be, or being monitored for determination as, a "New Large Single Load" shall be separately metered. If facilities are not available for separately metering a load or a portion of a load which has been determined to be, or which is being monitored for determination as, a "New Large Single Load," such metering facilities shall be installed as soon as practicable.

(3) TYPE OF SERVICE: Three-phase, sixty-hertz alternating current at the primary voltage available.

(4) RATES AND BILLING: The PUD shall bill the customer for service over billing periods to be defined in the Customer Contract. The periodic rates for service provided under this Schedule 37 shall be specified in the Customer Contract, and shall include the following components (which components may be separated and rebundled in the manner as agreed between the PUD and the customer):

(a) Energy and Capacity. Rates to be based on the cost to the PUD of power available to serve the customer's load, or power to be acquired by the PUD to serve the customer's load, plus a reason able service fee, all in accordance with power supply arrangements agreed in writing between the customer and the PUD.

(b) Transportation and Losses. Rates to be established based on cost of service methodology applicable to all customer classes.

(c) Ancillary Services. Rates to cover load following, load shaping, firming, price stability, reactive power, risk premium, PUD overhead, reserves, and other services provided by the PUD.

(d) Customer Charges; Periodic Minimum Charges; Other Fixed Charges. A periodic fixed fee to cover non-variable or minimum costs. The PUD also reserves the right to collect contributions in aid of construction or other charges arising out of any required capital expansion or extraordinary costs.

(5) ADDITIONAL TERMS OF SERVICE: SERVICE UNDER THIS RATE SCHEDULE IS SUBJECT TO THE TERMS, CONDITIONS, AND LIMITATIONS OF LIABILITY, SET FORTH IN THE PUD'S ELECTRIC SERVICE REGULATIONS AND RATE SCHEDULE 82 - ADJUSTMENTS, TERMS AND CONDITIONS OF SERVICE, AND LIMITATIONS OF LIABLITY. THE ABOVE RATES AND BILLING DEMANDS ARE SUBJECT TO RATE SCHEDULE 82 - ADJUSTMENTS, TERMS AND CONDITIONS OF SERVICE, AND LIMITATIONS OF LIABILITY.

(6) TAX ADDITIONS: The above rates are subject to proportional increases to compensate for any gross revenue taxes imposed by any municipal body or other governmental entity having jurisdiction upon the PUD.

Effective Date: January 1, 2010

[Res. No. 5470 (2009); History: 5011 (2001); 4848 (1999); 4835 (1999); 4600 (1997); 4010 (1993); 3908 (1993); 3405 (1990); 2879 (1985); 2726 (1983); 2704 (1983); 2684 (1983); 2644 (1982); 1848 (1973); 1795 (1972); 1392 (1966); 1371 (1966)]

SCHEDULE 38 – LARGE 115 kV SERVICE

(1) AVAILABILITY: This schedule is available in all territory served by the PUD for physically unregulated service to loads with demands exceeding 5,000 kW, upon execution of a contract for a term of not less than 5 years.

This rate schedule does not apply to a "New Large Single Load" as defined in Rate Schedule 37. Such loads shall be served by Rate Schedule 37 - New Large Single Loads.

(2) TYPE OF SERVICE: Three-phase, sixty-hertz alternating current at 115 kilovolts.

(3) RATE: The monthly billing shall be the greater of: (i) the sum of the Demand Charge and Energy Charge; or, (ii) the Minimum Charge described in (4) below.

- Demand Charge:
  ~~(effective April 1, 2024) $4.96 per kW of monthly billing demand~~
  (effective April 1, 2025) $5.35 per kW of monthly billing demand
  (effective April 1, 2026) $5.72 per kW of monthly billing demand

- Energy Charge:
  ~~(effective April 1, 2024) 6.29 cents per kWh~~
  (effective April 1, 2025) 6.563 cents per kWh
  (effective April 1, 2026) 6.794 cents per kWh

(4) MINIMUM CHARGE: The monthly minimum shall be the minimum charge contracted for, but in no case less than $7,500.00.

(5) BILLING DEMAND: The monthly billing demand is subject to adjustment in accordance with Schedule 82, and shall be:

(a) The maximum fifteen-minute demand established during the hours from 7 a.m. to 10 p.m. standard or daylight time as applicable, Monday through Saturday.

(b) All other hours - no demand charge.

(6) ADJUSTMENTS, LIMITATIONS OF LIABILITY, AND ADDITIONAL TERMS OF SERVICE: SERVICE UNDER THIS RATE SCHEDULE IS SUBJECT TO THE TERMS, CONDITIONS, AND LIMITATIONS OF LIABILITY, SET FORTH IN THE PUD'S ELECTRIC SERVICE REGULATIONS AND RATE SCHEDULE 82 – ADJUSTMENTS, TERMS AND CONDITIONS OF SERVICE, AND LIMITATIONS OF LIABILITY. THE ABOVE RATES AND BILLING DEMANDS ARE SUBJECT TO RATE SCHEDULE 82 – ADJUSTMENTS, TERMS AND CONDITIONS OF SERVICE, AND LIMITATIONS OF LIABILITY.

(7) TAX ADDITIONS: The above rates are subject to proportional increases to compensate for any gross revenue tax imposed by any municipal body or other governmental body having jurisdiction upon the PUD.

(8) BPA COST ADJUSTMENT: From time to time the Bonneville Power Administration ("BPA") adjusts its wholesale power and transmission rate to the PUD. At the discretion of the Commission, the rates in this Schedule may be adjusted to reflect BPA rate adjustments, either up or down, on the same date the BPA rate changes become effective. The adjusted rate will be

developed by incorporating the BPA cost change into the Electric Cost of Service Model and rate design policies adopted by the Commission in the most recent rate proceeding.

Effective Date: April 1, 2026~~5~~

[Res. No. 6205 (2025); History: 6167 (2024); 6144 (2023); 6103 (2023); 6046 (2022); 6028 (2021); 5806 (2017); 5735 (2015); 5708 (2015); 5639 (2013); 5626 (2013); 5574 (2012); 5553 (2011); 5470 (2009); 5450 (2009); 5440 (2009); 5418 (2009); 5345 (2008)]

SCHEDULE 50 – MARKET-BASED SERVICE

(1) AVAILABILITY: This schedule is available in all territory which the PUD is authorized to serve, for service to customers determined to be eligible by the PUD.

(2) TYPE OF SERVICE; Service shall be set forth in the Customer Contract.

(3) RATES AND BILLING. The PUD shall bill the customer for service over billing period s to be defined in the Customer Contract. The periodic rates for service provided under this Schedule 50 shall be specified in the Customer Contract, and shall include the following components (which components may be separated and rebundled in the manner as agreed between the PUD and the customer):

(a) Energy and Capacity – Rates to be based on the cost to the PUD of power available to serve the customer's load, or power to be acquired by the PUD to serve the customer's load, plus a reason able service fee, all in accordance with power supply arrangements agreed in writing between the customer and the PUD.

(b) Transportation and Losses – Rates to be established based on cost of service method ology applicable to all customer classes.

(c) Ancillary Services – Rates to cover load following, load shaping, firming, p rice stability, reactive power, risk premium, PUD overhead, reserves, and other services provided by the PUD.

(d) Customer Charges; Periodic Minimum Charges; Other Fixed Charges – A periodic fixed fee to cover non -variable or minimum costs. The PUD also reserves the right to collect contributions in aid of construction or other charges arising out of any required capital expansion or extraordinary costs.

(4) TERMS OF SERVICE. Service under this schedule is subject to terms as set forth in the Customer Contract and the PUD's Electric Service Regulations. Said terms may include limitations or condition s on any rights of the customer to resume service from the PUD, upon the expiration or termination of the Customer Contract, under then -existing rate schedules.

(5) TAX ADDITIONS: The above rates are subject to proportional increases to compensate for any taxes imposed upon the PUD by any municipal body or other governmental entity having jurisdiction.

[Res. No. 4848 (1999); History: 4525 (1996)]

SCHEDULE 80 – RENEWABLE ENERGY CREDIT PROGRAM

(1) AVAILABILITY: This schedule is available in all territory served by the PUD for all customers.

(2) RENEWABLE ENERGY RESOURCES: This schedule provides customers with the voluntary option to purchase Qualified Alternative Energy Resources, as required by R.C.W. Chapter 19.29A. A Qualified Alternative Energy Resource includes any energy production facility powered by renewable technology such as wind, solar, biomass, geothermal, landfill gas, gas produced from wastewater treatment, wave action, low-impact hydro, or other renewable technologies meeting the definition of "Qualified Alternative Energy Resource" in R.C.W. § 19.29A.090(3).

Service under this schedule is provided through Renewable Energy Credits (RECs) obtained by the PUD either through its own supply of Renewable Energy Credits or through a clearinghouse or other system which secures the verifiable evidence that a third party has produced electricity from a Qualified Alternative Energy Resource and that such third party agrees to transfer credit from such production exclusively to the PUD.

The purchasing customer shall have the right to claim the associated Renewable Energy Credits to the extent allowed under applicable law. A purchasing customer may not resell or otherwise transfer the Renewable Energy Credits to any other party for any purpose.

(3) ENROLLMENT: Any customer may purchase RECs from the PUD in one of the ways described in the PUD's current customer service regulations. Charges for RECs will be included as a separate charge on the customer's bill and shall be reflected on the bill following the customer's request to purchase them.

The PUD will transfer a Customer's recurring RECs enrollment when a customer moves within the territory served by the PUD; however, a Customer may discontinue service under this schedule at any time.

(4) RATE: One REC consists of the environmental credits associated with 1000 kWh of electrical energy generated by Qualified Alternative Energy Resource. An unlimited number of RECs can be purchased at a cost of:

$4.50 per month per REC

The monthly charge will be the same every month and will continue until the customer cancels participation in the program, requests a change in the number of RECs requested, or leaves the PUD. If any of these circumstances should occur, charges will be prorated to reflect the amount of time the customer received service under this schedule.

Alternatively, any customer may make a one-time purchase of RECs. Under this option, a minimum of 5 RECs must be purchased and the one-time charge will occur on one bill.

(5) GENERAL PROVISIONS: Base rates and other terms of electric service shall be governed by the Rate Schedule under which the customer takes ordinary services. This Rate

Schedule does not provide electric service or electric power. Charges specified under this Rate Schedule are in addition to the charges specified in the Rate Schedule under which the customer takes its ordinary electricity service.

The Billing provisions of the PUD's Customer Service Regulations apply with the following modifications.

A. If the customer remits a partial payment, that payment shall first be applied to all other charges due the PUD with any residual payment amount applied to charges for RECs.

B. If a customer does not pay for their RECs charges, the PUD shall immediately discontinue selling RECs to that customer.

Effective Date: June 1, 2018

[Res. No. 5847 (2018); History: 5631 (2013); 5387 (2008); 5019 (2001)]

SCHEDULE 82 – ADJUSTMENTS, TERMS AND CONDITIONS OF SERVICE, AND LIMITATIONS OF LIABILITY

(1) APPLICABILITY: This schedule shall apply to other PUD rate schedules as described below.

(2) POWER FACTOR ADJUSTMENT: This adjustment shall apply, at the PUD's option, to all rate schedules with demand charge provisions. The measured demand shall be increased by one percentage point for each one hundredth (0.01) of a unit by which the average power factor is less than 0.97.

The formula for determining average power factor is as follows:

$$\text{Average Power Factor} = \frac{\text{kWh}}{\text{Divided By } \sqrt{(\text{kWh})^2 + (\text{Reactive Kilovolt Ampere Hours})^2}}$$

(Note: kWh = Kilowatt Hours)

The meter for measurement of Reactive Kilovolt Ampere hours will be ratcheted to prevent reverse registration. The billing demand shall be the measured demand as adjusted by this power factor adjustment.

(3) PRIMARY OWNERSHIP DISCOUNT: Customers on Rate Schedule 20 - General Service – Medium Load, Rate Schedule 24 – Time of Use General Service, and Rate Schedule 25 – General Service – Small Load who receive service at the PUD's primary voltage level, own or lease, and maintain the distribution system (transformers may be leased) beyond the PUD's point of delivery, and enter into an agreement with the PUD, may receive a five percent primary ownership discount on their total bill.

(4) REDUNDANT DISTRIBUTION CAPACITY: Customers who receive service under Rate Schedule 20 – General Service – Medium Load, Rate Schedule 24 – Time of Use General Service, and Rate Schedule 25 – General Service – Small Load and who enter into an agreement with the PUD may obtain redundant distribution capacity to serve their connected load. Redundant distribution capacity is a delivery service that provides capacity from an alternate path for delivery of electrical power. Redundant distribution capacity does not provide standby electrical power to backup customer-owned generation or other electrical power not provided by the PUD. It also does not guarantee uninterrupted electrical service. The PUD may provide such redundant distribution capacity if in the PUD's sole judgment such capacity can be reserved for the requesting customer without adversely impacting other customers, system operations, system reliability and safety.

The following monthly rates apply:

- Redundant Distribution Capacity Delivered at Secondary Voltage
  $1.23 per kW Connected Load per month.
- Redundant Distribution Capacity Delivered at Primary Voltage
  $1.18 per kW Connected Load per month.

In addition, a customer requesting this service may also be subject to charges under the PUD's Line Extension Policy and be required to reimburse the PUD for other costs incurred in establishing the requested redundant distribution capacity.

(5) HAT ISLAND SUBMARINE CABLE CHARGE: Hat Island is an island currently served by the PUD through a 3-mile long submarine cable. In order to partially fund a reserve account for submarine cable replacement, Hat Island customers will be charged:

- A flat fee of $0.79 per day

Beginning January 1, 2014, and on that date's anniversaries, by administrative action the Hat Island cable replacement charge will be escalated by 3% to account for expected inflation in submarine cable construction costs. The charge will be reviewed periodically to account for changes in the number of electric customers served on Hat Island. This charge is in addition to all other charges on each Hat Island customer's current rate schedule. Minimum bill customers will pay the minimum bill plus the cable charge. The charge cannot be reduced by customer discounts, BPA Residential Exchange Credits or net metering credits.

(6) TERMS AND CONDITIONS OF SERVICE; LIMITATIONS OF LIABILITY

(A) PAYMENTS

(i) Invoices – Promptly after the end of each calendar month during the Term, or, at the PUD's option, at the end of every other calendar month, the PUD will submit to the Customer an invoice for the amount due, at the applicable Rates, including applicable taxes and Penalty Amounts, from the Customer to the PUD for the Electric Power delivered to the Customer during such month, or the most recent period for which meter data is available, as computed from meter readings recorded by the PUD. Each such invoice will set forth the amount of Electric Power delivered in the applicable month, the Rate or Rates applicable thereto, and the amount due. The invoice shall be delivered to the address set forth in Notices provision of the Customer Contract, if any, or to the address specified in the Customer's account with the PUD.

(ii) Payment of Invoice Amounts – The amounts due under any invoice of the PUD will be paid by the Customer, in accordance with the provisions of the Customer Service Documents, within 25 days after the date of receipt of such invoice. Any such amounts remaining unpaid after the expiration of such period will bear interest, from the 26th day after receipt of the applicable invoice until paid in full to the PUD, at a rate equal to the lesser of (i) 125 percent of the then-current prime rate of at least 75 percent of the 30 largest banks in the United States, as published in The Wall Street Journal, or (ii) the highest rate allowed by law. The Customer will not be entitled, for any reason whatsoever, to withhold payment of all or any portion of the amount due under any invoice of the PUD. In the event that the Customer disputes all or any portion of any invoice of the PUD, the Customer will nonetheless pay the entire amount due under such invoice on or before the applicable payment due date, and any amount which may subsequently be determined (whether by agreement or otherwise) not to have been properly due from the Customer will promptly thereafter be refunded by the PUD to the Customer, with interest thereon at the rate provided above from the date on which such amount was paid by the Customer until the date of such refund.

(iii) PUD Account – Payment by the Customer of the amount due under any invoice of the PUD will be made by electronic funds transfer, Customer check, or other means acceptable to the PUD, sent by first-class mail to such account as is designated by the PUD in accordance with the notice provisions of the Customer Contract, if any, or sent by first-class mail or delivered by hand to the address specified in the PUD's invoice. The PUD may change such account from time to time and at any time by appropriate notice to the Customer.

(iv) Special Undertakings by the PUD – In the event that, for the purpose of providing requested service to the Customer, the PUD, with the prior approval of the Customer, enters into any separate or special obligation or undertaking on behalf of the Customer, including any special conditions of service set forth in the Customer Contract, the PUD and the Customer will agree on the amount of any separate rates, charges or contributions which may be payable by the Customer for or in connection therewith prior to initiation of service by the PUD.

(B) FACILITIES AND EQUIPMENT

(i) Ownership and Control of Facilities – The PUD will install, own, maintain and control all equipment and facilities for the distribution and delivery of Electric Power to the Customer, including but not limited to the metering equipment and facilities, that is located on the PUD side of the Point of Delivery (the "PUD's Facilities"), and the Customer will install, maintain and control all electrical equipment and facilities owned or controlled by the Customer on the Customer side of the Point of Delivery ("Customer's Facilities").

(ii) Maintenance of the Customer's Facilities – The Customer shall maintain the Customer's Facilities in proper and safe working order, and in compliance with any and all applicable national, state and local electrical codes and standards. The PUD will, upon reasonable advance notice to the Customer, and subject to the Customer's safety and security rules and regulations, be entitled to inspect all or any portion of the Customer's Facilities at any time and from time to time during the Term; provided, however, that, without in any way limiting the foregoing, the Customer acknowledges and agrees that the PUD will not at any time have any obligation to inspect the Customer's Facilities (or any portion thereof). Any inspection by the PUD will be for the limited purpose of determining that the Customer's Facilities are compatible with the PUD's Facilities and will not be made to determine whether the Customer's Facilities are installed and/or being operated as required by law, specifically including any electrical, safety or building code. Inspection by the PUD will not establish or imply any duty on the part of the PUD to discover or report any code violations or the existence of hazards of any nature.

(iii) Customer Impairment of PUD Service – The Customer agrees to operate the Customer's Facilities in such a manner as not to impair the electric service rendered by the PUD to any other customers of the PUD. In the event that the PUD reasonably determines that the Customer's use of its electric equipment and facilities in any manner impairs the PUD's electric service to any other customers of the PUD, the Customer will promptly after notice thereof from the PUD take such measures as are necessary to remedy such impairment, including but not limited to the installation of proper corrective apparatus.

(iv) PUD Disconnect Rights – In the event that, in the judgment of the PUD, any violation by the Customer of Sections (5)(B)(ii-iii) of this Schedule 82 or any other provision of the Customer Service Documents creates an emergency condition that threatens any person or property, including but not limited to the integrity of the PUD's electrical distribution system or any of the PUD's Facilities, or impairs the PUD's electric service to any other customers of the PUD, the PUD may, at its sole option, without any liability whatsoever to the Customer or any other person and without waiving any other right which it may have under the Customer Contract or applicable law, disconnect electrical service to the Customer's Premises until such condition has been remedied to the satisfaction of the PUD.

(v) No Dedication of Facilities – No undertaking by the Customer or the PUD under or pursuant to any provision of the Customer Service Documents will constitute or be deemed to constitute a dedication of all or any portion of the electrical system of either the PUD or the Customer to the other or to the public.

(C) PUD ACCESS AND EASEMENT RIGHTS: The Customer shall grant to the PUD any and all easements, entry and access rights and rights of way, including but not limited to any and all utility easements, which the PUD may deem necessary or appropriate for the transmission and delivery of electricity to the Point of Delivery, and for the purposes of installation, repair, inspection, maintenance, removal or improvement of the PUD's Facilities for service to Customer's Premises. The Customer agrees to provide suitable space and facilities at the Customer's Premises for the installation of the PUD's electricity meters and associated equipment, and hereby grants to the PUD all rights of access to and entry upon the Customer's property which the PUD may deem necessary or appropriate for purposes of reading, inspection, maintenance, repair or removal of such meters and associated equipment. Upon the expiration or termination of the service for any reason, the PUD will be entitled to remove any and all of the PUD's Facilities from the Customer's Premises. The Customer agrees to prepare, execute, acknowledge and record any and all instruments and agreements, including grants of easements, which the PUD may deem necessary or appropriate to confirm and better assure provisions of this section.

(D) FORCE MAJEURE

(i) Suspension of Obligations – Neither Party will be liable to the other for, or be considered to be in breach of or in default under the Customer Service Documents because of, any failure or delay in performance by such Party under the Customer Service Documents to the extent such failure or delay is caused by or results from any cause or condition which is beyond such Party's reasonable control, or which such Party is unable to prevent or overcome by exercise of reasonable diligence (any such cause or condition, a "Force Majeure"), including but not limited to: failure or threat of failure of facilities or equipment; fire, lightning, flood, earthquake, volcanic activity, wind, drought, storm and other natural disasters or acts of the elements; court order and act, or failure to act, of civil, military or governmental authority; strike, lockout and other labor dispute; epidemic, riot, insurrection, sabotage, cyber-attack, war and other civil disturbance or disobedience; labor or material shortage; failure of supply to the PUD of Electric Power which the PUD intended to use in its service to

the Customer; and electric disturbance originating in, transmitted through, or otherwise affecting the PUD's electric facilities or any electric facilities with which the PUD's facilities are interconnected.

(ii) Notice; Required Efforts to Resume Performance – Except where the PUD is responding to an outage caused by a storm, accident, or electrical disturbance or disruption, any Party claiming Force Majeure will give the other Party maximum practicable advance notice of any failure or delay resulting from a Force Majeure, and will use its reasonable best efforts to overcome the Force Majeure and to resume performance as soon as possible; provided, however, that nothing in the Customer Service Documents will be construed to require either Party to settle any strike or labor dispute in which it may be involved.

(iii) No Excuse of Payment Obligations – Notwithstanding any other provision of the Customer Service Documents, in no event will a Force Majeure excuse a Party's failure or delay to pay any amounts due and owing to the other Party under or pursuant to the Customer Service Documents.

(E) SERVICE INTERRUPTIONS AND SUSPENSIONS

(i) Customer Responsible for Protective Equipment – The PUD will use reasonable diligence to provide uninterrupted service to the Customer. However, the Customer will be responsible for installing any and all electrical protection equipment, such as back- up generators, surge protection devices, fusing, circuit breakers, relay protection controls and single phase protection (including but not limited to suitable protective apparatus on all motor installations to protect against single phasing of three-phase motors), that may be necessary or appropriate to prevent damage from reasonably foreseeable potential electrical disturbances such as reduced voltage, loss of service, over voltage, loss of phase wire and short circuit faults.

(ii) Notwithstanding any other provision of the Customer Service Documents, neither the PUD nor any electric utility or federal power marketing agency with which the PUD is interconnected will be in breach of or default under the Customer Service Documents, or have any responsibility or liability whatsoever to the Customer or any other person under the Customer Service Documents or otherwise, for or in connection with any service interruption, suspension, curtailment or fluctuation or disturbance of electric energy originating outside and passing through the electrical system of the PUD, whatever the cause, or any service interruption, suspension, curtailment or fluctuation or disturbance of electric energy originating inside the electrical system of the PUD caused by or resulting from any cause other than the gross negligence or willful misconduct of the PUD. The Customer hereby waives, and releases the PUD and its Commissioners, officers, employees and agents and each of the heirs, personal representatives, successors and assigns of any of the foregoing from, any and all liabilities, losses, claims, damages, costs, expenses, demands, fines, judgments and penalties in any manner caused by, resulting from or arising out of or in connection with any service interruption, suspension, curtailment or fluctuation or disturbance of electrical energy originating in, or passing through, or in parallel with, or intended for delivery to, the electrical system of the PUD, except to the extent (and only to the extent) that such interruption, suspension, curtailment, fluctuation or disturbance

originated inside the electrical system of the PUD and was caused by the gross negligence or willful misconduct of the PUD. Notwithstanding any other provision of the Customer Service Documents, in no event will the liability of the PUD or its Commissioners, officers, employees and agents or any of the heirs, personal representatives, successors and assigns of any of the foregoing for any interruption, suspension, curtailment, fluctuation or disturbance originating inside the electrical system of the PUD and caused by the gross negligence or willful misconduct of the PUD exceed, in the aggregate, the aggregate amount paid by the Customer to the PUD for and with respect to Electric Power purchased from the PUD under the Customer Contract during the six months immediately preceding such interruption, suspension, curtailment, fluctuation or disturbance. Without in any way limiting the foregoing, in the event that any service interruption, suspension, curtailment or fluctuation or disturbance of electric energy extends for a period in excess of 24 continuous hours, the PUD will reduce the Minimum Charge for such month on a pro rata basis in proportion to the length of such service interruption, suspension, curtailment or fluctuation or disturbance of electric energy.

(iii) Emergency Interruptions – The PUD will have the right, at any time during the Term, without any liability whatsoever to the Customer or any other person, to interrupt, suspend or curtail service to the Customer in the event that the PUD determines that a failure to do so may endanger any person or property, or is otherwise contrary to prudent utility practice as such term is used in the electric utility industry at the time of such interruption, suspension or curtailment. The PUD will give the Customer the maximum practicable advance notice of any such action and will resume service to the Customer as soon as possible after the condition giving rise to the endangerment to person or property or the violation of prudent utility practice, as applicable, is resolved.

(F) INDEMNIFICATION

(i) Indemnification by Customer – Except as otherwise provided in the Customer Service Documents, the Customer hereby indemnifies and agrees to hold harmless and release the PUD and each and all of its Commissioners, officers, employees and agents and each of the heirs, personal representatives, successors and assigns of any of the foregoing from and against any and all liabilities, losses, claims, damages, costs, demands, fines, judgments and penalties, together with reasonable attorneys' fees and out-of-pocket expenses incurred in connection with any of the foregoing ("Covered Liabilities") caused by, resulting from, or arising out of or in connection with (i) any of the Customer's Facilities or any other facilities or equipment of the Customer, (ii) any negligence or intentional misconduct of the Customer or any of its officers, employees, agents, contractors or subcontractors, or (iii) any failure of the Customer duly to perform or observe any term, provision, covenant, agreement or condition hereunder to be performed or observed by or on behalf of the Customer. In any and all claims against the PUD by any employee of the Customer, the indemnification and hold harmless obligation herein will not be limited in any way by any limitation on the amount or type of damages, compensation, or benefits payable by or for the Customer under workers compensation acts, disability benefit acts, or other employee benefit acts; and the Customer hereby specifically and expressly waives the immunity of the

Customer under such acts; provided, however, that the Customer's waiver of immunity by the provisions of this section extends only to claims against the PUD by or on behalf of an employee of the Customer, and does not include, or extend to, any claims by the Customer's employees directly against the Customer.

(ii) Indemnification by PUD. Except as otherwise provided in the Customer Service Documents, the PUD hereby indemnifies and agrees to hold harmless and release the Customer and its directors, officers, employees and agents and each of the heirs, personal representatives, successors and assigns of any of the foregoing from and against any and all Covered Liabilities caused by, resulting from, or arising out of or in connection with (i) any of the PUD's Facilities, (ii) any negligence or intentional misconduct of the PUD or any of its officers, employees, agents, contractors or subcontractors, or (iii) any failure of the PUD duly to perform or observe any term, provision, covenant, agreement or condition hereunder to be performed or observed by or on behalf of the PUD. In any and all claims against the Customer by any employee of the PUD, the indemnification and hold harmless obligation herein will not be limited in any way by any limitation on the amount or type of damages, compensation, or benefits payable by or for the PUD under workers compensation acts, disability benefit acts, or other employee benefit acts; and the PUD hereby specifically and expressly waives the immunity of the PUD under such acts; provided, however, that the PUD's waiver of immunity by the provisions of this section extends only to claims against the Customer by or on behalf of employees of the PUD, and does not include, or extend to, any claims by the PUD's employees directly against the PUD.

(G) LIMITATION ON LIABILITY

Notwithstanding any other provision of the Customer Service Documents, neither the Customer nor the PUD will be liable under or pursuant to the Customer Service Documents for indirect, incidental, special, exemplary, punitive or consequential damages, including but not limited to damages for lost profits, revenues or benefits, loss of use of property, cost of capital, cost of purchased or replacement power or (except only as and to the extent otherwise expressly provided in a Customer Contract) claims for service interruption, even if such Party has been advised of the possibility or existence of such damages.

(H) DEFAULT AND TERMINATION

(i) Default by the Customer – If any of the following events will occur:

(a) Material breach or material default by the Customer in the performance of any term, condition, covenant or agreement of the Customer Service Documents to be performed by the Customer, which breach or default: (i) if reasonably capable of being cured within 30 days, is not cured within 30 days after notice to the Customer from the PUD; or (ii) if not so capable of being cured within such 30-day period, the Customer does not commence to cure within such 30-day period or does not diligently proceed thereafter to cure with reasonable promptness; or

(b) A repeated failure or refusal by the Customer to perform, substantially in

accordance with the Customer Service Documents, any or all of its obligations under the Customer Service Documents, thereby committing a material breach which substantially impairs the value of the Customer Contract to the PUD, which failure or refusal recurs after notice to the Customer from the PUD that such material breach will, if repeated, constitute a default entitling the PUD to terminate the Customer Contract; or

(c) The institution against the Customer of any proceeding seeking to adjudicate the Customer as a bankrupt or insolvent, or the making by the Customer of a general assignment for the benefit of its creditors, or the appointment of a receiver on account of the insolvency of the Customer, or the filing by or against the Customer of a petition seeking to take advantage of any other law relating to bankruptcy, insolvency, reorganization, winding up, composition, or readjustment of debts and, in the case of any such proceeding instituted against (but not by) the Customer, such proceeding is not dismissed within 60 days after such filing and notice to the Customer from the PUD;

then, in such event, the PUD will be entitled, at its sole option, and without prejudice to any other rights or remedies available to the PUD under the Customer Service Documents or applicable law, to terminate the Customer Service Documents and each and all of its obligations thereunder, effective immediately upon notice to the Customer, without liability to the PUD or any other person, except as otherwise expressly provided in this section.

(ii) Default by the PUD – If any of the following events will occur:

(a) Material breach or material default by the PUD in the performance of any term, condition, covenant or agreement of the Customer Service Documents to be performed by the PUD, which breach or default: (i) if reasonably capable of being cured within 30 days, is not cured within 30 days after notice to the PUD from the Customer; or (ii) if not so capable of being cured within such 30-day period, the PUD does not commence to cure within such 30-day period or does not diligently proceed thereafter to cure with reasonable promptness; or

(b) A repeated failure or refusal by the PUD to perform, substantially in accordance with the Customer Service Documents, any or all of its obligations under the Customer Service Documents, thereby committing a material breach which substantially impairs the value of the Customer Contract to the Customer, which failure or refusal recurs after notice to the PUD from the Customer that such material breach will, if repeated, constitute a default entitling the Customer to terminate the Customer Contract;

then, in such event, the Customer will be entitled, at its sole option, and without prejudice to any other rights or remedies available to the Customer under the Customer Service Documents or applicable law, to terminate the Customer Service Documents (as they apply to Customer) and each and all of its obligations thereunder, effective immediately upon notice to the PUD, without liability to the Customer or any other person, except as otherwise expressly provided in this section.

(iii) Provisions Exclusive for Termination for Breach – This Section (5)(H) provides the exclusive means to terminate the Customer Service Documents for breach absent agreement between the Parties; provided, however, that without in any way limiting the foregoing, nothing in this section will preclude or limit any other remedy which a Party may have at law or in equity for breach by the other Party.

(7) TAXES

(A) Taxes – In addition to the Rates payable by the Customer hereunder for Electric Power, the Customer will pay all taxes, which are applicable for or with respect to such purchase of Electric Power, at the applicable rates.

(B) Tax Increases or Surcharges – In the event that federal or state regulatory changes during the Term result in an increase in any taxes or surcharges payable by the PUD for or with respect to sales of Electric Power or other services provided under or in connection with the Customer Contract, the PUD will, in accordance with any and all requirements of applicable law and of the applicable policies and procedures of the PUD, and effective upon notice to the Customer, be entitled to increase the Rates payable by the Customer hereunder by an amount which the PUD determines on a fair and nondiscriminatory basis to be the amount of such increased taxes or surcharges attributable to such sales or services under or in connection with the Customer Contract.

(8) EFFICIENT USE OF ENERGY: The Customer will consider installing cost-effective energy efficiency measures and will consider buying cost-effective energy efficient equipment when purchasing new equipment or replacing existing equipment. The PUD will offer suggestions for efficient energy use and inform the Customer of financial and technical assistance available through PUD programs for energy conservation and efficiency purposes.

(9) DEFINITIONS: For purposes of any applicable Rate Schedule and any Customer Contract, the terms set out below are defined as follows:

1.1 Commission means the PUD's elected Board of Commissioners.

1.2 Customer Service Documents means the documents defining the terms and conditions of the PUD's provision of Electric Power to the Customer, comprising the Schedules, the Regulations, the Customer Contract, if any, and any other contract agreed to between the PUD and the Customer setting forth the terms and conditions of any special condition of service or undertaking (such as redundant delivery points) related to provision of Electric Power by the PUD to the Customer, provided that, contracts related to the provision of energy conservation services, demand response services, customer-owned generation, and leasing of transformers and other electrical equipment shall not be included in the definition of Customer Service Documents.

1.3 Electric Power means electric energy and capacity.

1.4. Point of Delivery means: (a) the Point of Delivery identified in the Customer Contract, if any; (b) if no Customer Contract is in place, the Point of Delivery as defined in the Customer Service Regulations; and, (c) if no Customer Contract is in place and the Customer belongs to a class for which no definition appears in the Customer Service Regulations, the Point of Delivery shall be the Customer side of the PUD's meter used to

serve the Customer (it being understood that the PUD owns the meter and associated equipment).

1.5 Rates, if not otherwise defined in the Customer Contract, mean at any given time, the then-current rates and charges, as set forth in the Rate Schedule applicable to power purchasers in the Customer's class, as they may be amended from time to time and at any time by the PUD's Board of Commissioners (the "Commission"), payable by the Customer for Electric Power and related services under this Contract.

1.6. Regulations means the PUD's Customer Service Regulations for Electric Service, or any successor thereto.

1.7. Schedules, if not otherwise defined in the Customer Contract, means the PUD's Rate Schedule applicable to the Customer plus this Rate Schedule 82, collectively.
1.8 Term, unless otherwise specified with respect to a particular obligation undertaken by the PUD in a Customer Contract, means the period during which the Customer takes Electric Power from the PUD, provided that any obligation arising prior to termination of service shall remain in force until satisfied.

All capitalized terms used but not defined herein will have the respective meanings set forth in this Rate Schedule 82 or other applicable Rate Schedule, in the Regulations, or in the Customer Contract, if any. Unless otherwise expressly stated, the terms of the Rate Schedules shall prevail over any conflicting terms in a Customer Contract or the Regulations, and the terms of a Customer Contract shall prevail over any conflicting terms in the Regulations.

(10) INDEPENDENT CONTRACTORS: The Parties to the Customer Service Documents are independent contractors and will not be deemed to be partners, joint venturers, franchisors, franchisees, or agents of each other for any purpose whatsoever under or in connection with the Customer Contract.

(11) ASSIGNMENT; BINDING AGREEMENT:

(i) Assignment Prohibited Without Consent. Neither the PUD nor the Customer will, without the prior written consent of the other Party, which consent will not be unreasonably withheld, assign, pledge or transfer all or any part of, or any right or obligation under, the Customer Service Documents, whether voluntarily or by operation of law. Any attempted assignment, pledge or transfer of all or any part of, or any right or obligation under, the Customer Service Documents in violation of the foregoing requirements will be null and void.

(ii) Contract Binding on Successors and Assigns. The Customer Service Documents are binding on and will inure to the benefit of the PUD and the Customer and their respective successors and assigns and legal representatives.

(12) NO THIRD-PARTY BENEFICIARIES: Except as expressly set forth in this Rate Schedule 82, none of the provisions of the Customer Service Documents will inure to the benefit of or be enforceable by any third party.

(13) ENTIRE AGREEMENT: The Customer Service Documents sets forth the entire agreement of the Parties and supersede any and all prior agreements with respect to the subject

matter of the Customer Service Documents. The rights and obligations of the Parties thereunder will be subject to and governed by the Customer Service Documents. The headings used herein are for convenience of reference only and will not affect the meaning or interpretation of the Customer Service Documents.

(14) WAIVERS: Except as otherwise provided herein or as agreed by the PUD and the Customer, no provision of the Customer Service Documents may be waived except as documented or confirmed in writing. No waiver at any time by a Party of any right with respect to a default under the Customer Service Documents, or with respect to any other matter arising in connection therewith, will be deemed a waiver with respect to any subsequent default or matter. Either Party may waive any notice or agree to accept a shorter notice than specified in the Customer Service Documents. Such waiver of notice or acceptance of shorter notice by a Party at any time regarding a notice will not be considered a waiver with respect to any subsequent notice required under the Customer Service Documents.

(15) INVALID PROVISION: The invalidity or unenforceability of any provision of the Customer Service Documents will not affect the other provisions of the Customer Service Documents, and the Customer Service Documents will be construed in all respects as if such invalid or unenforceable provisions were omitted.

(16) FURTHER ASSURANCES: Each Party hereto covenants and agrees to do all things necessary or advisable, including but not limited to the preparation, execution, delivery and recording of any instruments or agreements, in order to confirm and better assure the intent and purposes of the Customer Service Documents.

(17) GOVERNING LAW; VENUE: The Customer Service Documents shall be governed by and construed in accordance with the laws of the State of Washington (regardless of the laws that might otherwise govern under applicable principles of conflicts of law of such state). Any lawsuit or judicial action or proceeding arising out of or relating to the Customer Service Documents must be heard in the Superior Court of the State of Washington in and for Snohomish County or the United States District Court for the Western District of Washington, Seattle, subject to all applicable requirements of notice and exhaustion of remedies at the PUD.

(18) RULES OF CONSTRUCTION: Whenever in the Customer Service Documents the context so suggests, references to the masculine shall be deemed to include the feminine, references to the singular shall be deemed to include the plural, and references to "or" shall be deemed to be disjunctive but not necessarily exclusive. No provision of the Customer Service Documents shall be construed in favor of or against either any Party by reason of the extent to which any such Party or its counsel participated in the drafting thereof or by reason of the extent to which such provision or any other provision or provisions of the Customer Service Documents is or are inconsistent with any prior draft thereof.

Effective Date: January 1, 2023

[Res. No. 5613 (2023); History: 5613 (2022); 5613 (2021), 5613 (2020), 5613 (2019); 5613 (2018); 5613 (2017); 5613 (2016); 5709 (2015); 5613 (2015); 5613 (2014); 5613 (2013); 5613 (2012); 5574 (2012); 5470 (2009); 5418 (2009); 5200 (2005); 5023 (2001); 5011 (2001); 4848 (1999); 4835 (1999); 3908 (1993); 3405 (1990); 3386 (1990); 2879 (1985); 2726 (1983); 2345 (1979); 2202 (1978); 1996 (1975); 1371 (1966)]

SCHEDULE 83 – PUD RETAIL ELECTRIC VEHICLE CHARGING

(1) AVAILABILITY: This schedule ("Schedule") is available in all territory served by the PUD for publicly available electric vehicle charging equipment that is operated by the PUD.

(2) RATE:

a. For chargers utilizing direct-current (DC) electricity, also known as Level 3 chargers:

Energy charge: 46 cents per kWh

b. For chargers utilizing 240-Volt alternating-current (AC) electricity, also known as Level 2 chargers:

Energy charge: 22 cents per kWh

(3) ADJUSTMENTS, LIMITATIONS OF LIABILITY, AND ADDITIONAL TERMS OF SERVICE: Service under this Schedule is subject to the limitations on liability and other terms and conditions of service defined in the PUD's electric service regulations and Rate Schedule 82.

(4) TAX ADDITIONS: The above rates are subject to proportional increases to compensate for any gross revenue tax imposed by any municipal body or other governmental body having jurisdiction upon the PUD.

(5) BPA COST ADJUSTMENT: From time to time, the Bonneville Power Administration ("BPA") adjusts its wholesale power and transmission rates to the PUD. At the discretion of the Commission, the rates in this Schedule may be adjusted to reflect BPA rate adjustments, either up or down, on the same date the BPA rate changes become effective. The adjusted rate will be developed by incorporating the BPA cost change into the Electric Cost of Service Model and rate design policies adopted by the Commission in the most recent rate proceeding.

Effective Date: August 1, 2024

[Res. No. 6182 (2024); History: 6144 (2023); 6056 (2022); 6012 (2021)]

SCHEDULE 90 – FACILITIES SMALLER THAN 100 kW

(1) AVAILABILITY: This schedule is available in all territory served by the PUD to any customer accepted by the PUD as a cogenerator or small power producer who executes a contract with the PUD regarding such status. The schedule shall apply to power generated by cogeneration or small power production facilities with a nameplate capacity of 100 kW or less.

(2) RATE: The PUD shall purchase power from an eligible facility at a rate equal to the energy component of the retail rate at which the PUD provides electrical service to the facility. Energy component means the annual average cost in cents per kWh of electricity excluding any Washington State revenue taxes.

Such rate may be modified by Commission resolution, subject to the criteria set forth in the PUD's Cogeneration and Small Power Production Service Policy, and FERC rules adopted pursuant to PURPA, Section 210.

(3) TERMS OF SERVICE: Service under this schedule shall be in accordance with the PUD's Cogeneration and Small Power Production Service Policy, as well as interconnection, safety, and reliability standards, and any other applicable PUD standards, policies or procedures.

Effective Date: April 1, 2009

[Res. No. 5260 (2006); History: 4848 (1999); 3908 (1993); 3405 (1990); 2473 (1981)]

SCHEDULE 200 – NET METERING PROGRAM

(1) APPLICABILITY: This rate schedule shall apply to other PUD rate schedules as described below.

(2) DEFINITIONS:

(A) "Cogeneration Facility" means a facility that provides or is capable of providing from a common fuel source both (i) thermal energy that is made available for processes and applications other than electrical generation and (ii) electric energy. To qualify under this Schedule 200, the Cogeneration Facility must meet the standards for "new qualifying facilities" established under 16 U.S.C. § 824a-3(n) and 18 C.F.R. § 292.205.

(B) "Net Metering System" means a fuel cell, a Cogeneration Facility, or a facility that produces electric energy using water, wind, solar energy or biogas as a fuel if the facility:

- has a generating capacity of not more than one hundred (100) kilowatts AC;
- is located on the customer-generator's premises;
- is connected to and operates in parallel with the PUD electric distribution system; and
- is intended primarily to offset part or all of the customer-generator's requirements for electricity.

(C) "Aggregated Meter" means a PUD meter serving the same customer, located on customer-generator's premises that the customer has requested be credited with the excess energy generated by the customer's Net Metering System. Aggregated Meter installed on or after July 1, 2019 must be located on the same or a contiguous parcel of property as the customer's Net Metering System.

(D) "Program Year" means the period from April 1 through March 31.

(E) "Premises" means any residential property, commercial real estate, or lands, owned or leased by a customer-generator within the service area of the PUD.

(F) "Net Metering Aggregation" means the administrative crediting of excess energy generated by a customer's Net Metering System to an Aggregated Meter, at the applicable rate of the Aggregated Meter.

(3) AVAILABILITY: The Net Metering Program is available to customers (i) who have a Net Metering System that can be interconnected to the PUD's electric system without exceeding the limitations on the number of customer-owned generators that may be interconnected to the relevant distribution feeder line, circuit, or network as may be established by the PUD to protect public safety and system reliability, (ii) who purchase electric power from the PUD under the provisions of another PUD rate schedule, and (iii) who sign a Net Metering Agreement with the PUD allowing them to interconnect to and operate in parallel with the PUD electric distribution system.

The Net Metering Program is available to new participants on a first-come, first-served basis until such time that the Board of Commissioners implements a standard rate schedule pursuant to RCW Chapter 80.60. Such standard rate schedule shall be effective no sooner than either: (a)

June 30, 2029; or (b) such time as the cumulative capacity of fuel cells and generators participating in the program exceeds 58.204 megawatts AC (4% of the PUD's peak demand in 1996), whichever occurs first. Not less than 29.102 megawatts (one-half of the PUD's 1996 peak demand available for net metering systems) shall be reserved for the cumulative generating capacity attributable to Net Metering Systems that use water, wind, solar energy or biogas as a fuel.

The PUD will not provide wheeling or transmission services for a customer-generator.

(4) BILLING ADJUSTMENT: PUD charges for electric energy are adjusted as follows.

The customer shall pay for the net energy used by the customer in accordance with the following formula: (a) the customer shall pay the applicable energy charge for all net electric energy used in any billing period in excess of the amount of electricity produced by the customer during that billing period; (b) the customer shall receive a credit for all electric energy produced during a billing period in excess of the amount of electric energy supplied by the PUD during that period, such credit to be applied to the customer's future electric bills, except that; (c) any energy balance remaining in favor of the customer under the provisions of subparagraph 5(F) on March 31 of any calendar year shall be zeroed out with no further liability to the PUD and no credit to the customer for that balance. For the purposes of the Net Metering Program, "billing period" shall be the billing period applied to customers of the same class and in the same geographic area as a customer participating in the Net Metering Program. The price for electric energy provided to or credited to a customer under the Net Metering Program shall be the price charged for such electric energy by the PUD under the provisions of the rate schedule under which the customer receives service, as such rate schedule may be revised from time to time by the PUD's Board of Commissioners. A customer participating in the Net Metering Program shall be billed on the schedule applicable to customers in the same class and geographic area as that customer and shall be subject to the payment terms specified in the PUD's Customer Service Regulations.

The Net Metering Program billing adjustment only reduces the number of kWh consumed for purposes of calculating the energy charge. A customer participating in the Net Metering Program is subject to all other charges, rates, terms and conditions, including any base charges, demand charges, and minimum charges, of the PUD rate schedule under which the customer receives service. The net metering of electricity shall not reduce the customer's bill to less than the sum of other charges.

(5) SPECIAL TERMS AND CONDITIONS FOR NET METERING AGGREGATION: In addition to all other provisions of this schedule, the following provisions apply when the customer-generator requests Net Metering Aggregation:

(A) An Aggregated Meter must be and remain on customer-generator's Premises.

(B) Beginning on July 1, 2019, new Aggregated Meters must be located on the same or a contiguous parcel of property as the customer's Net Metering System, and a customer-generator may only aggregate one meter. Net Metering customers that have participated in the Yearly Aggregation process prior to June 30, 2019 may continue to be aggregated on an annual basis.

(C) An Aggregated Meter must be and remain billed to the customer-generator.

(D) The Net Metering aggregation basic charge is applied annually to the meters requested by the customer generator to be aggregated. The Net Meter Aggregation basic charge is non-refundable.

(E) Net Meter Aggregation requests must be received by the PUD 30 days prior to conclusion of the Program Year and accompanied by payment of the Net Metering Aggregation basic charge. See PUD's Customer Service Regulations.

(F) Generated energy and excess generated energy shall be subtracted from the metered energy registered on the Net Meter first. For Monthly Aggregation, the credits will then be subtracted from the Aggregated Meter for the same billing period. At the conclusion of the program year, excess generated energy shall be subtracted from the eligible charges on the Yearly Aggregated Meter and excess generated energy which cannot be applied via Monthly or Yearly Aggregation shall be zeroed out with no further liability to the PUD and no credit to the customer for that balance.

(G) A meter requested to be aggregated shall not change its rate class or rate schedule as a result of Net Metering Aggregation.

Effective Date: December 3, 2019

[Res. No. 5931 (2019); History: 5583 (2012); 5261 (2006); 4920 (2000); 4848 (1999); 4819 (1998)]

SCHEDULE 201 – NET BILLING

(1) APPLICABILITY: This rate schedule shall apply to other District rate schedules as described below.

(2) DEFINITIONS:

(G) "Cogeneration Facility" means a facility that provides, or is capable of providing, from a common fuel source both (i) thermal energy that is made available for processes and applications other than electrical generation and (ii) electric energy. To qualify under this rate schedule, the Cogeneration Facility must meet the standards for "new qualifying facilities" established under 16 U.S.C. § 824a-3(n) and 18 C.F.R. § 292.205.

(H) "Small Distributed Generation" means a fuel cell, a Cogeneration Facility, or a facility that produces electric energy using water, wind, solar energy, biomass, biogas, or other generally-accepted renewable resource such that the facility:

- Is located on property or lands owned or leased by the customer-generator;
- Operates in synchronization with the District's electric distribution system;
- Is connected on the customer's side of the meter and is intended primarily to offset part or all of the customer-generator's requirements for electricity; and
- Has a nameplate capacity limit as shown in the table below. The nameplate capacity of adjacent, electrically-separate facilities using a like fuel type that are owned or operated by a common customer-generator, regardless of artificial segmentation, shall be measured in aggregate.

Period	AC Nameplate capacity
January 1, 2025 – September 30, 2025	Less than 200 kilowatts
After September 30, 2025	Less than 1000 kilowatts

(I) "Solar-only" means a facility with Small Distributed Generation that consists of only solar-energy generation and no other combinations of energy-generating technologies, battery storage, or hybrid system arrangements.

(3) AVAILABILITY: This rate schedule is available to customers (i) whose generation qualifies as a "Cogeneration Facility" or "Small Distributed Generation" as defined in Section 2 and can be interconnected to the District's electric system without exceeding the limitations of the relevant distribution feeder line, circuit, or network as may be established by the District to protect public safety and system reliability, (ii) who purchase electric power from the District under the provisions of another District rate schedule, (iii) who sign an agreement with the District allowing them to interconnect to and operate in synchronization with the District electric distribution system. The District may, at its sole discretion, pause access to this rate schedule as may be required by the constraints of the District's systems and staff.

(4) BILLING ADJUSTMENT: The customer shall pay for all electric energy that physically flows from the District to the customer in any billing period under the provisions of the rate schedule under which the customer receives service and shall be subject to the payment terms specified in the District's Customer Service Regulations. Any Minimum Charge described in the rate schedule under which the customer receives service shall apply to the consumptive portion of the bill. Generation credits shall be applied thereafter.

(5) RATE:

The customer shall receive monetary bill credits for all electric energy that physically flows to the District from the customer during the billing periods denoted in the ~~below~~ table below. Such credits shall be paid in cents per kWh at the following rates:

For Solar-only Generation:

Bill Year	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
2025	3.83	3.83	3.83	2.97	2.97	4.11	4.11	4.11	4.11	2.97	3.83	3.83
2026	3.83	3.83	3.83	4.605	4.605	3.956	3.956	3.956	3.956	4.605	4.381	4.381
2027	4.381	4.381	4.381									

For Other Eligible Generation:

Pricing may be calculated based on the specific attributes of the resource, net of customer consumption, upon request.

Effective Date: ~~January~~ April 1, 202~~5~~6

[Res. No. 6204 (2024)]

SCHEDULE 210 – DEMAND EXCHANGE

(1) AVAILABILITY: This schedule is available in all territory served by the PUD for commercial, industrial, governmental, institutional, agricultural, and other consumers with qualifying loads. This schedule does not apply to service locations with measurable, maximum hourly demand of less than (500 kW).

(2) PROGRAM DESCRIPTION: Participants in the PUD's Demand Exchange program are offered the opportunity to voluntarily curtail electric usage (minimum hourly curtailment: 500 kW) at their service location(s), at distinct times of day, in exchange for billing credits to their PUD power bill. Exchange offers will be made by the PUD, at times when power demand on the PUD system is such that load reductions would provide a tangible economic benefit to the PUD's consumers. Participation in the Demand Exchange program does not guarantee that the PUD will offer to purchase demand curtailments or that it will confirm and take delivery of purchases of demand curtailment if offered. Nor does participation in the Demand Exchange program guarantee that the PUD will pay any particular price for purchase of demand curtailments.

(3) BILLING CREDIT: The value of the power bill credit will be determined based upon the hourly exchange price offered by the PUD, the amount of load, measured in kW, for which the PUD confirms delivery during those specified hours, relative to the hourly amount (baseline) the customer(s) would be expected to consume during those hours, based upon recent consumption history, and the duration (hour(s)) of the agreed upon curtailment, provided that the customer supplies at least 95% of the amount confirmed for delivery.

(4) TERMS OF PROGRAM PARTICIPATION: Customers interested in participating in the program are required to sign an Agreement with the PUD. The Agreement establishes the specific terms, conditions, performance requirements and resulting billing credit associated with program participation.

(5) PROGRAM DURATION: Duration of the program will be governed by the terms of individual contracts signed with PUD program participants.

(6) PROGRAM CREDIT CONTINGENCY: Participating customers will not be entitled to a credit under this schedule for any reductions of consumption for which such customer may otherwise be compensated by the PUD.

(7) WAIVER: The PUD reserves the right to waive any one or more irregularities: (I) in a customer's pledge of an amount of hourly energy to be exchanged by the customer during an exchange event; and (II) in the deadlines set forth in the customer's Demand Exchange contract, or the PUD's confirmation of an hourly amount of energy to be exchanged by such customer during an exchange event.

Effective Date: July 24, 2001

[Res. No. 5000 (2001)]

STREET LIGHTING RATES

Schedule 1 Municipal Street Lighting Service

Schedule 3 Area Lighting Service

Schedule 4 Municipal Owned and Maintained Street Lighting Service

Schedule 5 Suburban Street Lighting Service

SCHEDULE 1 – MUNICIPAL STREET LIGHTING SERVICE

(1) AVAILABILITY: This schedule is available to counties and municipalities in all territory served by the PUD for street lighting service upon execution of a Municipal Street Lighting Contract.

This schedule provides for lighting from dusk to dawn for public streets, alleys, thoroughfares, and grounds, installed in accordance with PUD specifications.

(2) MONTHLY RATES:

~~Effective April 1, 2024~~

~~100 Watts~~	~~$6.85~~
~~200 Watts~~	~~$10.34~~
~~250 Watts~~	~~$12.19~~
~~400 Watts~~	~~$16.77~~

Effective April 1, 2025

100 Watts	$7.56
200 Watts	$11.41
250 Watts	$13.45
400 Watts	$18.51

Effective April 1, 2026

100 Watts	$8.43
200 Watts	$12.72
250 Watts	$15.00
400 Watts	$20.64

All wattages are indicative of lumens as produced by High Pressure Sodium (HPS) lamps. The District may, at its own discretion, utilize alternative lighting technologies that it determines to provide similar lighting attributes.

(3) TERMS OF SERVICE: Service under this schedule is subject to terms as defined in the Contract, the PUD's Electric Service Regulations, and to Schedule 82 which defines the PUD's Adjustments, Terms and Conditions of Service, and Limitations of Liability.

(4) TAX ADDITIONS: The above rates are subject to proportional increases to compensate for any gross revenue tax imposed by any municipal body or other governmental body having jurisdiction upon the PUD.

(5) BPA COST ADJUSTMENT: From time to time the Bonneville Power Administration ("BPA") adjusts its wholesale power and transmission rate to the PUD. At the discretion of the Commission, the rates in this Schedule may be adjusted to reflect BPA rate adjustments, either up or down, on the same date the BPA rate changes become effective. The adjusted rate will be

developed by incorporating the BPA cost change into the Electric Cost of Service Model and rate design policies adopted by the Commission in the most recent rate proceeding.

Effective Date: April 1, 2026~~5~~

[Res. No. 6205 (2025); History: 6167 (2024); 6144 (2023); 6103 (2023); 6046 (2022); 6028 (2021); 5941 (2020); 5806 (2017); 5735 (2015); 5639 (2013); 5626 (2013); 5043 (2002); 5011 (2001); 4848 (1999); 4835 (1999), 3405 (1990); 3206 (1988); 2892 (1985); 2531 (1981); 2379 (1980); 2345 (1979); 2202 (1978); 2062 (1976); 1996 (1975); 1737 (1971); 1392 (1966); 1371 (1966); 795 (1957)

SCHEDULE 3 – AREA LIGHTING SERVICE

(1) AVAILABILITY: This schedule is available in all territory served by the PUD for overhead lighting upon execution of an Area Lighting Service Contract.

This schedule provides for lighting from dusk to dawn on public or private property, installed in accordance with PUD specifications.

(2) RATE: ~~Area Street Lighting Service – Effective April 1, 2024 – 31 cents per day~~
Area Street Lighting Service – Effective April 1, 2025 – 34 cents per day
Area Street Lighting Service – Effective April 1, 2026 – 38 cents per day

(3) TERMS OF SERVICE: Service under this schedule is subject to terms as defined in the Contract, the PUD's Electric Service Regulations, and to Schedule 82 which defines the PUD's Adjustments, Terms and Conditions of Service, and Limitations of Liability.

(4) TAX ADDITIONS: The above rate is subject to proportional increases to compensate for any gross revenue tax imposed by any municipal body or other governmental body having jurisdiction upon the PUD.

(5) BPA COST ADJUSTMENT: From time to time the Bonneville Power Administration ("BPA") adjusts its wholesale power and transmission rate to the PUD. At the discretion of the Commission, the rates in this Schedule may be adjusted to reflect BPA rate adjustments, either up or down, on the same date the BPA rate changes become effective. The adjusted rate will be developed by incorporating the BPA cost change into the Electric Cost of Service Model and rate design policies adopted by the Commission in the most recent rate proceeding.

Effective Date: April 1, 2026~~5~~

[Res. No. 6205 (2025); History: 6167 (2024); 6144 (2023); 6103 (2023); 6046 (2022); 6028 (2021); 5806 (2017); 5735 (2015); 5639 (2013); 5626 (2013); 5043 (2002); 5011 (2001); 4848 (1999); 4835 (1999) 3405 (1990); 3206 (1988); 2892 (1985); 2644 (1982); 2531 (1981); 2345 (1979); 2202 (1978); 1996 (1975); 1392 (1966); 1371 (1966); 795 (1957)]

SCHEDULE 4 – MUNICIPAL OWNED AND MAINTAINED STREET LIGHTING SERVICE

(1) AVAILABILITY: This schedule is available to counties and municipalities in all territory served by the PUD for municipally owned and maintained street lighting service upon execution of a Municipally Owned and Maintained Street Lighting Contract.

(2) MONTHLY RATES:

Schedule 4 – HIGH PRESSURE SODIUM LAMPS (HPS)

~~Effective April 1, 2024~~

~~100 Watts~~	~~$5.00~~
~~150 Watts~~	~~$6.48~~
~~200 Watts~~	~~$8.86~~
~~250 Watts~~	~~$11.93~~
~~400 Watts~~	~~$18.36~~

Effective April 1, 2025

100 Watts	$5.52
150 Watts	$7.15
200 Watts	$9.78
250 Watts	$13.17
400 Watts	$20.26

Effective April 1, 2026

100 Watts	$6.15
150 Watts	$7.97
200 Watts	$10.90
250 Watts	$14.68
400 Watts	$22.59

Schedule 4 – LIGHT EMITTING DIODES (LEDs)

~~Effective April 1, 2024~~

~~0~~	~~-~~	~~20~~	~~Watts~~	~~$0.75~~
~~20.01~~	~~-~~	~~40~~	~~Watts~~	~~$1.52~~
~~40.01~~	~~-~~	~~60~~	~~Watts~~	~~$2.26~~
~~60.01~~	~~-~~	~~80~~	~~Watts~~	~~$3.03~~
~~80.01~~	~~-~~	~~100~~	~~Watts~~	~~$3.79~~
~~100.01~~	~~-~~	~~120~~	~~Watts~~	~~$4.55~~
~~120.01~~	~~-~~	~~140~~	~~Watts~~	~~$5.31~~

~~140.01~~	~~-~~	~~160~~	~~Watts~~	~~$6.06~~
~~160.01~~	~~-~~	~~180~~	~~Watts~~	~~$6.81~~
~~180.01~~	~~-~~	~~200~~	~~Watts~~	~~$7.57~~
~~200.01~~	~~-~~	~~220~~	~~Watts~~	~~$8.36~~
~~220.01~~	~~-~~	~~240~~	~~Watts~~	~~$9.09~~
~~240.01~~	~~-~~	~~260~~	~~Watts~~	~~$9.46~~
~~260.01~~	~~-~~	~~280~~	~~Watts~~	~~$10.59~~
~~280.01~~	~~-~~	~~300~~	~~Watts~~	~~$11.36~~

Effective April 1, 2025

0	-	20	Watts	$0.83
20.01	-	40	Watts	$1.68
40.01	-	60	Watts	$2.49
60.01	-	80	Watts	$3.34
80.01	-	100	Watts	$4.18
100.01	-	120	Watts	$5.02
120.01	-	140	Watts	$5.86
140.01	-	160	Watts	$6.69
160.01	-	180	Watts	$7.52
180.01	-	200	Watts	$8.35
200.01	-	220	Watts	$9.23
220.01	-	240	Watts	$10.03
240.01	-	260	Watts	$10.44
260.01	-	280	Watts	$11.69
280.01	-	300	Watts	$12.54

Effective April 1, 2026

0	-	20	Watts	$0.93
20.01	-	40	Watts	$1.87
40.01	-	60	Watts	$2.78
60.01	-	80	Watts	$3.72
80.01	-	100	Watts	$4.66
100.01	-	120	Watts	$5.60
120.01	-	140	Watts	$6.53
140.01	-	160	Watts	$7.46
160.01	-	180	Watts	$8.38
180.01	-	200	Watts	$9.31
200.01	-	220	Watts	$10.29
220.01	-	240	Watts	$11.18
240.01	-	260	Watts	$11.64
260.01	-	280	Watts	$13.03
280.01	-	300	Watts	$13.98

(3) TERMS OF SERVICE: Service under this schedule is subject to terms as defined in the Contract, the PUD's Electric Service Regulations, and to Schedule 82 which defines the PUD's

Adjustments, Terms and Conditions of Service, and Limitations of Liability.

(4) TAX ADDITIONS: The above rates are subject to proportional increases to compensate for any gross revenue tax imposed by any municipal body or other governmental body having jurisdiction upon the PUD.

(5) BPA COST ADJUSTMENT: From time to time the Bonneville Power Administration ("BPA") adjusts its wholesale power and transmission rate to the PUD. At the discretion of the Commission, the rates in this Schedule may be adjusted to reflect BPA rate adjustments, either up or down, on the same date the BPA rate changes become effective. The adjusted rate will be developed by incorporating the BPA cost change into the Electric Cost of Service Model and rate design policies adopted by the Commission in the most recent rate proceeding.

Effective Date: April 1, 2026~~5~~

[Res. No. 6205 (2025); History: 6167 (2024); 6144 (2023); 6103 (2023); 6046 (2022); 6028 (2021); 5941 (2020); 5806 (2017); 5626 (2016); 5735 (2015); 5626 (2015); 5626 (2014); 5639 (2013); 5626 (2013); 5043 (2002); 5011 (2001); 4848 (1999); 4835 (1999), 3405 (1990); 3168 (1988)]

SCHEDULE 5 – SUBURBAN STREET LIGHTING SERVICE

(1) APPLICABILITY: This schedule applies to Customers having metered electric services that are located within a Suburban Street Lighting Service Area established by Public Utility PUD No. 1 of Snohomish County. Customers that have financial responsibility for metered electric service, shall be charged for street lighting service under the provisions of this schedule.

(2) SERVICE PROVIDED: This schedule sets forth the rates charged by the PUD for the service of providing local area lighting from dusk to dawn for streets, alleys, thoroughfares, and grounds, as approved by the PUD and installed in accordance with PUD specifications. As this service is local in nature, the PUD does not undertake to provide this service at large or to the public generally. Current PUD policy also excludes all areas within incorporated cities.

(3) SUBURBAN STREET LIGHTING SERVICE UNIT: A Suburban Street Lighting Service Unit is the unit of lighting service provided under this schedule, based upon the currently most just, fair and reasonable approximation of quantifying this service in consideration of its nature. Responsibility for metered electric service located within a Suburban Street Lighting Service Area shall include one or more Suburban Street Lighting Service Units per month as described below in this paragraph (3).

Metered Electric Service Within a Suburban Street Lighting Service Area Provides Electricity to	Number of Suburban Street Lighting Service Units Charged per Month
Single Family Residence.	1 Unit
Dwelling Unit within a Multi-Family Residence. (For example: an apartment, an individual unit in a condominium, duplex or triplex).	1 Unit
Accessory Areas associated with Multi-Family Dwellings. Metered electric service to areas not used as a dwelling unit (For example: hallway lighting, laundry rooms, recreation rooms, other common areas, offices, supply rooms, maintenance shops, grounds and parking areas).	1 Unit per metered electric service
Other Dwellings and Abodes. (For example: Boats, Trailers, RVs).	1 Unit
All Other Uses.	1 Unit per metered electric service

Where a residential customer is financially responsible for more than one metered electric service located on a single property and one of the services provides electricity to a single family residence, other dwelling or an abode as described above, that customer shall be charged one (1) unit per month for each single family residence, and any other dwelling or abode served and shall not be charged additional Suburban Street Lighting Service Units for any metered electric services providing electricity to systems supporting the same single family residence (for example water and septic systems), or to associated outbuildings such as garages, sheds and barns not used for commercial or business purposes.

The PUD shall determine, at its sole discretion but subject to this schedule, whether or not a metered electric service located within the Suburban Street Lighting Service Area is subject to a Suburban Street Lighting Service Unit charge.

(4) MONTHLY RATES: One (1) Suburban Street Lighting Service Unit –

~~Effective April 1, 2024 - $2.09 per month~~
Effective April 1, 2025 - $2.31 per month
Effective April 1, 2026 - $2.57 per month

(5) TERMS OF SERVICE: Service under this schedule is subject to terms as defined in the Contract, the PUD's Electric Service Regulations, and to Schedule 82 which defines the PUD's Adjustments, Terms and Conditions of Service, and Limitations of Liability.

(6) TAX ADDITIONS: The above rates are subject to proportional increases to compensate for any gross revenue tax imposed by any municipal body or other governmental body having jurisdiction upon the PUD.

(7) BPA COST ADJUSTMENT: From time to time the Bonneville Power Administration ("BPA") adjusts its wholesale power and transmission rate to the PUD. At the discretion of the Commission, the rates in this Schedule may be adjusted to reflect BPA rate adjustments, either up or down, on the same date the BPA rate changes become effective. The adjusted rate will be developed by incorporating the BPA cost change into the Electric Cost of Service Model and rate design policies adopted by the Commission in the most recent rate proceeding.

Effective Date: April 1, 2026~~5~~

[Res. No. 6205 (2025); History: 6167 (2024); 6144 (2023); 6103 (2023); 6046 (2022); 6028 (2021); 5806 (2017); 5735 (2015); 5639 (2013); 5626 (2013); 5192 (2004)]

SNOHOMISH PUD

Energizing Life In Our Communities

Cost-of-Service Analysis and Preliminary Rate Design 2026

November 18, 2025

Peter Dauenhauer, Senior Manager Rate, Economics & Energy Risk Management
Christina Leinneweber, Principal Economist

» **Previous Presentations**:

- September 9, 2025: 2026 Budget Highlights and Initial Cost-of-Service Analysis (COSA)
- October 6, 2025: 2026 Proposed Budget and Cost-of-Service Analysis (COSA)
- November 4, 2025: Cost-of-Service Analysis and Preliminary Rates Design 2026
- June 27, 2019: Snohomish PUD Rate Redesign Commission Workshop

This Presentation

Purpose of the Presentation

- Address considerations raised at the November 4, 2025, Commission briefing.
- Present 2026 rate adjustment options based on the most recent Budget and Cost-of-Service Analysis (COSA).
- Present considerations for the Commission regarding alternative rate designs.
- Informational Only.

Agenda

- Cost-of-Service Analysis (COSA)
- Potential Rate Adjustments:
  - Residential Rate Design
  - Commercial Rate Design
  - Other Rate Design
- Other Rate Design Questions
- Next Steps

Recent & Upcoming Meetings

- July 21, 2025: Cost-of-Service and Rates Design Workshop
- September 9, 2025: 2026 Budget & Preliminary Cost-of-Service Results
- October 6, 2025: 2026 Proposed Budget and Cost-of-Service Analysis (COSA)
- November 4, 2025: Cost-of-Service Analysis and Preliminary Rate Design
- November 18, 2025: Rate Design Considerations & Open Public Hearing
- December 2, 2025: Close Public Hearing & Request Commission Approval

NEW RATES EFFECTIVE: APRIL 1, 2026

Cost-of-Service Analysis

Recap

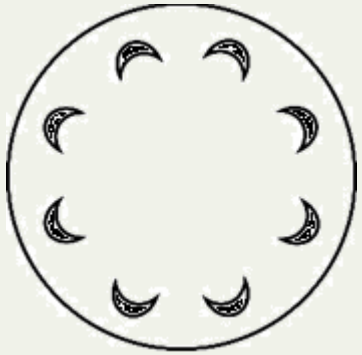
Revenue Requirement: What are Costs?

Revenue Requirement
"How much money does the utility need?"

Cost-of-Service Analysis
"Who pays what?"

Rate Design
"How do customers pay?"

- Identifies revenues needed for operations.
- Budget + next four years + policy-driven adjustments.
- Ensures achievement of key policy objectives such as fund balances.



How big is the pie?
What is in the pie?

2.5% System-Average Increase.

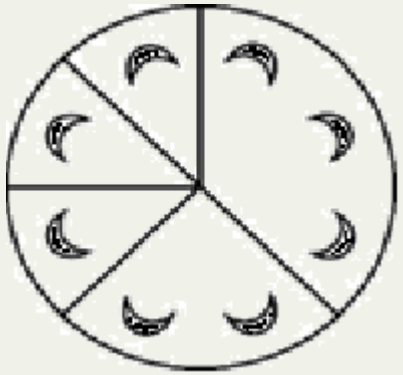
COSA: Who Causes Costs?

Revenue Requirement
"How much money does the utility need?"

Cost-of-Service Analysis
"Who pays what?"

Rate Design
"How do customers pay?"

- Determines total to be paid by each customer class.



How big is each slice of the pie?

2.8% Residential Increase.

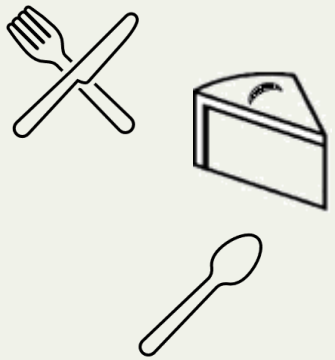
Rate Design: How Do Customers Pay?

Revenue Requirement
"How much money do we need?"

Cost-of-Service Analysis
"Who pays what?"

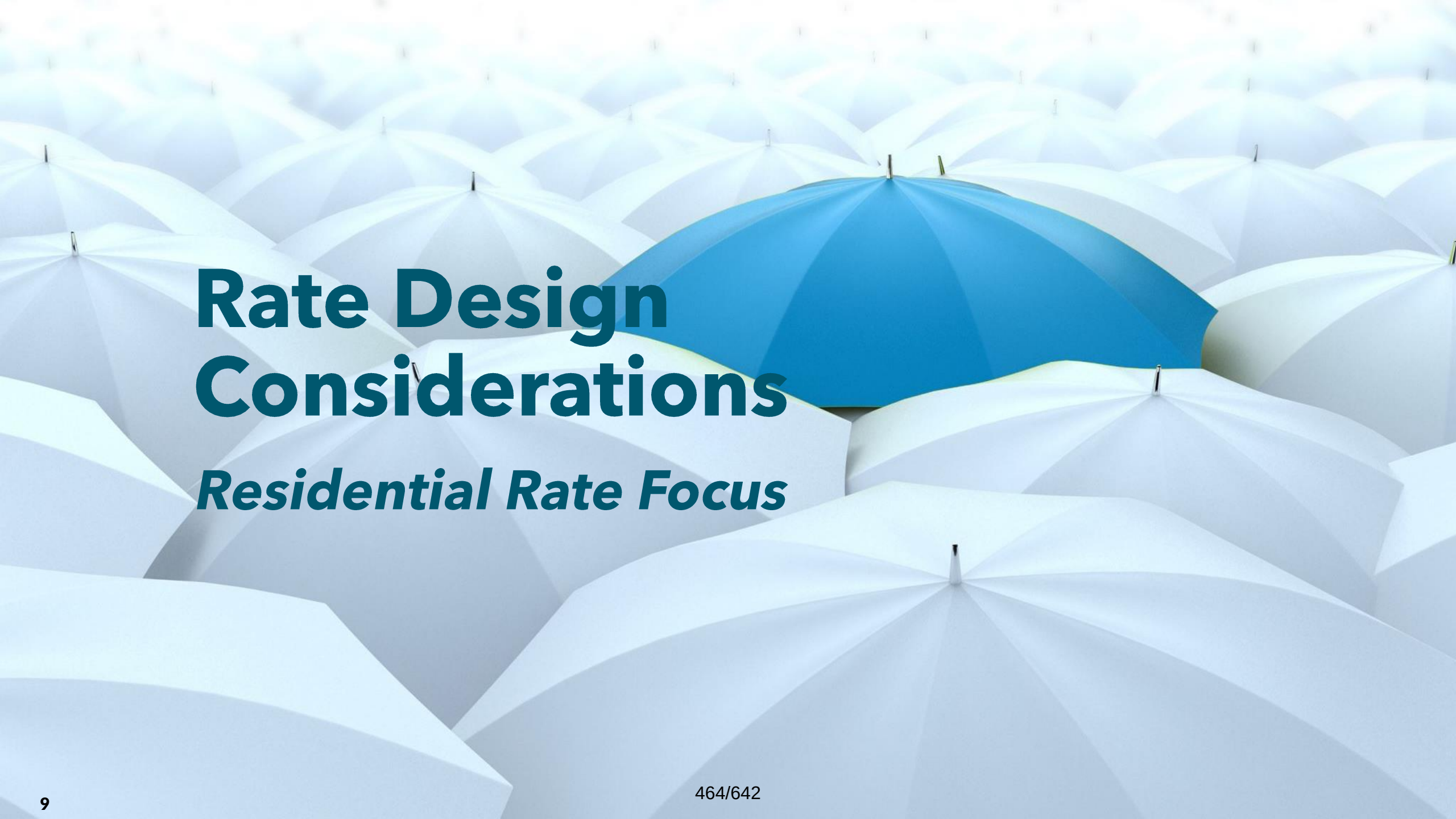
Rate Design
"How do customers pay?"

Increase fixed daily charge, energy charge, or both?



- Design rate structure to collect revenue from customers in class.
- Set actual cents per kWh, base charge per month, etc.

How to Eat the Pie?

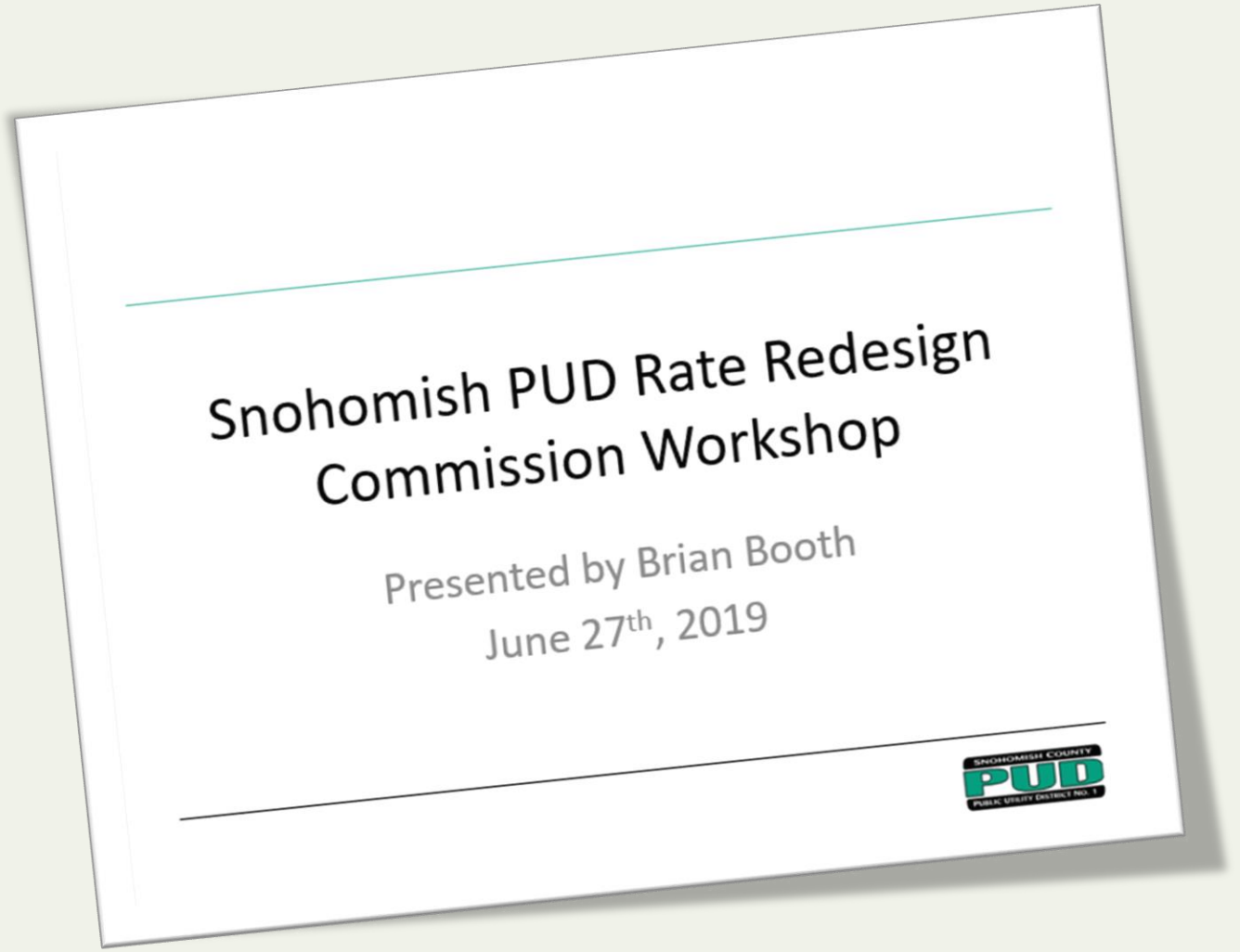


Rate Design Considerations

Residential Rate Focus

Rate Design Principles

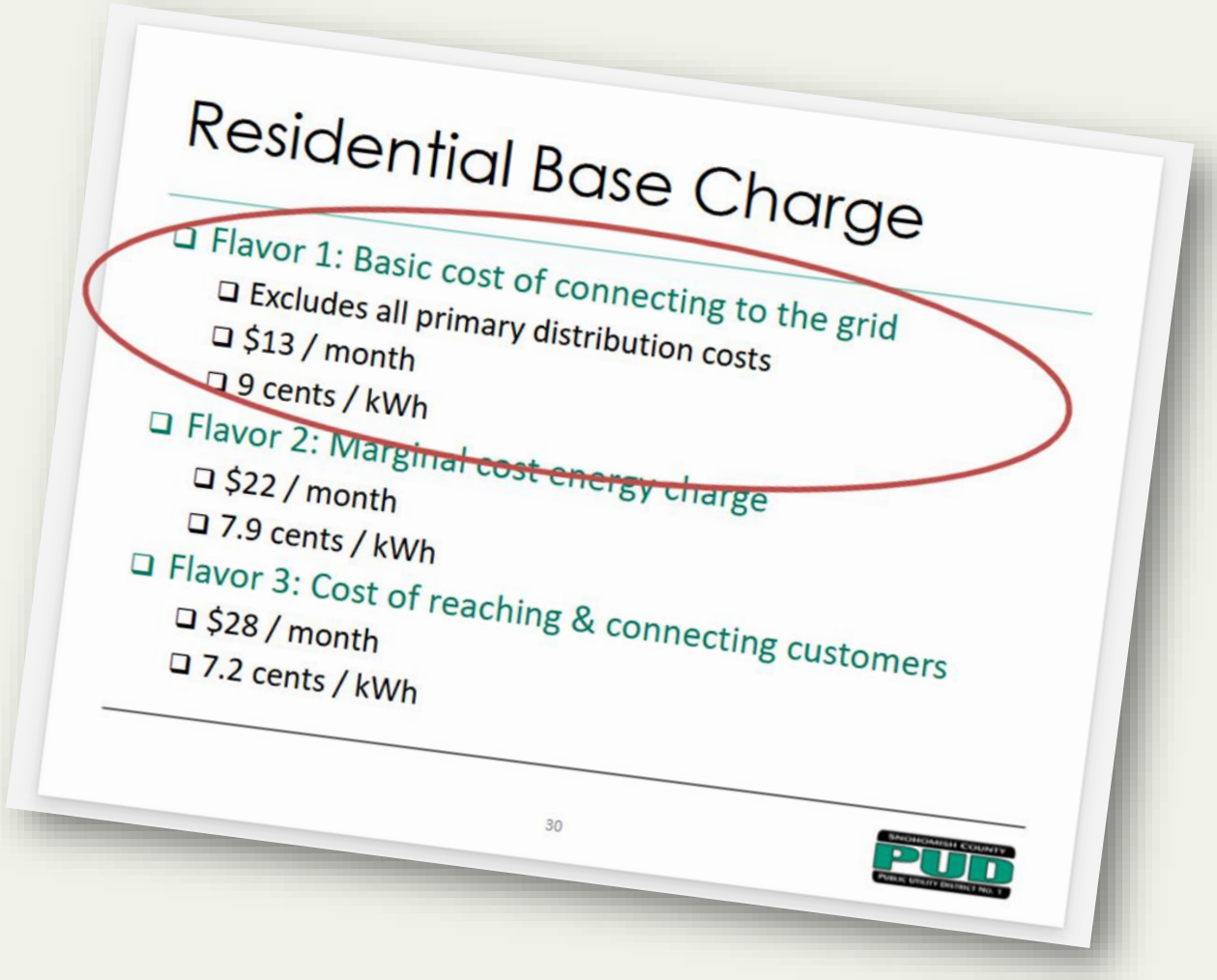
1. Rates should **fairly apportion the utility's cost of service** among consumers.
2. Rates should **promote economic & energy efficiency** in the use of energy, competing products, and conservation.
3. Rates should **be practical**.
4. Design should **promote stability** of rates and revenues.



Adapted From James C. Bonbright, *Principles of Public Utility Rates.*

Rate Options Considered (2019)

- Increased Minimum Bill
- Single Base Charge
- Base Charge by Service Size
- Inclining Block *(price goes up as people use more)*
- Declining Block *(price goes down as people use more)*
- Seasonal Rates
- Residential Demand Charges



Benefits of Service Size Differentials

- Better **reflects the cost** to serve different customers.
- **Practical** and understandable way to improve cost recovery.
- **Mitigates downsides** of fixed base charges:
  - Smaller panels **correlate with lower usage.**
  - Encourages customers to **consider conservation** when building/remodeling.
- **Provides additional recovery flexibility** as we prepare for electrification (potential EV load) or ease transition to 3-part rate structures.

Residential Rate Design

Implementation

Options for +2.8% Residential Change

Updated Staff Recommendation

	Current (April 2025)	Flavor 1 *(Fixed Connection Cost Only)*	Full Fixed Distribution/Grid Cost	Alternative A	*Recovery of Fixed Grid Cost (A)*	Alternative B	*Recovery of Fixed Grid Cost (B)*	Alternative C	*Recovery of Fixed Grid Cost (C)*
Small *(Multifamily & ≤100 amp)*	*49¢*	54¢	$1.46	59¢	*40%*	49¢	*34%*	50¢	*34%*
Medium *(100 < amp ≤200)*	*80¢*	56¢	$1.48	91¢	*61%*	80¢	*54%*	82¢	*55%*
Large *(200 < amp ≤400)*	*$1.14*	76¢	$1.68	$1.25	*74%*	$1.14	*68%*	$1.17	*70%*
X-Large *(>400 amp)*	*$1.86*	$1.71	$2.63	$2.01	*76%*	$1.86	*71%*	$1.91	*73%*
Energy (per kWh)	*10.263¢*	11.061¢	8.115¢	10.263¢		10.613¢		10.550¢	

2019 Updated Goal

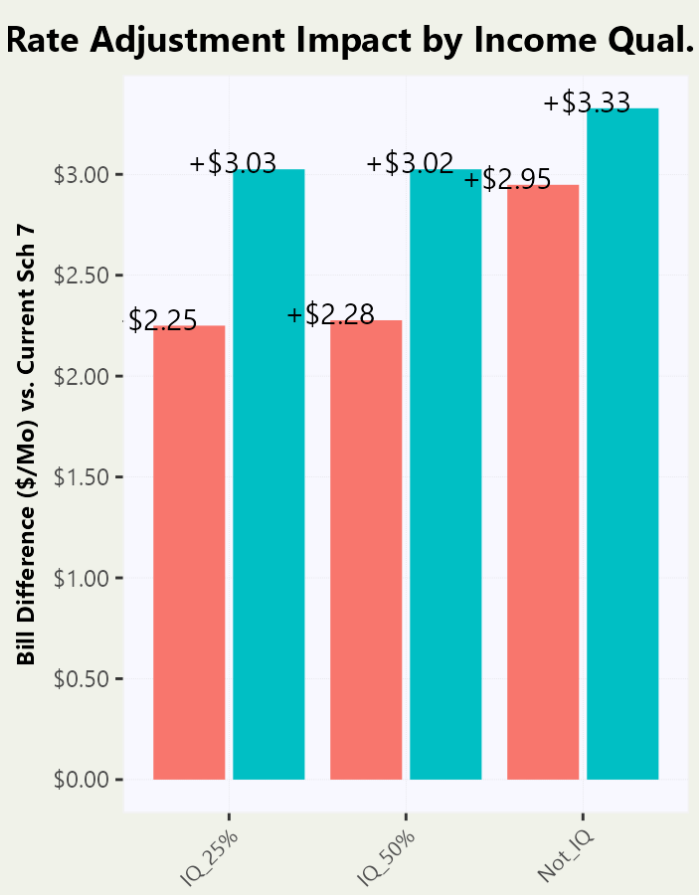
Draft and Subject to Change.

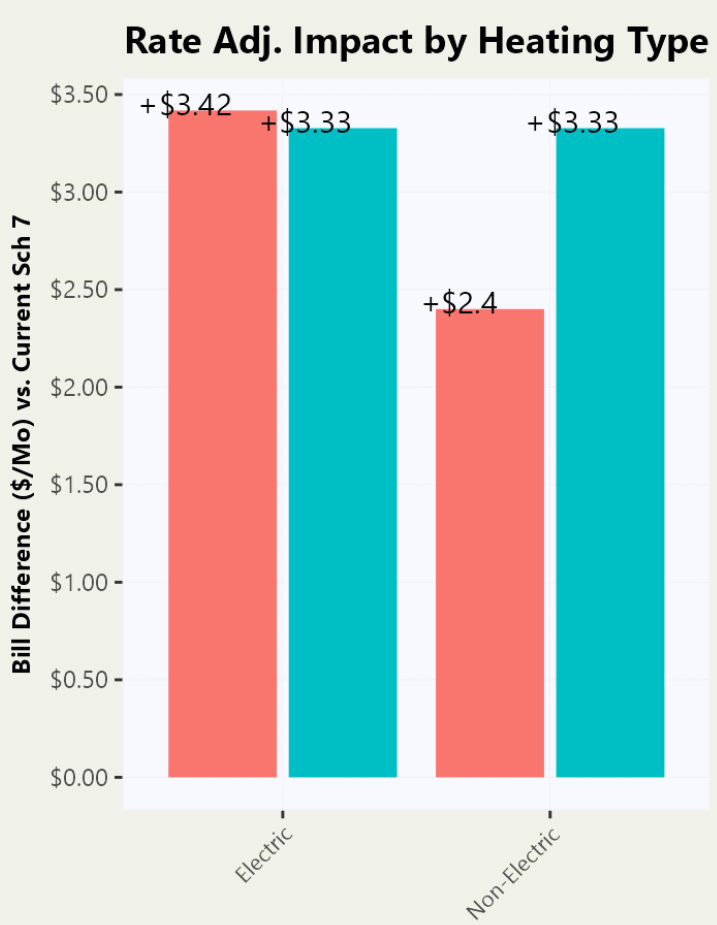
Residential Rate Adjustment Impact by Customer Groups vs. Current Rates

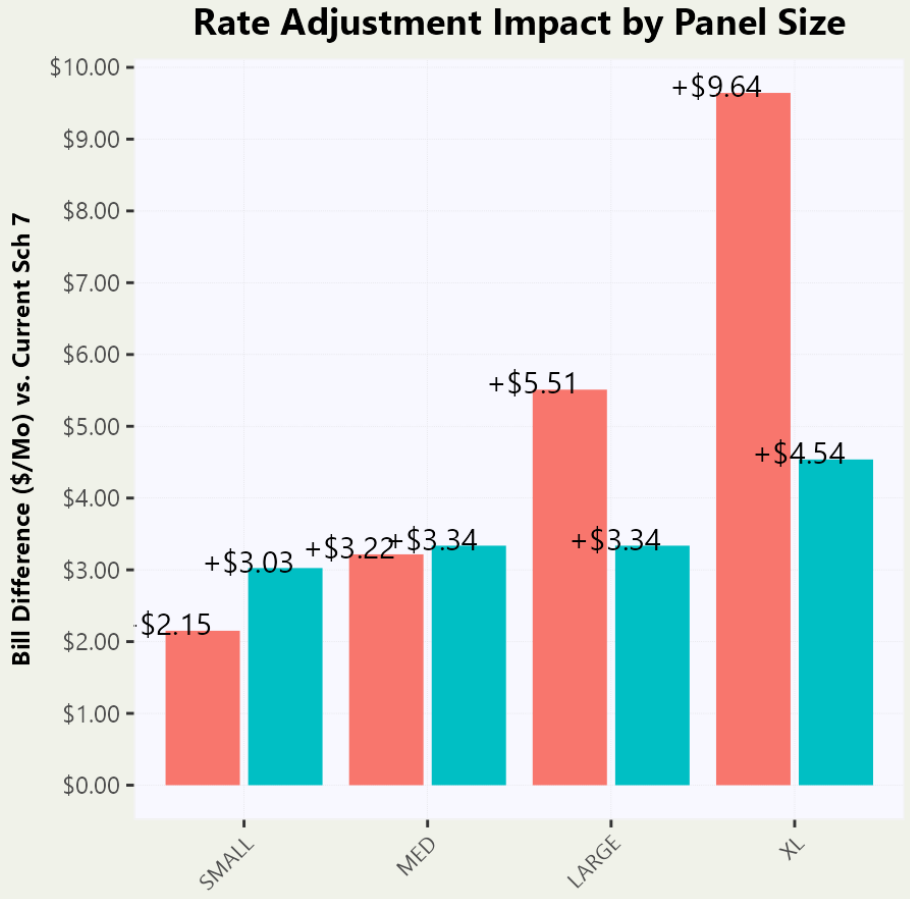
Key

If Energy Charge Only

If Base Charge Only







Commercial Rate Designs

Implementation

Small General Service

Schedule 25 *1.9% Increase*	Current 2025 Rate ⇒ Proposed 2026 Rate		*Δ*
Base Charge **(per Day)**	$1.72	$1.72	*0¢*
Energy Charge **(per kWh)**	8.365¢	8.572¢	*0.207¢*

- Example: coffee shop, mom & pop retail, storefront, church.
- Implement rate increase in the energy charge.

Draft and Subject to Change.

Medium General Service

Schedule 20 *1.2% Increase*	Current 2025 Rate	⇒ Proposed 2026 Rate	Δ
Base Charge (per Day)	$2.10	$4.85	*$2.75*
Demand Charge (per peak kW)	$7.16	$7.21	*5.0¢*
Energy Charge (per kWh)	8.365¢	8.365¢	*0.0¢*

- Example: large grocery store, large restaurant, church campus, small manufacturing.
- Implement rate increase primarily in the base charge.
- Improves alignment with COSA.

Draft and Subject to Change.

Legacy Time of Use

Schedule 24 *0.0% Increase*	Current 2025 Rate	⇒	Proposed 2026 Rate	Δ
Base Charge (per Day)	$2.10		$2.10	*0¢*
Demand Charge (per peak kW between 7 a.m. and 11 a.m. Monday through Saturday)	$10.48		$10.48	*$0.00*
Energy Charge (per kWh)	8.365¢		8.365¢	*0¢*

Move remaining customer to next-generation time-of-use rate as soon as available.

Draft and Subject to Change.

Special Continuous Service

Schedule 23 *8.7% Increase*	Current 2025 Rate	⇒	Proposed 2026 Rate	Δ
Base Charge (per Day)	65¢		74¢	*9¢*
Energy Charge (per kWh)	9.000¢		9.000¢	*0.0¢*

- Example: wireless attachments to poles.
- Very small total revenue.

Draft and Subject to Change.

Industrial Rate Designs

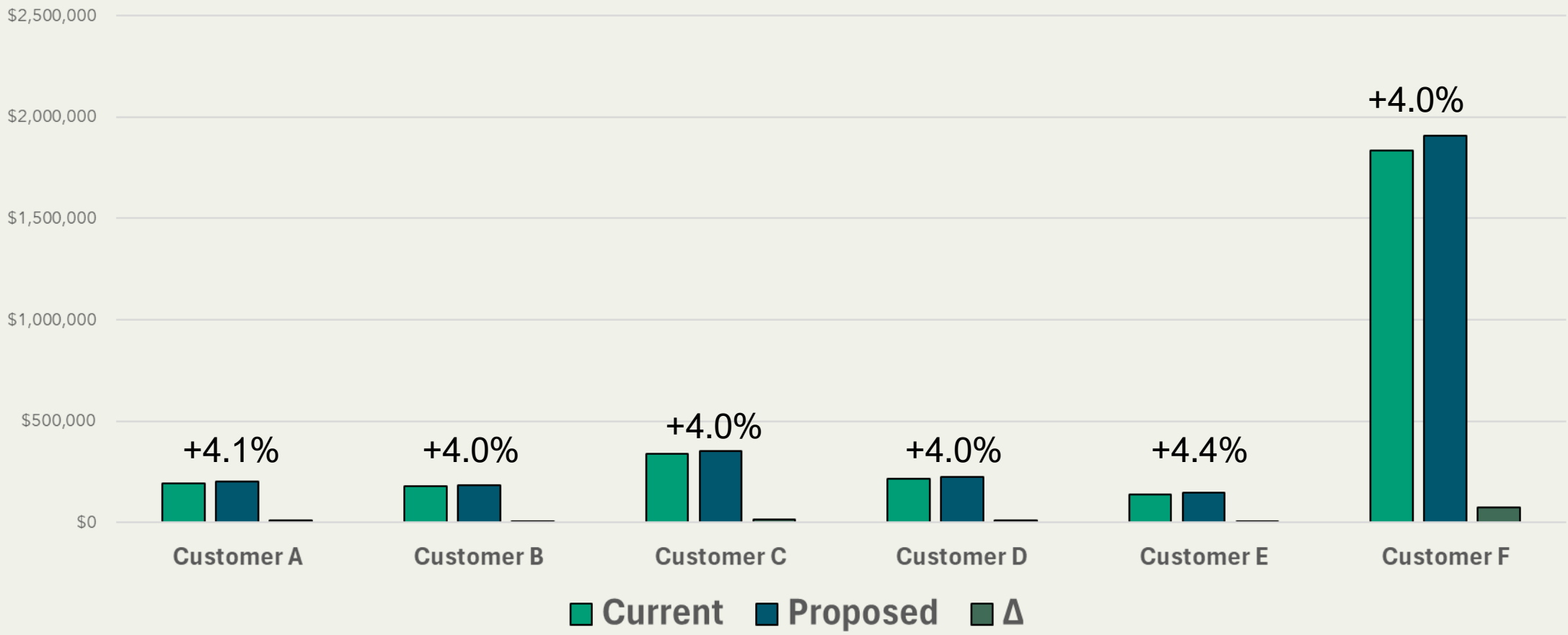
Implementation

Large Primary Service

Schedule 36 *4.0% Increase*	Current 2025 Rate	⇒	Proposed 2026 Rate	*Difference*
Demand Charge (per peak kW)	$5.94		$6.35	*41¢*
Energy Charge (per kWh)	6.630¢		6.862¢	*0.232¢*
Minimum Charge (per Month)	$10,500.00		$10,500.00	*$0.00*

Net effect: 4.0% increase for average customer.

Large Primary Monthly Bills (Average)



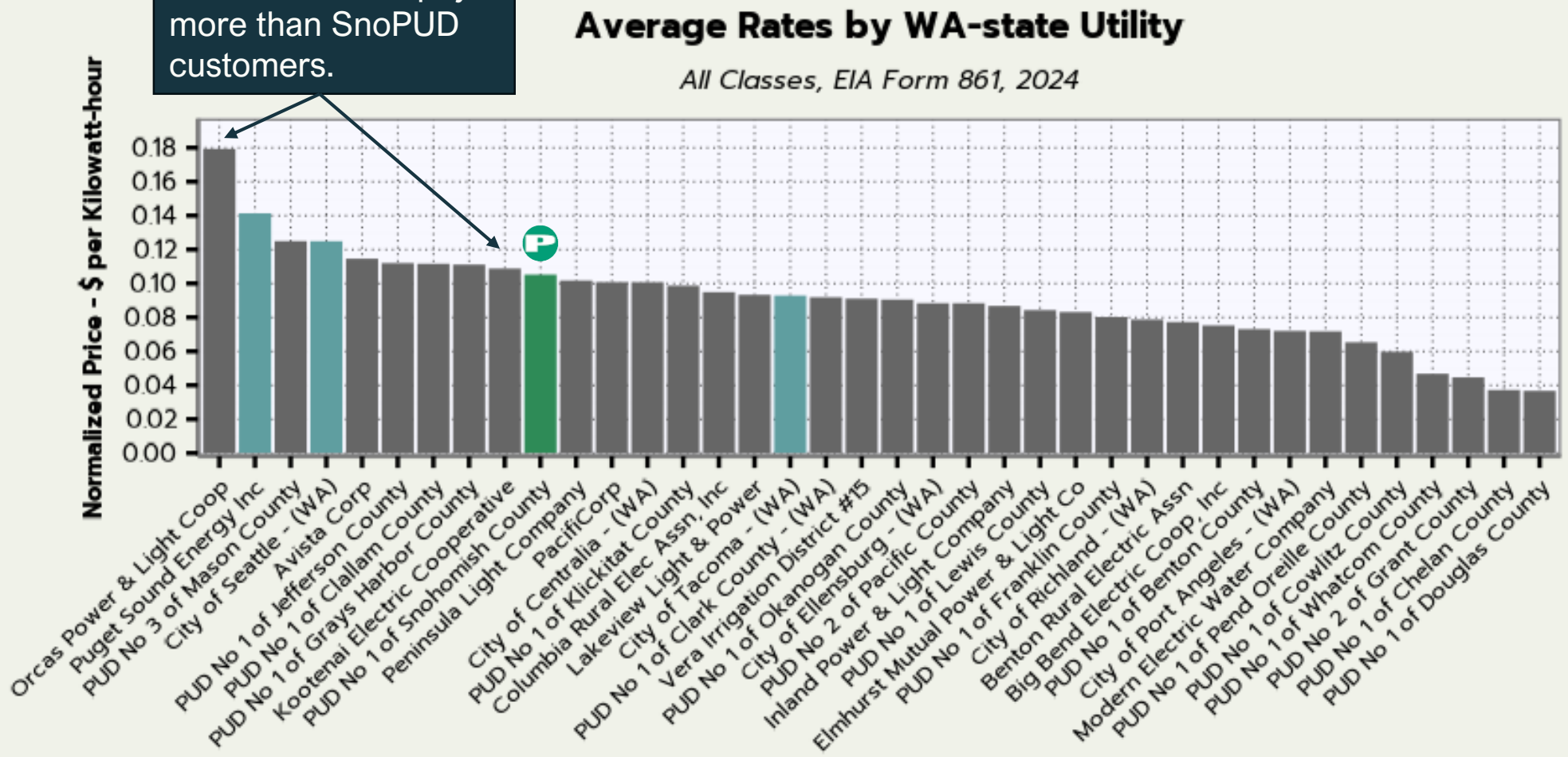
Large 115 kV Service

Schedule 38	Current 2025 Rate	⇒	Proposed 2026 Rate	*Difference*
Demand Charge (per peak kW)	$5.35		$5.72	*37¢*
Energy Charge (per kWh)	6.563¢		6.794¢	*0.231¢*
Minimum Charge (per Month)	$7,500.00		$7,500.00	*$0.00*

No customers are currently served on this rate.

Rate Comparison - 2024

2/3 of Washington state customers pay more than SnoPUD customers.



Next Steps

- Public Hearing: November 18, 2025
- Board Consideration: December 2, 2025
- New Rates in Effect: April 1, 2026



Appendix

Snohomish PUD Rate Classes

- Single family & multifamily
- Average customer uses ~11,600 kWh per year
- ⅔ of retail revenue

Residential (7)



- Boutiques, banks, churches
- Under 100 kW peak
- Average ~27,500 kWh per year

General-Small (25)



- Grocery stores, hotels, light industry
- Over 100 kW peak
- Average ~932,000 kWh per year

General-Medium (20)



- Peak over 5,000 kW
- Average ~78,000,000 kWh per year

Large Primary (36)



- Street & traffic
- Municipalities & neighborhoods

Lighting (1/3/4/5)



- Telecom providers, utility providers
- Special attachments
- Average ~2,200 kWh per year

Special Continuous (23)



- Manufacturing
- Seasonal legacy rate
- Average ~388,000 kWh per year
- Smallest class

Legacy Time-of-Use (24)



Recommendation

Rate Revenue *(in millions)*	SYSTEM	Residential (7)	General - Medium (20)	General - Small (25)	Large Primary (36)	Special Continuous (23)	Legacy Time-of-Use (24)	Lighting (1/3/ 4/5)
		--------AT CURRENT REVENUE LEVELS--------						
at Existing Rates	**$751.9**	$471.9	$150.5	$88.8	$34.7	$1.4	$0.1	$4.5
at Cost-of-Service Rates		$494.9	$131.4	$80.9	$36.3	$1.5	$0.0	$6.9
difference		*4.9%*	*-12.7%*	*-8.9%*	*4.4%*	*6.1%*	*-26.7%*	*54.6%*
		--------AT SUGGESTED REVENUE LEVELS--------						
at Cost of Service	**$770.6**	$507.3	$134.7	$82.9	$37.2	$1.5	$0.1	$7.1
Cost-of-Service Adjustment	***2.5%***	*7.5%*	*-10.5%*	*-6.6%*	*7.0%*	*8.7%*	*-24.8%*	*58.5%*
2026 Recommendation	2.5%	2.8%	1.2%	1.9%	4.0%	8.7%	0.0%	11.5%
Remaining to Adjust		4.7%	-11.8%	-8.6%	3.0%	0.0%	-24.8%	0.0%

Municipal Street Lighting

Schedule 1 *11.5% Increase*	Current 2025 Rate	⇒	Proposed 2026 Rate
100 Watts	$7.56 *per month*		$8.43 *per month*
200 Watts	$11.41		$12.72
250 Watts	$13.45		$15.00
400 Watts	$18.51		$20.64

Draft and Subject to Change.

Area Lighting

Schedule 3 *11.5% Increase*	Current 2024 Rate	⇒	Proposed 2025 Rate
Per Day	$0.34		$0.38

Draft and Subject to Change.

Municipal-Owned Lighting

Schedule 4 *High-Pressure Sodium* *11.5% Increase*	Current 2025 Rate	⇒	Proposed 2026 Rate
100 Watts	$5.52 *per month*		$6.15 *per month*
150 Watts	$7.15		$7.97
200 Watts	$9.78		$10.90
250 Watts	$13.17		$14.68
400 Watts	$20.26		$22.59

Draft and Subject to Change.

Municipal-Owned Lighting

Schedule 4 *Light-Emitting Diodes* *11.5% Increase*	Current 2025 Rates	⇒	Proposed 2026 Rate
0 to 20 Watts	$0.83 *per day*		$0.93 *per day*
20.01 to 40 Watts	$1.68		$1.87
40.01 to 60 Watts	$2.49		$2.78
60.01 to 80 Watts	$3.34		$3.72
80.01 to 100 Watts	$4.18		$4.66
100.01 to 120 Watts	$5.02		$5.60
120.01 to 140 Watts	$5.86		$6.53
140.01 to 160 Watts	$6.69		$7.46
160.01 to 180 Watts	$7.52		$8.38
180.01 to 200 Watts	$8.35		$9.31
200.01 to 220 Watts	$9.23		$10.29
220.01 to 240 Watts	$10.03		$11.18
240.01 to 260 Watts	$10.44		$11.64
260.01 to 280 Watts	$11.69		$13.03
280.01 to 300 Watts	$12.54		$13.98

Draft and Subject to Change.

Suburban Street Lighting

Schedule 5 *11.5% Increase*	Current 2025 Rate	⇒	Proposed 2026 Rate
Per Month Per Service Unit	$2.31		$2.57

Draft and Subject to Change

Public Electric Vehicle Chargers

Schedule 20EV	Current 2025 Rate	⇒	Proposed 2026 Rate
Base *(per Day)*	$2.10		$4.85
Energy First 30,000 kWh *(per kWh)*	$0.0900		$0.08365
Minimum Charge	$2.27 per day +$0.01707 per kW>10 per day		$2.27 per day +$0.01707 per kW>10 per day

Public Electric Vehicle Chargers

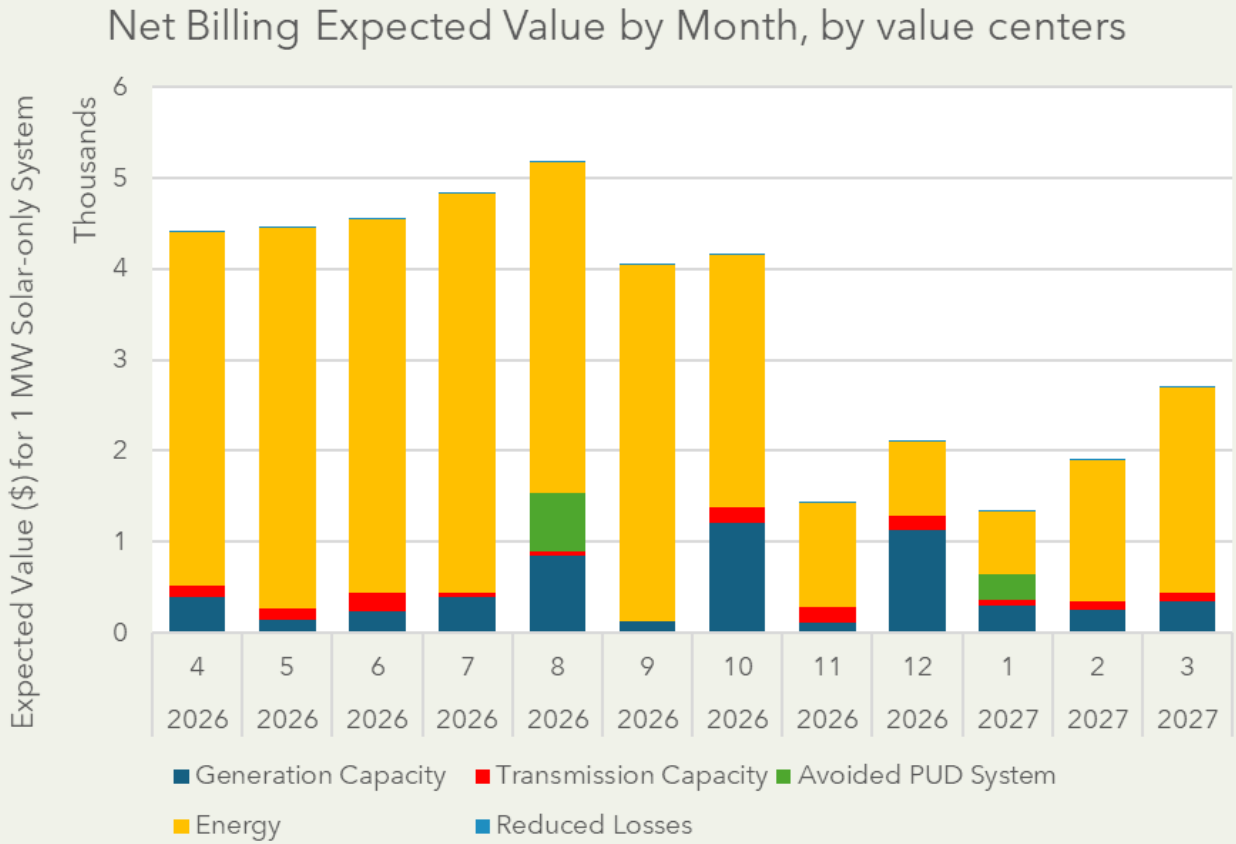
Energy *30,000+ kWh*	Current *per kWh*	⇒	Proposed *per kWh*
April 1, 2025	$0.08462		$0.08462
January 1, 2026	$0.08446		$0.08446
April 1, 2026	$0.08446		$0.08430
January 1, 2027	$0.08430		$0.08430
January 1, 2028	$0.08413		$0.08413
January 1, 2029	$0.08397		$0.08397
January 1, 2030	$0.08381		$0.08381
January 1, 2031	$0.08365		$0.08365

Demand *100+ kW*	Current *per kW*	⇒	Proposed *per kW*
April 1, 2025	$3.86		$3.86
January 1, 2026	$4.41		$4.41
April 1, 2026	$4.41		$4.97
January 1, 2027	$4.96		$4.97
January 1, 2028	$5.51		$5.53
January 1, 2029	$6.06		$6.09
January 1, 2030	$6.61		$6.65
January 1, 2031	$7.16		$7.21

Draft and Subject to Change.

Sch201 Net Billing

- Updated valuation Post-Load Following.



2026 Budget Net Billing Rate

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2025	3.830	3.830	3.830	2.970	2.970	4.110	4.110	4.110	4.110	2.970	3.830	3.830
2026	3.830	3.830	3.830	**4.605**	**4.605**	**3.956**	**3.956**	**3.956**	**3.956**	**4.605**	**4.381**	**4.381**
2027	**4.381**	**4.381**	**4.381**									

new solar-only rates starting 4/1/26 **transition** **summer** **winter**

all prices: ¢/kWh

Draft and Subject to Change.

BUSINESS OF THE COMMISSION

Meeting Date: December 2, 2025 **Agenda Item:** 8A

TITLE

Consideration of a Motion Accepting the Annual Financial Planning and Budgeting Monitoring Report

SUBMITTED FOR: Items for Individual Consideration

Finance Division	Sarah Bond	8448
Department	*Contact*	*Extension*

Date of Previous Briefing: _____

Estimated Expenditure: _____ Presentation Planned ☐

ACTION REQUIRED:

☐ Decision Preparation
☐ Policy Discussion
☐ Policy Decision
☐ Statutory

☐ Incidental (Information)

☒ Monitoring Report

SUMMARY STATEMENT:

Identify the relevant Board policies and impacts:

Executive Limitation 4 – Financial Planning and Budgeting

List Attachments:
Internal Monitoring Report – Financial Planning and Budgeting (EL-4)

GOVERNANCE
INTERNAL MONITORING REPORT

Report Date: December 2, 2025 **Policy Type:** Executive Limitations

Reporting Method: ☒ **Executive Report** ☐ **External Audit** ☐ **Direct Inspection**

Policy Title: Financial Planning and Budgeting (EL-4)

Date of Policy: April 16, 2024 **Frequency:** Annually

Executive Limitations: *The District's multi-year financial plan shall not deviate materially from the Board's Ends priorities or risk fiscal jeopardy. The District's annual budget shall be derived from a multi-year plan of at least five years.*

Interpretation: The District will prepare a multi-year financial plan that is fiscally responsible and consistent with the Board's Ends priorities.

Compliance: This report constitutes my assurance that, as reasonably interpreted, the District is in material compliance with these conditions as of December 2, 2025.

Summary Data: A proposed budget and multi-year forecast, along with key assumptions, was provided and discussed with the Board during the October 21, 2025 public hearing.

Signed John A Haarlow 11/23/2025
John A. Haarlow, CEO/General Manager Date

Signed Jeff Bishop 11/20/2025
Jeff Bishop, Chief Financial Officer Date

Executive Limitation 1: *Accordingly, the CEO/Manager shall not allow financial planning/budgeting which fails to include credible projection of revenues and expenses, separation of capital and operations items, cash flow, and disclosure of planning assumptions.*

Interpretation: The proposed budget and five-year forecast will be prepared with realistic projections of revenues and expenditures, separation of capital and operational items, cash flow, and disclosure of planning assumptions.

Conclusion: This Executive Limitation was followed with no known exceptions.

Summary Data: Staff provided the Board with a proposed budget and multi-year forecast during the October 21, 2025 public hearing.

Executive Limitation 2: *Accordingly, the CEO/General Manager shall not allow financial planning/budgeting which allows Unrestricted Funds to be budgeted below the required 180-days or allows actual Unrestricted Funds to fall below the 165-day floor during an operating year, beginning in budget year 2027.*

Interpretation: The proposed budget and five-year forecast will be prepared to ensure that Unrestricted funds stay above the required 180-days.

Conclusion: The District's financial reserve policies mandate operating reserves above this Executive Limitation.

Summary Data: The proposed budget and multi-year forecast presented at the October 21, 2025 public hearing included reserve projections above this 180-day requirement beginning in 2027.

Executive Limitation 3: *Accordingly, the CEO/General Manager shall not allow financial planning/budgeting which provides less for Board prerogatives during the year than is set forth in the Cost of Governance policy.*

Interpretation: The proposed budget and multi-year forecast will include resources to ensure the Board of Commissioners can fulfill their policy-making responsibilities.

Conclusion: This Executive Limitation was followed with no known exceptions.

Summary Data: The proposed budget and multi-year forecast prepared for the October 21, 2025 public hearing included resources specific to the Board of Commissioners and was prepared in conjunction with the Clerk of the Board based on Board input.

Executive Limitation 4: *Accordingly, the CEO/General Manager shall not allow financial planning/budgeting which allows Electric System year-end debt service coverage to fall below 1.75.*

Interpretation: The proposed budget and multi-year forecast will reflect debt service coverage for each year at 1.75 or higher.

Conclusion: This Executive Limitation was followed with no known exceptions.

Summary Data: The proposed budget and multi-year forecast prepared for the October 21, 2025 public hearing reflected debt service coverage levels above 1.75.

Executive Limitation 5: *Accordingly, the CEO/General Manager shall not allow financial planning/budgeting which finances greater than forty percent (40%) of non-generation or*

energy storage Electric System capital assets within a fifteen-year term, including a ten-year historic and 5-year planning period.

Interpretation: The proposed budget and multi-year forecast will be prepared assuming bond proceeds for the fifteen-year period (including the multi-year forecast) do not exceed 40% of capital expenditures during the planning period.

Conclusion: This Executive Limitation was followed with no known exceptions.

Summary Data: The proposed budget and multi-year forecast prepared for the October 21, 2025 public hearing reflected bond proceeds that were below 40% of the anticipated capital expenditures during the planning period.

Executive Limitation 6: Accordingly, *the General Manager shall not allow financial planning/budgeting which plans for rate increases in excess of three percent (3%) in any year, or compound increases in excess of ten percent (10%) over any consecutive five-year period exclusive of rate increases that are forecasted by Bonneville Power Administration (BPA) for electricity and the City of Everett for water purchases.*

Interpretation: The proposed budget and multi-year forecast will not plan for general rate increases greater than 3% in any year or cumulative general rate increases greater than 10% compounded over a five-year period.

Conclusion: This Executive Limitation was met for the Electric System. The Executive Limitation was not met for the Water System. In order to address significant inflation and other cost pressures in the five-year forecast, the District has suggested rate increases higher than the policy for Water.

Summary Data: The Electric System proposed budget and multi-year forecast prepared for the October 21, 2025 public hearing reflected a proposed general rate increase of 2.50% in 2026, 2.50% in 2027, 2.00% in 2028 and 0% 2029-2030. The Water proposed budget and multi-year forecast prepared for the November 4, 2025 public hearing reflected a general rate increase of 5.75% in 2026, 4.80% in 2027, 4.75% in 2028, 4.50% in 2029 and 4.00% in 2030.

Signature: Jeff Bishop
Email: jmbishop@snopud.com

Signature: John Haarlow
Email: jahaarlow@snopud.com

BUSINESS OF THE COMMISSION

Meeting Date: December 2, 2025 **Agenda Item:** 8B

TITLE

Consideration of a Resolution Authorizing the Chief Operating and Legal Officer of Public Utility District No. 1 of Snohomish County to Execute an Aquatic Lands Lease With the Washington State Department of Natural Resources Concerning the Hat Island Submarine Cable Project

SUBMITTED FOR: Items for Individual Consideration

Distribution & Engineering	Eric Schneider	8624
Department	*Contact*	*Extension*

Date of Previous Briefing: _____

Estimated Expenditure: _____ Presentation Planned ☐

ACTION REQUIRED:

☐ Decision Preparation
- ☐ Policy Discussion
- ☐ Policy Decision
- ☒ Statutory

☐ Incidental (Information)

☐ Monitoring Report

SUMMARY STATEMENT:

Identify the relevant Board policies and impacts:

Governance Process, Board Job Description: GP-3(4)(F)(1) a non-delegable, statutorily assigned Board duty to authorize acquisition … of certain properties and payment therefor.

The District is constructing the Hat Island Submarine Cable Project (the "Project") to replace an aging submarine power distribution cable that provides electrical service to the residential and business customers on Hat Island. The Project involves the installation of a new 32,000 linear-foot submarine three-phase power cable in Possession Sound between the Port of Everett and Hat Island. The District needs to obtain an aquatic lands lease from the Washington State Department of Natural Resources (DNR) for authorization to place the conduit and submarine cable on and over state-owned aquatic lands. DNR and the District staff negotiated an aquatic lands lease subject to the approval of the District Board of Commissioners.

District Staff recommend that the District Board of Commissioners adopt the resolution authorizing execution of the aquatic lands lease with DNR.

List Attachments:

Resolution
Exhibit A

RESOLUTION NO. ____

A RESOLUTION Authorizing the Chief Operating and Legal Officer of Public Utility District No. 1 of Snohomish County to Execute an Aquatic Lands Lease With the Washington State Department of Natural Resources Concerning the Hat Island Submarine Cable Project

WHEREAS, Public Utility District No. 1 of Snohomish County (the "District") is constructing the Hat Island Submarine Cable Project (the "Project") to replace an aging submarine power distribution cable that provides electrical service to the residential and business customers on Hat Island; and

WHEREAS, the Project involves the installation of a new 32,000 linear-foot submarine three-phase power cable in Possession Sound between the Port of Everett and Hat Island; and

WHEREAS, the District is proposing to use horizontal directional drilling on both landings to avoid impacts to eelgrass and nearshore habitat; and

WHEREAS, the submarine cable will emerge underwater between the horizontal directional drilled conduit and be laid directly on the seafloor; and

WHEREAS, the District needs to obtain an aquatic lands lease from the Washington State Department of Natural Resources (DNR) for authorization to place the conduit and submarine cable on and over state-owned aquatic lands; and

WHEREAS, representatives of DNR and the District have negotiated an Aquatic Lands Lease subject to the approval of the District Board of Commissioners; and

WHEREAS, the lease is for a period of thirty (30) years beginning on November 1, 2025, and ending on October 31, 2055, at which time the District may apply for a new easement with the DNR; and

WHEREAS, RCW 79.110.230 provides that the use of state-owned aquatic lands for public utility lines owned by a governmental entity are exempt from annual charges and subject only to recovery of administrative costs incurred in processing and approving the application; and

WHEREAS, under the aquatic lands lease the District is responsible for payment of an administrative fee of seven thousand eight hundred dollars ($7,800); and

WHEREAS, District staff recommend that the Board of Commissioners authorize execution of the Aquatic Lands Lease with DNR, a copy of which is attached as Exhibit "A", and the Board of Commissioners believes that such execution is in the best interests of the District and its ratepayers.

NOW, THEREFORE, BE IT RESOLVED by the Commission of Public Utility District No. 1 of Snohomish County, Washington, that the Chief Operating and Legal Officer, or his designee, is authorized to:

1. Execute the Aquatic Lands Lease with the Washington State Department of Natural Resources, in substantially the form attached as Exhibit "A" and incorporated by this reference; and
2. Execute any other documents and take any other actions necessary to support and execute the Aquatic Lands Lease with the Washington State Department of Natural Resources.

PASSED AND APPROVED this 2nd day of December, 2025.

_____
President

_____
Vice-President

_____
Secretary

When recorded, return to:
Public Utility District No.1 of Snohomish County
PO Box 1107
Everett, WA 98206

DAVE UPTHEGROVE
COMMISSIONER OF PUBLIC LANDS

AQUATIC LANDS EASEMENT

Easement No. 51-101635

Grantor: Washington State Department of Natural Resources
Grantee(s): Snohomish County Public Utility District No.1
Abbreviated Legal Description: NE ¼ NW ¼ Section 8 and NE¼ SE¼, Township 29 North, Range East, W.M.
Complete Legal Description on Page 32 and 33
Assessor's Property Tax Parcel or Account Number: Not Applicable
Assessor's Property Tax Parcel or Account Number for Upland parcel used in conjunction with this Easement: Not Applicable

THIS EASEMENT is made by and between the STATE OF WASHINGTON, acting through the Department of Natural Resources ("State"), and PUBLIC UTILITY DISTRICT NO. 1 OF SNOHOMISH COUNTY ("Grantee"). State has authority to enter into this Easement under Chapter 43.12 RCW, Chapter 43.30 RCW, and Title 79 of the Revised Code of Washington (RCW).

THEREFORE, the Parties agree as follows:

SECTION 1 GRANT OF EASEMENT

1.1 Easement Defined.

(a) State grants and conveys to Grantee a nonexclusive in gross easement, subject to the terms and conditions of this agreement, over, upon, and under bedlands and Harbor Area legally described in Exhibit A"Easement Property". In this agreement, the term "Easement" means this agreement and the rights granted.

(b) This Easement is subject to all valid interests of third parties noted in the records of Snohomish County, or on file in the Office of the Commissioner of Public Lands, Olympia, Washington; rights of the public under the Public Trust Doctrine or federal navigation servitude; and treaty rights of Indian Tribes.

(c) This Easement does not include any right to harvest, collect or damage any natural resources, including, but not limited to, aquatic life or living plants; any water rights; any mineral rights; or any right to excavate or withdraw sand, gravel, or other valuable materials except to the extent expressly permitted in Exhibit B.

(d) This Easement is not exclusive. State may enter and use the Easement Property for any purpose or permit others to enter and use the Easement Property for any purpose so long as such use does not unreasonably interfere with the rights granted herein.

1.2 Survey and Easement Property Descriptions.

(a) Grantee's obligation to provide a true and accurate description of the Easement Property, and the location of the Improvements to be constructed is a material term of this Easement. Grantee warrants that the legal description provided in Exhibit A includes a true and accurate description of the Easement Property, and the location of the Improvements to be constructed.

(b) Unless State has given Grantee written authorization to use such lands, Grantee's use of any state-owned aquatic lands outside the Easement Property boundaries is a material breach of this Easement and State may seek remedies under Section 14 of this Easement in addition to any other remedies afforded by law or equity or otherwise.

(c) Grantee shall submit an updated record of survey for State's acceptance within Three hundred Sixty Five (365) days of the Commencement Date. Upon State's written acceptance of the updated record of survey, the updated record of survey shall supersede the record of survey referenced in Exhibit A. The specific location of the Easement Property shall be deemed to be as shown on the updated record of survey.

(d) Grantee's submission of the updated record of survey shall constitute a warranty that the updated record of survey is a true and accurate description of the Easement Property and the as-built location of all Improvements on the Easement Property. Grantee's obligation to provide a true and accurate description of the

Easement Property and the as-built location of Improvements on the Easement Property in the updated record of survey is a material term of this Easement.

(e) At Grantee's expense, and no later than thirty (30) days after receiving State's written acceptance of the updated record of survey, Grantee shall record the updated record of survey in the County in which the Property is located. Grantee shall provide State with recording information, including the date of recordation and the file number, within fifteen (15) days after recording the updated record of survey.

1.3 Condition of Easement Property. State makes no representation regarding the condition of the Easement Property, Improvements located on the Easement Property, the suitability of the Easement Property for Grantee's Permitted Use, compliance with governmental laws and regulations, availability of utility rights, access to the Easement Property, or the existence of hazardous substances on the Easement Property.

SECTION 2 USE

2.1 Permitted Use. This Easement is granted for the purpose of and is limited to:

One (1) submerged electrical cable (the "Permitted Use").

Exhibit B includes additional details about the Permitted Use, the Easement Property, and the Improvements. Exhibit B also includes additional obligations on Grantee. The Permitted Use is subject to the restrictions and additional obligations set forth in this Easement. The Permitted Use of this Easement shall not be changed or modified without the written consent of State, which shall be at State's sole discretion.

2.2 Restrictions on Permitted Use and Operations.

(a) Grantee shall not cause or permit:

(1) Damage to land or natural resources on the Easement Property or adjacent state-owned aquatic lands, regardless of whether the damages are a direct or indirect result of the Permitted Use

(2) Waste on the Easement Property or adjacent state-owned aquatic lands; or

(3) Deposit of material or filling activity on the Easement Property or adjacent state-owned aquatic lands, unless approved by State in writing and except to the extent expressly permitted in Exhibit. This prohibition includes, but is not limited to, any deposit of fill, rock, earth, ballast, wood waste, hydrocarbons, refuse, garbage, waste matter (including, but not limited to, chemical, biological, or toxic wastes), pollutants, or other matter.

(b) Nothing in this Easement shall be interpreted as an authorization to dredge the Easement Property.

(c) Grantee shall immediately notify State if Grantee breaches any of the terms and conditions of this Easement.

(d) State's failure to notify Grantee of Grantee's failure to comply with all or any of the restrictions set out in this Paragraph 2.2 does not constitute a waiver of any remedies available to State.

(e) Grantee's compliance with the restrictions in this Paragraph 2.2 does not limit Grantee's liability under any other provision of this Easement or the law.

2.3 Conformance with Laws. Grantee shall keep current and comply with all conditions and terms of any permits, licenses, certificates, regulations, ordinances, statutes, and other government rules and regulations regarding Grantee's use of the Easement Property.

2.4 Liens and Encumbrances. Unless expressly authorized by State in writing, Grantee shall keep the Easement Property free and clear of any liens and encumbrances arising out of or relating to the Permitted Use or Grantee's use of the Easement Property.

2.5 Interference with Other Uses.

(a) Grantee shall exercise Grantee's rights under this Easement in a manner that minimizes or avoids interference with the rights of State, the public, or others with valid rights to use or occupy the Easement Property or surrounding lands and water.

(b) To the fullest extent reasonably possible, Grantee shall place and construct Improvements in a manner that allows unobstructed movement in and on the waters above and around the Easement Property.

(c) Except in an emergency, Grantee shall provide State with written notice regarding the start of construction or other Significant Activity on the Easement Property at least sixty (60) days in advance ("Notice of Significant Activity"). "Significant Activity" means any activity that may affect the use or enjoyment of the Easement Property or adjacent state-owned aquatic lands by the State of Washington, public, or others with valid rights to use or occupy the Easement Property or adjacent state-owned aquatic lands.

(d) Grantee shall mark the location of any hazards associated with the Permitted Use and any hazards associated with the Improvements in a manner that ensures reasonable notice to the public, including, but not limited to, boaters, kayakers, swimmers, and divers. Grantee shall mark the location and limits of the Improvements located on the Easement Property. The signs and notices shall identify the type of installation (e.g., a pipe or cable), identify Grantee as the entity responsible for the Permitted Use and its maintenance, and be posted in location that gives reasonable notice to the public. When required by applicable law or regulation, Grantee shall facilitate amendment of official navigational charts to indicate existence and location of submerged Improvements.

SECTION 3 TERM

3.1 Term Defined. The term of this Easement is Thirty (30) years, beginning on the 1st day of November, 2025 (the "Commencement Date"), and ending on the 31st day of October, 2055 (the "Termination Date"), unless terminated sooner under the terms of this Easement (the "Term"). Whenever the phrase "termination of this Easement" or "termination of the Easement" is used in this Easement, it shall refer to the ending, termination, cancellation, or expiration of the Easement.

3.2 Renewal of Easement and/or Application for New Easement.
This Easement does not provide a right of renewal. Grantee may apply for a new Easement, which State has discretion to grant. Grantee must apply for a new Easement at least one (1) year prior to Termination Date.

3.3 End of Term.

(a) Removal of Improvements: Prior to the termination of this Easement, Grantee shall remove Improvements in accordance with Section 7.

(b) Restoration of the Easement Property:

(1) Prior to the termination of this Easement, Grantee shall restore the Easement Property to its condition before the installation of any Improvements on the Easement Property.

(2) Restoration of the Easement Property is to be done at Grantee's expense and to the satisfaction of State. Restoration of the Easement Property is considered to be Work, as described in Section 7 of the Easement. Grantee's plans for restoring the Easement Property shall be submitted to State for prior approval in accordance with Section 7 of this Easement.

(3) If Grantee fails to restore the condition of the Easement Property as required by this Paragraph, State may take steps reasonably necessary to remedy Grantee's failure. Upon demand by State, Grantee shall pay all costs of State's remedy, lost revenue resulting from the condition of the Easement Property, and administrative costs associated with State's remedy.

(c) Vacation of Property: Upon the termination of this Easement, Grantee shall cease all operations on and use of the Easement Property.

SECTION 4 FEES

4.1 Fee. For the Term, Grantee shall pay to State an administrative fee calculated in accordance with RCW 79.110.240 of Seven Thousand Eight Hundred Dollars ($7,800), which is due and payable on or before the Commencement Date. Any payment not paid by State's close of business on the date due is past due.

4.2 Payment Place. Grantee shall make payment to Financial Management Division, 1111 Washington St SE, PO Box 47041, Olympia, WA 98504-7041.

SECTION 5 OTHER EXPENSES

5.1 Utilities. Grantee shall pay all fees charged for utilities required or needed by the Permitted Use.

5.2 Taxes and Assessments. Grantee shall pay all taxes, assessments, and other governmental charges applicable or attributable to the Easement, the Grantee-Owned Improvements, or the Permitted Use.

5.3 Proof of Payment. If required by State, Grantee shall furnish to State receipts or other appropriate evidence establishing the payment of amounts this Easement requires Grantee to pay.

SECTION 6 LATE PAYMENTS AND OTHER CHARGES

6.1 Failure to Pay. Failure to pay any fees or other expenses due under this Easement is a breach by Grantee. State may seek remedies in Section 14 as well as late charges and interest as provided in this Section 6. In addition, if Grantee fails to pay any amounts due to third parties under this Easement, State may pay the amount due, and recover its cost in accordance with this Section 6.

6.2 Late Charge. If State does not receive any payment within ten (10) days of the date due, Grantee shall pay to State a late charge equal to four percent (4%) of the unpaid amount or Fifty Dollars ($50), whichever is greater, to defray the overhead expenses of State incident to the delay.

6.3 Interest Penalty for Past Due Fees and Other Sums Owed.

(a) Grantee shall pay interest on the past due fees at the rate of one percent (1%) per month until paid, in addition to paying the late charges determined under Paragraph 6.2. Fees not paid by the close of business on the due date will begin accruing interest the day after the due date.

(b) If State pays or advances any amounts for or on behalf of Grantee, Grantee shall reimburse State for the amount paid or advanced and shall pay interest on that amount at the rate of one percent (1%) per month from the date State notifies Grantee of the payment or advance. This includes, but is not limited to State's payment of taxes, assessments, insurance premiums, costs of removal and disposal of unauthorized materials, costs of removal and disposal of Improvements under any provision of this Easement, or other amounts not paid when due.

6.4 Referral to Collection Agency and Collection Agency Fees. If State does not receive full payment within thirty (30) days of the due date, State may refer the unpaid amount to a collection agency as provided by RCW 19.16.500 or other applicable law. Upon referral, Grantee shall pay collection agency fees in addition to the unpaid amount.

6.5 No Accord and Satisfaction. If Grantee pays, or State otherwise receives, an amount less than the full amount then due, State may apply such payment as it elects. State may accept payment in any amount without prejudice to State's right to recover the balance or pursue any other right or remedy. No endorsement or statement on any check, any payment, or any letter accompanying any check or payment constitutes accord and satisfaction.

SECTION 7 IMPROVEMENTS, PERSONAL PROPERTY, AND WORK

7.1 Improvements and Personal Property Defined.

(a) "Improvements," consistent with RCW 79.105 through 79.140, are additions within, upon, or attached to the Easement Property. Improvements include, but are not limited to, fill, structures and fixtures.

(b) "Personal Property" means items that can be removed from the Easement Property without (1) injury to the Easement Property, adjacent state-owned lands or Improvements or (2) diminishing the value or utility of the Easement Property, adjacent state-owned lands or Improvements.

(c) "State-Owned Improvements" are Improvements made or owned by the State of Washington. State-Owned Improvements include any construction, alteration, or addition to State-Owned Improvements made by Grantee.

(d) "Grantee-Owned Improvements" are (1) Improvements owned by Grantee that are existing on the Easement Property on the Commencement Date or (2) Improvements made by Grantee with State's consent.

(e) "Unauthorized Improvements" are Improvements made on the Easement Property during the Term without State's prior consent or Improvements made by Grantee that do not conform with plans submitted to and approved by State.

(f) "Improvements Owned by Others" are Improvements made by others with a right to occupy or use the Easement Property or adjacent state-owned lands.

7.2 Existing Improvements. On the Commencement Date there are no Improvements located on the Easement Property.

7.3 Construction, Major Repair, Modification, and Other Work.

(a) This Paragraph 7.3 governs construction, alteration, replacement, major repair, modification, and removal of Improvements (collectively "Work").

(b) Except in an emergency, Grantee shall not conduct any Work without State's prior written consent. Grantee shall obtain State's prior written consent as follows:

(1) Grantee shall submit to State plans and specifications describing the proposed Work at least sixty (60) days before submitting permit applications to regulatory authorities, unless Grantee and State otherwise agree to coordinate permit applications. At a minimum, or if no permits are necessary, Grantee shall submit plans and specifications to State at least ninety (90) days before commencement of Work.

(2) State may deny consent if State determines that denial is in the best interests of the State of Washington or if the proposed Work does not comply with Paragraph 7.4. State may impose additional conditions intended to protect and preserve the Easement Property or adjacent state-owned aquatic lands.

(3) State will not approve plans to construct new Improvements or expand existing Improvements in or over habitats designated by State as important habitat, including, but not limited to: native aquatic vegetation, commercial geoduck tracts, forage fish spawning areas, and salmon critical habitat. Grantee shall confirm location of important habitat on Property, if any, with State before submitting plans and specifications in accordance with Paragraph 7.3.

(c) Grantee shall immediately notify State of emergency Work. Upon State's request, Grantee shall provide State with as-built plans and specifications of emergency Work.

(d) Grantee shall not commence Work until Grantee or Grantee's contractor has:

(1) Obtained a performance and payment bond in an amount equal to one hundred percent of the estimated cost of construction. Grantee or Grantee's contractor shall maintain the performance and payment bond until the costs of the Work, including all laborers and material persons, are paid in full.

(2) Obtained all required permits.

(3) Provided Notice of Significant Activity in accordance with Paragraph 2.5(c).

(e) Grantee shall preserve and protect Improvements Owned by Others, if any.

(f) Grantee shall preserve all legal land subdivision survey markers and witness objects ("Markers"). If disturbance of a Marker will be a necessary consequence of Grantee's construction, Grantee shall reference and/or replace the Marker in accordance with all applicable laws and regulations current at the time, including, but not limited to Chapter 58.24 RCW. At Grantee's expense, Grantee shall retain a registered professional engineer or licensed land surveyor to reestablish destroyed or disturbed Markers in accordance with United States General Land Office standards.

(g) Before completing Work, Grantee shall remove all debris and restore the Easement Property, as nearly as possible, to its natural condition before the Work began. If Work is intended for removal of Improvements at End of Term, Grantee

shall restore the Easement Property in accordance with Paragraph 3.3, End of Term.

(h) Upon completing Work, Grantee shall promptly provide State with as-built plans and specifications. State may also require Grantee to obtain an updated record of survey showing the Easement Property boundaries and the as-built location of all Improvements on the Easement Property.

(i) State shall not charge additional fees for authorized Improvements installed by Grantee on the Easement Property during this Term, but State may charge additional fees for such Improvements if and when the Grantee or successor obtains a subsequent use authorization for the Easement Property and State has waived the requirement for removal of Improvements as provided in Paragraph 7.5.

7.4 Standards for Work.

(a) Applicability of Standards for Work.

(1) The standards for Work in Paragraph 7.4(b) apply to Work commenced in the five-year period following the Commencement Date. Work commences when State approves plans and specifications.

(2) If Grantee commences Work five years or more after the Commencement Date, Grantee shall comply with State's current standards for Work.

(3) If Grantee commences Work five years or more after the Commencement Date, Grantee shall ascertain State's current standards for Work as follows:

(i) Before submitting plans and specifications for State's approval as required by Paragraph 7.3 of the Easement, Grantee shall request State to provide Grantee with State's current standards for Work on state-owned aquatic lands.

(ii) Within thirty (30) days of receiving Grantee's request, State shall provide Grantee with State's current standards for Work, which will be effective for the purpose of State's approval of Grantee's proposed Work, provided Grantee submits plans and specifications for State's approval within two (2) years of Grantee's request for standards.

(iii) If State does not timely provide State's current standards for Work upon Grantee's request, the standards for Work under Paragraph 7.4(b) apply to Grantee's Work, provided Grantee submits plans and specifications as required by Paragraph 7.3 within two (2) years of Grantee's request for State's current standards for Work.

(iv) If Grantee fails to (1) make a request for State's current standards for Work or (2) timely submit plans and specifications to State after receiving State's current standards for Work, Grantee, at Grantee's sole expense, shall make changes in plans or Work

necessary to conform to State's current standards for Work upon State's demand.

(b) The following standards for Work apply to Work commenced in the five-year period following the Commencement Date.

(1) Grantee shall only conduct in-water Work during time periods authorized for such work under WAC 220-660-330, Authorized Work Times in Saltwater Areas, or as otherwise directed by the Washington Department of Fish and Wildlife (WDFW).

7.5 Grantee-Owned Improvements at End of Easement.

(a) Disposition.

(1) Grantee shall remove Grantee-Owned Improvements in accordance with Paragraph 7.3 upon the termination of the Easement unless State waives the requirement for removal.

(2) Grantee-Owned Improvements remaining on the Easement Property on the termination of the Easement shall become State-Owned Improvements without payment by State, unless State elects otherwise. State may refuse or waive ownership.

(3) If Grantee-Owned Improvements remain on the Easement Property after the termination of the Easement without State's consent, State may remove all Improvements and Grantee shall pay State's costs of removal and disposal.

(b) Conditions Under Which State May Waive Removal of Grantee-Owned Improvements.

(1) State may waive removal of any Grantee-Owned Improvements whenever State determines that it is in the best interests of the State of Washington.

(2) If Grantee enters into a new Easement, State may waive requirement to remove Grantee-Owned Improvements. State also may consent to Grantee's continued ownership of Grantee-Owned Improvements.

(3) State may waive requirement to remove Grantee-Owned Improvements upon consideration of a timely request from Grantee, as follows:

(i) Grantee shall submit its request to leave Grantee-Owned Improvements to State at least one (1) year before the Termination Date.

(ii) State, within ninety (90) days of receiving Grantee's request, will notify Grantee whether State consents to any Grantee-Owned Improvements remaining. State has no obligation to grant consent.

(iii) State's failure to respond to Grantee's request to leave Improvements within ninety (90) days is a denial of the request.

(c) Grantee's Obligations if State Waives Removal.

(1) Grantee shall not remove a Grantee-Owned Improvement if State waives the requirement for removal of that Grantee-Owned Improvement.

(2) Grantee shall maintain such Grantee-Owned Improvements in accordance with this Easement until the termination of this Easement. State may

require Grantee to take appropriate steps to decommission the structure. Grantee is liable to State for cost of repair if Grantee causes or allows damage to Grantee-Owned Improvements State has designated to remain.

(3) State may condition its waiver of removal on Grantee entering into a new Easement for the Grantee-Owned Improvements.

7.6 Unauthorized Improvements.

(a) Unauthorized Improvements belong to State, unless State elects otherwise.

(b) The placement of Unauthorized Improvements on the Easement Property is a breach of this Easement and State may require removal of any or all Unauthorized Improvements. If State requires removal of Unauthorized Improvements and if Grantee fails to remove the Unauthorized Improvements, State may remove the Unauthorized Improvements and Grantee shall pay for the cost of removal and disposal.

(c) In addition to requiring removal of Unauthorized Improvements, State may charge Grantee a use fee that is sixty percent (60%) higher than the full market value of the use of the land for the Unauthorized Improvements from the time of installation or construction until the time the Unauthorized Improvements are removed.

(d) If State consents to Unauthorized Improvements remaining on the Easement Property, upon State's consent, the Unauthorized Improvements will be treated as Grantee-Owned Improvements and the removal and ownership of such Improvements shall be governed by Paragraph 7.5. If State consents to the Unauthorized Improvements remaining on the Easement Property, State may charge a use fee that is sixty percent (60%) higher than the full market value of the use of the land for the Unauthorized Improvements from the time of installation or construction until State consents.

7.7 Personal Property.

(a) Grantee retains ownership of Personal Property unless Grantee and State agree otherwise in writing.

(b) Grantee shall remove Personal Property from the Easement Property by the termination of the Easement. Grantee is liable for damage to the Easement Property and to any Improvements that may result from removal of Personal Property.

(c) State may remove, sell, or dispose of all Personal Property left on the Easement Property after the termination of the Easement.

(1) If State conducts a sale of Personal Property, State shall first apply **proceeds to State's costs of removing the Personal Property, State's costs** in conducting the sale, and any other payment due from the Grantee to State. State shall pay the remainder, if any, to the Grantee. Grantee shall be liable for any costs of removing the Personal Property and conducting the sale that exceed the proceeds received by State.

(2) If State disposes of Personal Property, Grantee shall pay for the cost of removal and disposal.

SECTION 8 ENVIRONMENTAL LIABILITY/RISK ALLOCATION

8.1 Definitions.

(a) "Hazardous Substance" means any substance that now or in the future becomes regulated or defined under any federal, state, or local statute, ordinance, rule, regulation, or other law relating to human health, environmental protection, contamination, pollution, or cleanup.

(b) "Release or threatened release of Hazardous Substance" means a release or threatened release as defined under any law described in Paragraph 8.1(a).

(c) "Utmost care" means such a degree of care as would be exercised by a very careful, prudent, and competent person under the same or similar circumstances; the utmost care required under RCW 70A.305.040(3)(a)(iii) of the Washington State Model Toxics Control Act.

(d) "Grantee and affiliates" when used in this Section 8 means Grantee or Grantee's subgrantees, contractors, agents, employees, guests, invitees, licensees, affiliates, or any person on the Easement Property with the Grantee's permission.

(e) "Liabilities" as used in this Section 8 means any claims, demands, proceedings, lawsuits, damages, costs, expenses, fees (including attorneys' fees and disbursements), penalties, or judgments.

8.2 General Conditions.

(a) Grantee's obligations under this Section 8 extend to the area in, on, under, or above:

(1) The Easement Property and

(2) Adjacent state-owned aquatic lands if affected by a release of Hazardous Substances that occurs as a result of the Permitted Use.

(b) Standard of Care.

(1) Grantee shall exercise the utmost care with respect to Hazardous Substances.

(2) As relates to the Permitted Use, Grantee shall exercise utmost care for the foreseeable acts or omissions of third parties with respect to Hazardous Substances, and the foreseeable consequences of those acts or omissions, to the extent required to establish a viable, third-party defense under the law.

8.3 Current Conditions and Duty to Investigate.

(a) State makes no representation about the condition of the Easement Property or adjacent state-owned aquatic lands. Hazardous Substances may exist in, on, under, or above the Easement Property or adjacent state-owned aquatic lands

(b) This Easement does not impose a duty on State to conduct investigations or supply information to Grantee about Hazardous Substances.

(c) Grantee is responsible for conducting all appropriate inquiry and gathering sufficient information concerning the Easement Property and the existence, scope, and location of Hazardous Substances on or near the Easement Property necessary for Grantee to meet Grantee's obligations under this Easement and utilize the Easement Property for the Permitted Use.

8.4 Use of Hazardous Substances.

(a) Grantee and affiliates shall not use, store, generate, process, transport, handle, release, or dispose of Hazardous Substances, except in accordance with all applicable laws.

(b) Grantee shall not undertake, or allow others to undertake by Grantee's permission, acquiescence, or failure to act, activities that result in a release or threatened release of Hazardous Substances.

(c) If use of Hazardous Substances related to the Permitted Use or Grantee's use of the Property results in a violation of law:

(1) Grantee shall submit to State any plans for remedying the violation, and

(2) Grantee shall implement any measures to restore the Easement Property or natural resources that State may require in addition to remedial measures required by regulatory authorities.

8.5 Management of Contamination.

(a) Grantee and affiliates shall not undertake activities that:

(1) Damage or interfere with the operation of remedial or restoration activities, if any;

(2) Result in human or environmental exposure to contaminated sediments, if any;

(3) Result in the mechanical or chemical disturbance of on-site habitat mitigation, if any.

(b) If requested, Grantee shall allow reasonable access to:

(1) Employees and authorized agents of the United States Environmental Protection Agency (EPA), the Washington State Department of Ecology, health department, or other similar environmental agencies; and

(2) Potentially liable or responsible parties who are the subject of an order or consent decree that requires access to the Easement Property. Grantee may negotiate an access agreement with such parties, but Grantee may not unreasonably withhold such agreement.

8.6 Notification and Reporting.

(a) Grantee shall immediately notify State if Grantee becomes aware of any of the following:

(1) A release or threatened release of Hazardous Substances;

(2) Any new discovery of or new information about a problem or liability related to, or derived from, the presence of Hazardous Substances;
(3) Any lien or action arising from Hazardous Substances;
(4) Any actual or alleged violation of any federal, state, or local statute, ordinance, rule, regulation, or other law pertaining to Hazardous Substances;
(5) Any notification from the EPA or the Washington State Department of Ecology that remediation or removal of Hazardous Substances is or may be required at the Easement Property.

(b) Grantee's duty to report under Paragraph 8.6(a) extends to lands described in Paragraph 8.2(a), and to any other property used by Grantee in conjunction with the Easement Property if a release of Hazardous Substances on the other property could affect the Easement Property.

(c) Grantee shall provide State with copies of all documents Grantee submits to any federal, state, or local authorities concerning environmental impacts or proposals relative to the Easement Property. Documents subject to this requirement include, but are not limited to, applications, reports, studies, or audits for National Pollutant Discharge Elimination System permits (NPDES); United States Army Corps of Engineers permits; State Hydraulic Project Approvals (HPA); State Water Quality Certifications; Substantial Shoreline Development permits; and any reporting necessary for the existence, location, and storage of Hazardous Substances on the Easement Property.

8.7 Indemnification.

(a) Grantee shall fully indemnify, defend, and hold harmless State from and against any Liabilities that arise out of, or relate to:
(1) The use, storage, generation, processing, transportation, handling, or disposal of any Hazardous Substance by Grantee and affiliates occurring whenever Grantee uses or has used the Easement Property;
(2) The release or threatened release of any Hazardous Substance resulting from any act or omission of Grantee and affiliates occurring whenever Grantee uses or has used the Easement Property.

(b) Grantee shall fully indemnify, defend, and hold harmless State for any Liabilities that arise out of or relate to Grantee's breach of obligations under Paragraph 8.5.

(c) If Grantee fails to exercise care as described in Paragraph 8.2(b)(2), Grantee shall fully indemnify, defend, and hold harmless State from and against Liabilities arising from the acts or omissions of third parties in relation to the release or threatened release of Hazardous Substances.

8.8 Reservation of Rights.

(a) For Liabilities not covered by the indemnification provisions of Paragraph 8.7, the Parties expressly reserve and do not waive any rights, claims, immunities, causes

of action, or defenses relating to Hazardous Substances that either Party may have against the other under law.

(b) The Parties expressly reserve all such rights, claims, immunities, and defenses that either Party may have against third parties. Nothing in this Section 8 benefits or creates rights for third parties.

(c) The allocations of risks, Liabilities, and responsibilities set forth in this Section 8 do not release either Party from or affect the liability of either Party for Hazardous Substances claims or actions by regulatory agencies.

8.9 Cleanup.

(a) If Grantee's act, omission, or breach of obligation under Paragraph 8.4 results in a release of Hazardous Substances that exceeds the threshold limits of any applicable regulatory standards, Grantee shall, at Grantee's sole expense, promptly take all actions necessary or advisable to clean up the Hazardous Substances in accordance with applicable law.

(b) If a cleanup is eligible for the Washington State Department of Ecology's Voluntary Cleanup Program, Grantee may undertake a cleanup of the Easement Property pursuant to the Washington State Department of Ecology's Voluntary Cleanup Program, provided that Grantee cooperates with the Department of Natural Resources in development of cleanup plans. Grantee shall not proceed with Voluntary Cleanup without the Department of Natural Resources' approval of final plans. Nothing in the operation of this provision is an agreement by the Department of Natural Resources that the Voluntary Cleanup complies with any laws or with the provisions of this Easement. Grantee's completion of a Voluntary Cleanup is <u>not</u> a release from or waiver of any obligation for Hazardous Substances under this Easement.

8.10 Sampling by State, Reimbursement, and Split Samples.

(a) State may conduct sampling, tests, audits, surveys, or investigations ("Tests") of the Easement Property at any time to determine the existence, scope, or effects of Hazardous Substances.

(b) If such Tests, along with any other information, demonstrate a breach of Grantee's obligations regarding Hazardous Substances under this Easement, Grantee shall promptly reimburse State for all costs associated with such Tests, provided State gave Grantee thirty (30) days' advance notice in nonemergencies, and reasonably practical notice in emergencies.

(c) In nonemergencies, Grantee is entitled to obtain split samples of Test samples, provided Grantee gives State written notice requesting split samples at least ten (10) days before State conducts Tests. Upon demand, Grantee shall promptly reimburse State for additional cost, if any, of split samples.

(d) If either Party conducts Tests on the Easement Property, the conducting Party shall provide the other Party with validated final data and quality assurance/quality control/chain of custody information about the Tests within

sixty (60) days of a written request by the other Party, unless Tests are part of a submittal under Paragraph 8.6(c) in which case Grantee shall submit data and information to State without written request by State. Neither party is obligated to provide any analytical summaries or the work product of experts.

SECTION 9 NATURE OF ESTATE AND ASSIGNMENT

This Easement shall be in gross for the sole benefit of Grantee's use associated with the Permitted Use. This Easement shall not run with the land. This Easement is indivisible. Grantee shall not sell, convey, mortgage, assign, pledge, grant franchises for, or otherwise transfer or encumber any part of Grantee's interest in this Easement or any part of Grantee's interest in the Easement Property without State's prior written consent, which shall be at State's sole discretion. State reserves the right to reasonably change the terms and conditions of this Easement upon State's consent to requests made under this Section 9.

SECTION 10 INDEMNITY, INSURANCE, FINANCIAL SECURITY

10.1 Indemnity.

(a) Grantee shall indemnify, defend, and hold harmless State, its employees, officials, officers, and agents from any Claim arising out of the Permitted Use, any Claim arising out of activities related to the Permitted Use, and any Claim arising out of the use of the Easement Property by Grantee, its contractors, agents, invitees, guests, employees, affiliates, licensees, or permittees, to the fullest extent permitted by law and subject to the limitations provided below.

(b) "Claim" as used in this Paragraph 10.1 means any financial loss, claim, suit, action, damages, expenses, costs, fees (including attorneys' fees), fines, penalties, or judgments attributable to: bodily injury; sickness; disease; death; damages to tangible property, including, but not limited to, land, aquatic life, and other natural resources. "Damages to tangible property" includes, but is not limited to, physical injury to tangible property, diminution in value of tangible property, damages resulting from loss of use of tangible property, and loss or diminution of natural resource values.

(c) State shall not require Grantee to indemnify, defend, and hold harmless State, its employees, officials, officers, and agents for a Claim caused solely by or resulting solely from the negligence or willful act of State or State's employees, officials, officers, or agents.

(d) Grantee specifically and expressly waives any immunity that may be granted under the Washington State Industrial Insurance Act, Title 51 RCW in connection with its obligation to indemnify, defend, and hold harmless State and its employees, officials, officers, and agents. Further, Grantee's obligation under this Easement to indemnify, defend, and hold harmless State and its employees, officials, officers, and agents shall not be limited in any way by any limitation on

amount or type of damages, compensation, or benefits payable to or for any third party under the workers' compensation acts.

(e) Only to the extent RCW 4.24.115 applies and requires such a limitation, if a Claim, is caused by or results from the concurrent negligence of (a) State or State's employees, officials, officers, or agents and (b) the Grantee or Grantee's agents or employees, these indemnity provisions shall be valid and enforceable only to the extent of the negligence of the Grantee and those acting on its behalf.

(f) Section 8, Environmental Liability/Risk Allocation, exclusively shall govern Grantee's liability to State for Hazardous Substances and its obligation to indemnify, defend, and hold harmless State for Hazardous Substances.

10.2 Insurance Terms.

(a) Insurance Required.

(1) Grantee certifies that on the Commencement Date of this Easement it is self-insured for all the liability exposures, its self-insurance plan satisfies all State requirements, and its self-insurance plan provides coverage equal to that required in this Paragraph 10.2 and by Paragraph 10.3, Insurance Types and Limits. Grantee shall provide to State evidence of its status as a self-insured entity –Upon request by State, Grantee shall provide a written description of its financial condition and/or the self-insured funding mechanism. Grantee shall provide State with at least thirty (30) days' written notice prior to any material changes to Grantee's self-insured funding mechanism. If during the Term Grantee's self-insurance plan fails to provide coverage equal to that required in Paragraph 10.2 and Paragraph 10.3 of this Easement, Grantee shall procure additional commercial insurance coverage to meet the requirements of this Easement. The requirements in Paragraphs 10.2(a)(3) and (4) only apply where the Grantee procures additional commercial insurance to meet the requirements of this Easement.

(2) Unless State agrees to an exception, Grantee shall provide insurance issued by an insurance company or companies admitted to do business in the State of Washington and have a rating of A- or better by the most recently published edition of A.M. Best's Insurance Reports. Grantee may submit a request to the risk manager for the Department of Natural Resources to approve an exception to this requirement. If an insurer is not admitted, the insurance policies and procedures for issuing the insurance policies shall comply with Chapter 48.15 RCW and 284-15 WAC.

(3) All general liability, excess, umbrella, and pollution legal liability insurance policies must name the State of Washington, the Department of Natural Resources, its elected and appointed officials, officers, agents, and employees as an additional insured by way of endorsement.

(4) All property, builder's risk, and equipment breakdown insurance must name the State of Washington, the Department of Natural Resources, its

elected and appointed officials, officers, agents, and employees as loss payees.

(5) All insurance provided in compliance with this Easement must be primary as to any other insurance or self-insurance programs afforded to or maintained by State.

(b) Waiver.

(1) Grantee waives all rights against State for recovery of damages to the extent insurance maintained pursuant to this Easement covers these damages.

(2) Except as prohibited by law, Grantee waives all rights of subrogation against State for recovery of damages to the extent that they are covered by insurance maintained pursuant to this Easement.

(c) Proof of Insurance.

(1) Grantee shall provide State with a certificate(s) and endorsement(s) of insurance executed by a duly authorized representative of each insurer, showing compliance with insurance requirements specified in this Easement and, if requested, copies of policies to State.

(2) The certificate(s) of insurance must reference the Easement number.

(3) Receipt of such certificates, endorsements, or policies by State does not constitute approval by State of the terms of such policies.

(d) State must receive written notice before cancellation or non-renewal of any insurance required by this Easement, as follows:

(1) Insurers subject to RCW 48.18 (admitted and regulated by the Insurance Commissioner): If cancellation is due to non-payment of premium, provide State ten (10) days' advance notice of cancellation; otherwise, provide State forty-five (45) days' advance notice of cancellation or non-renewal.

(2) Insurers subject to RCW 48.15 (surplus lines): If cancellation is due to non-payment of premium, provide State ten (10) days' advance notice of cancellation; otherwise, provide State twenty (20) days' advance notice of cancellation or non-renewal.

(e) Adjustments in Insurance Coverage.

(1) State may impose changes in the limits of liability for all types of insurance as State deems necessary.

(2) Grantee shall secure new or modified insurance coverage within thirty (30) days after State requires changes in the limits of liability.

(f) If Grantee fails to procure and maintain the insurance required in this Easement within fifteen (15) days after Grantee receives a notice to comply from State, State may either:

(1) Terminate this Easement, or

(2) Procure and maintain comparable substitute insurance and pay the premiums. Upon demand, Grantee shall pay to State the full amount paid

by State, together with interest at the rate provided in Paragraph 6.3 from the date of State's notice of the expenditure until Grantee's repayment.

(g) General Terms.

(1) State does not represent that coverage and limits required under this Easement are adequate to protect Grantee.

(2) Coverage and limits do not limit Grantee's liability for indemnification and reimbursements granted to State under this Easement.

(3) The Parties shall use any insurance proceeds payable by reason of damage or destruction to Easement Property first to restore the Easement Property, then to pay the cost of the reconstruction, then to pay State any sums in arrears, and then to Grantee.

10.3 Insurance Types and Limits.

(a) General Liability Insurance.

(1) Grantee shall maintain commercial general liability insurance (CGL) or marine general liability (MGL) covering claims for bodily injury, personal injury, or property damage arising on the Easement Property and/or arising out of the Permitted Use and, if necessary, commercial umbrella insurance with a limit of not less than One Million Dollars ($1,000,000) per each occurrence. If such CGL or MGL insurance contains aggregate limits, the general aggregate limit must be at least twice the "each occurrence" limit. CGL or MGL insurance must have products-completed operations aggregate limit of at least two times the "each occurrence" limit.

(2) CGL insurance must be written on Insurance Services Office (ISO) Occurrence Form CG 00 01 (or a substitute form providing equivalent coverage). All insurance must cover liability arising out of premises, operations, independent contractors, products completed operations, personal injury and advertising injury, and liability assumed under an insured contract (including the tort liability of another party assumed in a business contract) and contain separation of insured (cross-liability) condition.

(3) MGL insurance must have no exclusions for non-owned watercraft.

(b) Workers' Compensation.

(1) State of Washington Workers' Compensation.

(i) Grantee shall comply with all State of Washington workers' compensation statutes and regulations. Grantee shall provide workers' compensation coverage for all employees of Grantee. Coverage must include bodily injury (including death) by accident or disease, which arises out of or in connection with the Permitted Use or related activities.

(ii) If Grantee fails to comply with all State of Washington workers' compensation statutes and regulations and State incurs fines or is

required by law to provide benefits to or obtain coverage for such employees, Grantee shall indemnify State. Indemnity shall include all fines; payment of benefits to Grantee, employees, or their heirs or legal representatives; and the cost of effecting coverage on behalf of such employees.

(2) Longshore and Harbor Workers' and Jones Acts. The Longshore and Harbor Workers' Act (33 U.S.C. Section 901 *et seq.*) and/or the Jones Act (46 U.S.C. Section 30104) may require Grantee to provide insurance coverage in some circumstances. Grantee shall ascertain if such insurance is required and, if required, shall maintain insurance in compliance with the law. Grantee is responsible for all civil and criminal liability arising from failure to maintain such coverage.

(c) Employers' Liability Insurance. Grantee shall procure employers' liability insurance, and, if necessary, commercial umbrella liability insurance with limits not less than One Million Dollars ($1,000,000) each accident for bodily injury by accident and One Million Dollars ($1,000,000) each employee for bodily injury by disease.

(d) Property Insurance.

(1) Grantee shall buy and maintain property insurance covering all real property and fixtures, equipment, Improvements and betterments (regardless of whether owned by Grantee or State). Such insurance must be written on an all risks basis and, at minimum, cover the perils insured under ISO Special Causes of Loss Form CP 10 30, and cover the full replacement cost of the property insured. Such insurance may have commercially reasonable deductibles. Any coinsurance requirement in the policy must be waived.

(2) Grantee shall buy and maintain equipment breakdown insurance covering all real property and fixtures, equipment, Improvements and betterments (regardless of whether owned by Grantee or State) from loss or damage caused by the explosion of equipment, fired or unfired vessels, electric or steam generators, electrical arcing, or pipes.

(3) In the event of any loss, damage, or casualty that is covered by one or more of the types of insurance described above, the Parties shall proceed cooperatively to settle the loss and collect the proceeds of such insurance, which State shall hold in trust, including interest earned on such proceeds, for use according to the terms of this Easement. The Parties shall use insurance proceeds in accordance with Paragraph 10.2(g)(3).

(4) When sufficient funds are available, using insurance proceeds described above, the Parties shall continue with reasonable diligence to prepare plans and specifications for, and thereafter carry out, all work necessary to:

(i) Repair and restore damaged Improvements to their former condition, or

(ii) Replace and restore damaged Improvements with new Improvements on the Easement Property of a quality and usefulness at least equivalent to, or more suitable than, damaged Improvements.

(e) Builder's Risk Insurance.

(1) Grantee shall procure and maintain in force, or require its contractor(s) to procure and maintain in force, builder's risk insurance on the entire work during the period construction is in progress and until completion of the project and acceptance by State. Such insurance must be written on a completed form and in an amount equal to the value of the completed Improvements, subject to subsequent modifications to the sum. The insurance must be written on a replacement cost basis. The insurance must name Grantee, all contractors, and subcontractors in the work as insured.

(2) Insurance described above must cover or include the following:

(i) All risks of physical loss except those specifically excluded in the policy, including loss or damage caused by collapse;

(ii) The entire work on the Easement Property, including reasonable compensation for architect's services and expenses made necessary by an insured loss;

(iii) Portions of the work located away from the Easement Property but intended for use at the Easement Property, and portions of the work in transit;

(iv) Scaffolding, falsework, and temporary buildings located on the Easement Property; and

(v) The cost of removing debris, including all demolition as made legally necessary by the operation of any law, ordinance, or regulation.

(3) Grantee or Grantee's contractor(s) is responsible for paying any part of any loss not covered because of application of a deductible contained in the policy described above.

[(4) Grantee or Grantee's contractor(s) shall buy and maintain equipment breakdown insurance covering insured objects during installation and until final acceptance by permitting authority. If testing is performed, such insurance must cover such operations. The insurance must name Grantee, all contractors, and subcontractors in the work as insured.

(f) Protection and Indemnity Insurance (P&I). Whenever any Work requires a vessel to be operated on the property, Grantee or Grantee's contractor(s) shall procure and maintain P&I insurance with limits of liability not less than One Million Dollars ($1,000,000) for the duration of such Work. The P&I insurance must cover, at a minimum, all claims relating to injuries or damages to persons or property sustained in, on, or about the property; fuel spills; wreck removal; salvage; injuries to passengers and crew of the vessel; and damages to nets and fishing lines. If necessary, Grantee shall procure and maintain commercial

umbrella liability insurance covering claims for these risks. Grantee shall submit proof of this P&I insurance to State prior to Commencing any such Work.]

(g) Hull Insurance. Grantee or Grantee's contractor shall procure and maintain hull insurance for each vessel owned and/or operated by the Grantee or Grantee's contractor on the Easement Property. The coverage amount of each hull insurance policy must be equal to the value of the covered vessel.

10.4 Financial Security.

(a) On the Commencement Date of this Easement, Grantee is not required to procure and maintain a corporate security bond or other financial security ("Security"). During the Term, State may require Grantee to procure and maintain Security upon any of the events listed in Paragraph 10.4(c)(1). Grantee's failure to maintain the Security in the required amount during the Term constitutes a breach of this Easement.

(b) All Security must be in a form acceptable to State.

(1) Bonds must be issued by companies admitted to do business within the State of Washington and have a rating of A-, Class VII or better, in the most recently published edition of A.M. Best's Insurance Reports, unless State approves an exception in writing. Grantee may submit a request to the Risk Manager for the Department of Natural Resources for an exception to this requirement.

(2) Letters of credit, if approved by State, must be irrevocable, allow State to draw funds at will, provide for automatic renewal, and comply with RCW 62A.5-101, *et. seq*.

(3) Savings account assignments, if approved by State, must allow State to draw funds at will.

(c) Adjustment in Amount of Security.

(1) State may require an adjustment in the Security amount:

(i) As a condition of approval of assignment of this Easement,

(ii) Upon a material change in the condition or disposition of any Improvements, or

(iii) Upon a change in the Permitted Use.

(2) Grantee shall deliver a new or modified form of Security to State within thirty (30) days after State has required adjustment of the amount of the Security.

(d) Upon any breach by Grantee in its obligations under this Easement, State may collect on the Security to offset the liability of Grantee to State. Collection on the Security does not (1) relieve Grantee of liability, (2) limit any of State's other remedies, (3) reinstate the Easement or cure the breach or (4) prevent termination of the Easement because of the breach.

SECTION 11 MAINTENANCE AND REPAIR

11.1 State's Repairs. State shall not be required to make any alterations, maintenance, replacements, or repairs in, on, or about the Easement Property, or any part thereof, during the Term.

11.2 Grantee's Repairs and Maintenance.

(a) Grantee shall, at its sole cost and expense, keep and maintain the Easement Property and all Grantee-Owned Improvements in good order and repair, in a clean, attractive, and safe condition. Grantee shall repair all damage caused or permitted by Grantee to Improvements Owned by Others on the Easement Property.

(b) Grantee shall, at its sole cost and expense, make any and all additions, repairs, alterations, maintenance, replacements, or changes to the Easement Property or to any Grantee-Owned Improvements on the Easement Property that may be required by any public authority having jurisdiction over the Easement Property and requiring it for public health, safety and welfare purposes.

(c) Except as provided in Paragraph 11.2(d), all additions, repairs, alterations, maintenance, replacements or changes to the Easement Property and to any Grantee-Owned Improvements on the Easement Property shall be made in accordance with, and ownership shall be governed by, Section 7 above.

(d) Routine maintenance and repair are acts intended to prevent a decline, lapse, or cessation of the Permitted Use and associated Grantee-Owned Improvements. Routine maintenance or repair that does not require regulatory permits does not require authorization from State pursuant to Section 7.

(e) Upon completion of maintenance activities, Grantee shall remove all debris and restore the Easement Property to the condition prior to the commencement of Work.

SECTION 12 DAMAGE OR DESTRUCTION

12.1 Damage to Improvements.

(a) In the event of any damage to or destruction of any Improvements on the Easement Property, Grantee shall immediately notify State, with subsequent written notice to State within five (5) days.

(b) Grantee shall be solely responsible for any reconstruction, repair, or replacement of any Grantee-Owned Improvements. If Grantee elects not to reconstruct, repair, or replace all or a portion of any damaged Improvements, Grantee shall promptly remove any damaged or destroyed Improvements and restore the Easement Property. Any reconstruction, repair, or replacement of Improvements is governed by Section 7 Improvements, Personal Property, and Work, and Section 11, Maintenance and Repair, and any Additional Obligations in Exhibit B.

(c) If Grantee is in breach of this Easement at the time damage or destruction occurs to Grantee-Owned Improvements, State may elect to terminate the Easement without giving Grantee an opportunity to cure, and State may retain any insurance proceeds payable as a result of the damage or destruction.

12.2 Damage to Land or Natural Resources

(a) In the event of any damage to or destruction to the land or natural resources on the Easement Property, Grantee shall immediately notify State, with subsequent written notice to State within five (5) days. In the event of any damage or destruction to land or natural resources on adjacent state-owned aquatic lands that is attributable to Grantee's use of the Property, to the Permitted Use, or to related activities, Grantee shall immediately notify State, with subsequent written notice to State within five (5) days.

(b) Grantee, at Grantee's sole cost, shall remedy any damages to land or natural resources on the Easement Property and adjacent state-owned aquatic lands that are attributable to Grantee's use of the Property, the Permitted Use, or related activities, in accordance with a plan approved by State. Grantee shall also compensate State for any lost or damaged natural resource values in accordance with Paragraph 12.2(c).

(c) Compensation for lost resource values:

(1) If damages to the land or natural resources result in lost or damaged natural resource values, Grantee shall compensate State with (1) monetary compensation; (2) the completion of a project approved by State that includes replacing, enhancing, or otherwise providing in-kind habitats, resources, or environments on other state-owned aquatic lands in order to offset the damage and impacts; or (3) a mixture of both monetary compensation and a project. State shall have the discretion to determine if Grantee will compensate with monetary compensation, a project, or both. If State requires monetary compensation, the value of damages shall be determined in accordance with Paragraph 12.2(c)(2).

(2) If State requires monetary compensation under Paragraph 12.2(c)(1), unless the Parties otherwise agree on the value, a three-member panel of professional appraisers or resource economists will determine the measure of lost resource values, and issue a written decision. The appraisers or resource economists shall be qualified to assess economic value of natural resources. State and Grantee each shall appoint and compensate one member of the panel. By consensus, the two appointed members shall select the third member, who will be compensated by State and Grantee equally. The panel shall base the calculation of compensation on generally accepted valuation principles. The written decision of the majority of the panel shall bind the Parties.

(d) If damage to land or natural resources on the Easement Property or adjacent state-owned aquatic lands are attributable to Grantee's use of the Property, to the

Permitted Use, or to related activities, or if such damage occurs when Grantee is in breach of the Easement, State may elect to terminate the Easement in accordance with Section 14. If State elects to terminate the Easement, Grantee is still responsible for restoring any damages to land or natural resources on the Easement Property and adjacent state-owned aquatic lands, and for compensating State for any lost resource values in accordance with Paragraph 12.2(c). State may retain any insurance proceeds payable as a result of the damage or destruction.

(e) State may, with or without terminating the Easement, at the sole expense of Grantee, remedy any damages and complete a project that offsets lost or damaged natural resource values. If State takes any such actions, upon demand by State, Grantee shall pay all costs incurred by State.

12.3 State's Waiver of Claim. State does not waive any claims for damage or destruction of the Easement Property or adjacent state-owned aquatic lands unless State provides written notice to Grantee of each specific claim waived.

12.4 Insurance Proceeds. Grantee's duties under Paragraphs 12.1 and 12.2 are not conditioned upon the availability of any insurance proceeds to Grantee from which the cost of repairs may be paid. The Parties shall use insurance proceeds in accordance with Paragraph 10.2(g)(3).

SECTION 13 CONDEMNATION

In the event of condemnation, the Parties shall allocate the condemnation award between State and Grantee based upon the ratio of the fair market value of (1) Grantee's rights in the Easement Property and Grantee-Owned Improvements and (2) State's interest in the Easement Property; the reversionary interest in Grantee-Owned Improvements, if any; and State-Owned Improvements, if any. In the event of a partial taking, the Parties shall compute the ratio based on the portion of Easement Property or Improvements taken. If Grantee and State are unable to agree on the allocation, the Parties shall submit the dispute to binding arbitration in accordance with the rules of the American Arbitration Association.

SECTION 14 REMEDIES AND TERMINATION

14.1 Termination by Breach. State may terminate this Easement upon Grantee's failure to cure a breach of the terms and conditions of this Easement. Unless otherwise stated in this Easement, State shall provide Grantee written notice of breach, and Grantee shall have sixty (60) days after receiving the notice to cure the breach. State may extend the cure period if breach is not reasonably capable of cure within sixty (60) days. This sixty (60) day cure period does not apply where State terminates this Easement under Paragraph 10.2(f) or Section 12.

14.2 Termination by Nonuse. If Grantee does not use the Easement Property for a period of three (3) successive years, this Easement terminates without further action by State and Grantee's rights revert to State. Grantee shall still be responsible for complying with all end of Term requirements.

14.3 Termination by Grantee. Grantee may terminate this Easement upon providing State with sixty (60) days written notice of intent to terminate. If Grantee terminates under this Paragraph, the date of Grantee's termination shall be deemed the Termination Date and Grantee shall comply with all end of Term requirements. Grantee is not entitled to any refunds of Easement fees already paid to State.

14.4 Remedies Not Exclusive. The remedies specified under this Section 14 are not exclusive of any other remedies or means of redress to which State is lawfully entitled for Grantee's breach or threatened breach of any provision of this Easement.

SECTION 15 NOTICE AND SUBMITTALS

15.1 Notice. Following are the locations for delivery of notice and submittals required or permitted under this Easement. Any Party may change the place of delivery upon ten (10) days' written notice to the other.

State: **DEPARTMENT OF NATURAL RESOURCES**
Orca-Straits District
919 N Township Street
Sedro-Woolley, WA 98284

Grantee: **PUBLIC UTILITY DISTRICT NO. 1 OF SNOHOMISH COUNTY**
PO Box 1107
Everett, WA 98206

The Parties may deliver any notice in person, by facsimile machine, or by certified mail. Depending on the method of delivery, notice is effective upon personal delivery, upon receipt of a confirmation report if delivered by facsimile machine, or three (3) days after mailing. All notices must identify the Easement number. On notices transmitted by facsimile machine, the Parties shall state the number of pages contained in the notice, including the transmittal page, if any.

15.2 Contact Persons. On the Commencement Date, the following persons are designated day-to-day contact persons. Any Party may change the Contact Person upon reasonable notice to the other.

State: **DEPARTMENT OF NATURAL RESOURCES**

Orca-Straits District
919 N Township Street
Sedro-Woolley, WA 98284
Phone number: 360-856-3500
Fax number: 360-856-2150
E-mail: brenda.werden@dnr.wa.gov

Grantee: **Public Utility District No. 1 of Snohomish County**
Maureen Barnes
Manager of Real Estate Services
Phone number: 425-783-4373
Fax number N/A
E-mail: mlbarnes@snopud.com

SECTION 16 MISCELLANEOUS

16.1 Authority. Grantee and the person or persons executing this Easement on behalf of Grantee represent that Grantee is qualified to do business in the State of Washington, that Grantee has full right and authority to enter into this Easement, and that each and every person signing on behalf of Grantee is authorized to do so. Upon State's request, Grantee shall provide evidence satisfactory to State confirming these representations.

16.2 Successors and Assigns. Subject to the limitations set forth in Section 9, this Easement binds and inures to the benefit of the Parties, their successors, and assigns.

16.3 Headings. The headings used in this Easement are for convenience only and in no way define, limit, or extend the scope of this Easement or the intent of any provision.

16.4 Entire Agreement. This Easement, including the exhibits, attachments, and addenda, if any, contains the entire agreement of the Parties. This Easement merges all prior and contemporaneous agreements, promises, representations, and statements relating to this transaction or to the Easement Property.

16.5 Waiver.

(a) The waiver of any breach of any term, covenant, or condition of this Easement is not a waiver of such term, covenant, or condition; of any subsequent breach of the same; or of any other term, covenant, or condition of this Easement. State's acceptance of a payment is not a waiver of any preceding or existing breach other than the failure to pay the particular payment that was accepted.

(b) The renewal of the Easement, extension of the Easement, or the issuance of a new Easement to Grantee, does not waive State's ability to pursue any rights or remedies under the Easement.

16.6 Cumulative Remedies. The rights and remedies of State under this Easement are cumulative and in addition to all other rights and remedies afforded by law or equity or otherwise.

16.7 Time is of the Essence. TIME IS OF THE ESSENCE as to each and every provision of this Easement.

16.8 Language. The word "Grantee" as used in this Easement applies to one or more persons and regardless of gender, as the case may be. The singular includes the plural, and the neuter includes the masculine and feminine. If there is more than one Grantee, their obligations are joint and several. The word "persons," whenever used, shall include individuals, firms, associations, and corporations. The word "Parties" means State and Grantee in the collective. The word "Party" means either or both State and Grantee, depending on the context.

16.9 Invalidity. The invalidity, voidness, or illegality of any provision of this Easement does not affect, impair, or invalidate any other provision of this Easement.

16.10 Applicable Law and Venue. This Easement is to be interpreted and construed in accordance with the laws of the State of Washington. Venue for any action arising out of or in connection with this Easement is in the Superior Court for Thurston County, Washington.

16.11 Statutory Reference. Any reference to a statute or rule means that statute or rule as presently enacted or hereafter amended or superseded.

16.12 Recordation. At Grantee's expense and no later than thirty (30) days after receiving the fully-executed Easement, Grantee shall record this Easement in the county in which the Easement Property is located. Grantee shall include the parcel number of the upland property used in conjunction with the Easement Property, if any. Grantee shall provide State with recording information, including the date of recordation and file number. If Grantee fails to record this Easement, State may record this Easement and Grantee shall pay the costs of recording upon State's demand.

16.13 Modification. No modification of this Easement is effective unless in writing and signed by both Parties. Oral representations or statements do not bind either Party.

16.14 Survival. Any obligations of Grantee not fully performed upon termination of this Easement do not cease, but continue as obligations of the Grantee until fully performed.

16.15 Exhibits and Attachments. All referenced exhibits and attachments are incorporated in this Easement unless expressly identified as unincorporated.

THIS AGREEMENT requires the signature of all Parties and is effective on the date of the last signature below.

PUBLIC UTILITY DISTRICT NO. 1 of SNOHOMISH COUNTY

Dated: _____, 2025__ _____

By: F. COLIN WILLENBROCK
Title: Snohomish PUD Chief Operating and Legal Officer

Address: PO Box 1107
Everett, WA
Phone: 425-783-8688

STATE OF WASHINGTON
DEPARTMENT OF NATURAL RESOURCES

Dated: _____, 2025

_____
By: KATIE ROSE ALLEN
Title: Deputy Supervisor for Forest Regulation and Aquatic Resources
Address: 1111 Washington Street SE
MS 47207
Olympia, WA 98504

Aquatic Lands Easement
Template approved as to form this
10th day of January 2022
Jennifer Clements, Assistant
Attorney General

REPRESENTATIVE ACKNOWLEDGMENT
Notarized online using audio-video communication

STATE OF WASHINGTON)
) ss
County of)

I certify that I know or have satisfactory evidence that F. COLIN WILLENBROCK is the person who appeared before me, and said person acknowledged that they signed this instrument, on oath stated that they were authorized to execute the instrument and acknowledged it as the Chief Operating and Legal Officer of Snohomish County PUD to be the free and voluntary act of such party for the uses and purposes mentioned in the instrument.
This notarial act involved the use of communication technology.

Dated: _____, 2025

_____
(Signature)

(Seal or stamp)

(Print Name)

Notary Public in and for the State of Washington, residing at

My appointment expires _____

STATE ACKNOWLEDGMENT
Notarized online using audio-video communication

STATE OF WASHINGTON)
) ss.
County of)

I certify that I know or have satisfactory evidence that KATIE ROSE ALLEN is the person who appeared before me, and said person acknowledged that they signed this instrument, on oath stated that they were authorized to execute the instrument and acknowledged it as the Deputy Supervisor for Forest Regulation and Aquatic Resources of the Department of Natural Resources, to be the free and voluntary act of such party for the uses and purposes mentioned in the instrument.
This notarial act involved the use of communication technology.

Dated: _____, 2025

_____
(Signature)

(Seal or stamp)

_____
(Print Name)

Notary Public in and for the State of Washington, residing at

_____

My appointment expires _____

EXHIBIT A
PROPERTY DESCRIPTION

Agreement Number 51-101635

1. LEGAL DESCRIPTION OF THE EASEMENT PROPERTY:
A 20 FOOT WIDE AQUATIC EASEMENT ACROSS THAT PORTION OF STATE OF WASHINGTON SUBMERGED LANDS LYING BETWEEN SECTIONS 8 AND SECTION 25, TOWNSHIP 29 NORTH, RANGE 4 EAST OF THE WILLAMETTE MERIDIAN BEING 10 FEET ON EACH SIDE OF THE FOLLOWING DESCRIBED CENTERLINE: BEGINNING AT A POINT ON THE LINE OF EXTREME LOW TIDE WHICH BEARS NORTH 44º17'31" EAST 946.42 FEET FROM AN EXISTING IRON PIPE MONUMENT DENOTING THE INTERSECTION OF CAMANO DRIVE AND SARATOGA DRIVE AS SHOWN ON THE PLAT OF HAT ISLAND DIVISION NO. "A" AS PER PLAT RECORDED MAY 14, 1962 UNDER AUDITOR'S FILE NO. 1432452 AND NORTH 41º 45' 07" EAST 345.28 FEET FROM A 3.5 INCH DIAMETER BRASS DISK NATIONAL GEODETIC SURVEY MONUMENT STAMPED GEDNEY NORTH NO. 3 1971";
THENCE NORTH 58° 40' 54" EAST 135.42 FEET;
THENCE NORTH 57° 15' 54" EAST 393.97 FEET;
THENCE NORTH 55° 52' 25" EAST 529.50 FEET;
THENCE NORTH 49° 37' 56" EAST 302.01 FEET;
THENCE NORTH 69° 22' 20" EAST 446.11 FEET;
THENCE NORTH 89° 39' 09" EAST 250.00 FEET;
THENCE SOUTH 70° 20' 51" EAST 250.00 FEET;
THENCE SOUTH S47° 23' 23" EAST 541.86 FEET;
THENCE SOUTH 42° 14' 51" EAST 569.68 FEET;
THENCE SOUTH 46° 56' 01" EAST 1256.92 FEET;
THENCE SOUTH 56° 17' 07" EAST 7528.51 FEET;
THENCE SOUTH 54° 15' 30" EAST 642.04 FEET;
THENCE SOUTH 45° 44' 19" EAST 522.44 FEET;
THENCE SOUTH 28° 59' 07" EAST 834.63 FEET;
THENCE SOUTH 27° 37' 45" EAST 1279.94 FEET;
THENCE SOUTH 18° 48' 02" EAST 2228.91 FEET;
THENCE SOUTH 08° 30' 55" EAST 693.91 FEET;
THENCE SOUTH 05° 42' 09" WEST 628.33 FEET;
THENCE SOUTH 02° 24' 25" EAST 785.58 FEET;
THENCE SOUTH 16° 02' 25" EAST 924.25 FEET;
THENCE SOUTH 28° 41' 31" EAST 1150.10 FEET;
THENCE SOUTH 37° 21' 12" EAST 599.49 FEET;

THENCE SOUTH 30° 38' 52" EAST 1315.17 FEET;
THENCE SOUTH 52° 21' 36" EAST 886.69 FEET;
THENCE SOUTH 58° 50' 26" EAST 863.90 FEET;
THENCE SOUTH 73° 09' 19" EAST 1257.14 FEET;
THENCE SOUTH 74° 27' 23" EAST 1638.77 FEET;
THENCE SOUTH 75° 21' 48" EAST 978.24 FEET;
THENCE SOUTH 74° 43' 03" EAST 1000.37 FEET;
THENCE SOUTH 56° 05' 57" EAST 56.48 FEET;
THENCE SOUTH 57° 34' 05" EAST 282.78 FEET;
THENCE SOUTH 79° 14' 24" EAST 416.73 FEET TO THE INNER HARBOR LINE AS SHOWN ON THAT SURVEY FOR THE PORT OF EVERETT, PORT MANAGEMENT AGREEMENT NO. 20-80027, RECORDED SEPTEMBER 19, 2002, UNDER AUDITORS FILE NUMBER 200209195004, RECORDS OF SNOHOMISH COUNTY, WASHINGTON AND THE TERMINUS OF SAID EASEMENT CENTERLINE.
SITUATE IN SNOHOMISH COUNTY, WASHINGTON.

2. SQUARE FOOTAGE OF EASEMENT:

   Total square feet **623,805**

EXHIBIT B

1. DESCRIPTION OF PERMITTED USE

A. Existing Facilities.
None.

B. Proposed Work.
State authorizes Grantee to conduct the following Proposed Work on the Easement Property: Installation of a three-phase electric submarine cable between Hat (Gedney) Island and Everett, WA. The new cable will be installed using horizontal directional drilling at both landfalls. The HDD pathway on the Hat Island side will bore approximately 50 feet below the surface and avoid eelgrass to daylight through the seafloor at approximately -30' MLLW or approximately 355 feet from the OHWM. The HDD pathway on the Port of Everett side will bore to approximately 75 feet beneath the substrate surface and daylight at approximately -50' MLLW or approximately 920 feet from the HDD entry point. Conduit will be installed in the HDD bored pathway and the cable will be installed into the conduit and connected to the submarine terminal station. The cable will be directly laid on the seafloor using a cable laying vessel between Hat Island and the Port of Everett. The maximum seafloor depth is approximately 454 feet below Mean-Low-Low-Water (MLLW).

Grantee's Proposed Work is considered Work and is subject to the terms and conditions of this Easement. If the Proposed Work is not commenced within five years of the Commencement Date of the Easement, or if Grantee is required to renew, extend, modify, or obtain a new regulatory permit for the Proposed Work, Grantee shall obtain State's prior written consent before conducting the Proposed Work pursuant to Section 7.3 of the Easement. The Proposed Work is shown in Attachment (1) to this Exhibit B.

C. Permits for Proposed Work.
Grantee has secured the following permits for the Proposed Work:

WA Dept. of Fish & Wildlife
Hydraulic Project Approval (HPA)

WA Dept. of Ecology
Section 401 Water Quality Certification
Coastal Zone Management Act (CZMA) Consistency Determination

Army Corps of Engineers
Individual DA Permit
Section 404, Section 10

Snohomish County
Shoreline Permit – substantial development and conditional use
Land Disturbing Activity Permit
Flood Hazard Permit

City of Everett
Public Works
Critical areas review
Shoreline Conditional Use

2. ADDITIONAL OBLIGATIONS

Except for the Proposed Work authorized in Section 1.B. of this Exhibit B**,** State has not authorized Grantee to conduct any Work on the Easement Property. Where Work will need to be conducted to meet the Additional Obligations below, Grantee shall obtain State's prior written consent in accordance with Section 7.3 of this Easement and obtain all necessary regulatory permits prior to commencing such Work.

(i). Grantee shall monitor and submit reports as specified in Attachment (1) to this Exhibit B (if applicable).

(ii). Grantee shall avoid scouring, shading, and damage to native submerged aquatic vegetation by anchoring or mooring vessels in a location that is at least twenty-five (25) feet from native aquatic vegetation.

(iii) Grantee shall not spud or anchor within kelp or eelgrass beds.

Attachment (1) to Exhibit B
Plans and Specifications of Work

SECTION
35 80 00

35 80 00 SUBMARINE CABLE INSTALLATION

PART 1 – GENERAL

1.01 SUMMARY

A. General

The purpose of this Division 35 of the Project is to install a new armored submarine electrical and fiber optic cable from the Port of Everett (POE) in Everett, Washington to Hat Island Marina to provide a reliable source of power for the island.

Other contracts associated with this project have already been awarded or are in the process of being awarded to other contractors. The Site Infrastructure contract will be substantially complete prior to starting the Work outlined in this contract.

Substantial Completion

This Specification describes the requirements for the installation of approximately 32,000 feet (about 6.6 miles) of new 12.47 kV submarine cable system including fiber optics, and terminations in vaults at POE and Hat Island. Other requirements include the monitoring, inspecting, witnessing testing and acceptance of the submarine cable upon delivery to the Puget Sound region. Also required is the documentation of the cable installation through submittals and construction record documents, along with the electrical and fiber optic termination, testing those terminations, installation and testing of the remaining components of the cathodic protection system and finally the commissioning and testing of the system to insure full functionality. This includes OTDR, VLF Acceptance Testing, VLF Tan Delta Testing, TDR phase cable testing, phase rotation identification, thermal temperature testing of terminations under load, all to be completed by the CONTRACTOR and witnessed by the DISTRICT.

The CONTRACTOR is also required to review Cable Supplier supplied data and respond to Cable Supplier's comments and requirements associated with the installation. Furthermore, the CONTRACTOR is required to coordinate with the Site Development Contractor, which includes requesting data such as conduit pull coefficients, vault and as-built details, etc. along with providing the Site Development Contractor with certain requirements such a conduit bell ends, pulling rope, etc.

The route of the Submarine Cable in deep water is documented in the Contract Documents. Submittals, Schedules, Shop Drawings, A Project Installation Manual, Commissioning Plan, Storage & Handling of Spare & Surplus Parts (including design documents for Spare/Surplus Cable reel), Design and Construction Record Drawing requirements of the CONTRACTOR are to be found within Section 01 33 00.

B. Scope of Work

The Work within Division 35 includes:

1. Reviewing and commenting on various Cable Supplier submittals and delivery documents.
2. Selecting and securing the location for cable storage and handling (if required).
3. Coordination with Cable Supplier, and the Cable Supplier's delivery vessel operator, as required to clear US customs.
4. Receiving, storage and handling of cable from DISTRICT's Cable Supplier, as required for immediate installation, or for storage (if required).
5. Witnessing and approving the electrical testing performed by Cable Supplier upon delivery of the cable.
6. Upon acceptance of the cable testing, assume custody and responsibility for the cable through storage (if required) handling, installation and post installation testing.
7. Coordinate and execute all cable loading and transportation as required between initial delivery and cable installation.
8. Installation of the DISTRICT-furnished submarine cable and ancillary components.
9. Installation of remaining cathodic protection systems not already installed by the site development Contractor.
10. On-site electrical testing and commissioning of a new 12.47 kv and fiber optic cable system.
11. Testing and assistance with commissioning of the cathodic protection system.
12. Coordination and compliance with regulatory and stakeholder requirements.
13. Coordination and compliance with Snohomish County PUD energization requirements.
14. Furnishing and completion of all required reports, as-builts and drawings.

C. Work Included

The Work includes all services, labor, materials, tools, equipment, and accessories required for the installation and testing of the 12.47 kV cable systems as specified in these documents. It includes a total of approximately 35,000 feet of submarine cable to be handled by the CONTRACTOR. In addition to its continuous, splice free length from Port of Everett to Hat Island, the length includes both surplus and spare cable for future repairs. The maximum seafloor depth is approximately 454 feet below Mean-Low-Low-Water (MLLW). The scope of work includes complying with all the Contract Documents, including the design and installation of the following:

1. Three-phase armored "dry-type" Submarine cable. (Furnished by DISTRICT under separate contract, refer to cable specifications in the appendix) along with removal of any man-made underwater obstructions or avoidance of natural obstructions. Refer to Contract Drawings for depths and submarine cable route locations.
2. Installation of electric power terminations (furnished by DISTRICT and sized for the submarine cable).
3. Installation of the applicable mounting hardware (non-metallic or 316 stainless-steel, furnished by DISTRICT) within the splice vaults.
4. Sealing of the elbows and placement of the elbows on temporary parking stands (furnished by the CONTRACTOR) to prevent water intrusion or contamination.
5. Installation of the insulated termination rings (supplied by the DISTRICT) to a stainless-steel load bearing plates (supplied by the CONTRACTOR) within both Splice Vaults, including:
    a. stripping of armored submarine cable into components;
    b. welding of armor wires to insulated termination rings;
    c. water sealing of the insulated armor wire termination rings; and
    d. water sealing of all conduits.
6. Termination and routing of the fiber optics cable to the appropriate fiber optic vaults at each end as directed by the DISTRICT, for future use.
7. Grounding and bonding of the cable sheaths and separate equipment grounding conductors in the vault/electrical box at both ends.
8. Grounding of the cable armor through suitable Solid State Polarization Cells (supplied by the DISTRICT) at the vault/electrical box at both ends for cathodic protection, per the Contract Drawings.
9. Cable anchoring systems, as specified or required. This includes furnishing and installing up to 200 feet of split pipe required in water (from 0 – 100’ depth) to prevent suspensions of 7 feet or greater.
10. Provision of a Construction Record or “as-built” survey coordinates as well as “plan and profile” drawings for all sections of the installed cable. This survey shall comply to the WA DNR survey requirements and filed with the DISTRICT at the end of the project.
11. Visual inspection, by ROV, of the underwater sections of the installed submarine cable, concurrent with the cable installation, to ensure all requirements of the specifications are met and, if not in compliance, bring into compliance as necessary at no additional cost. Provide video documentation

showing the "as-laid" condition of all underwater sections of the exposed submarine cable. CONTRACTOR shall have a secondary (or redundant) ROV available at all times during the cable lay operation in the event the primary becomes inoperable and is not capable of performing the duties required in this Specification.

12. Electrical testing and mechanical inspections of the electrical systems, along with miscellaneous consumables and parts as required by this Specification.

13. Fiber optic testing and mechanical inspections of the fiber optic systems, along with miscellaneous consumables and parts as required by this Specification.

14. Obtain the clearances and permits required for the general conduct of business or work in the State of Washington, Snohomish County and the City of Everett.

15. Compliance with all required regulatory permits and reports identified in the Contract Documents or obtained after the Bid Time of this Work, but prior to installation.

16. Perform pre-installation Side Scan Sonar efforts of the Hat Island and Port of Everett approaches (320 to 30 feet of depth) to the underwater HDD ends to refine the route to avoid areas of potential suspensions.

D. Products and Equipment Supplied and Installed by the CONTRACTOR (including, but are not limited to):

1. Furnishing and operation of a marine cable laying vessel, or combination of vessels, equipped with the dynamic positioning necessary to install a submarine cable of the specified length, depth and weight, warning chase boat(s), surveyor, cable floating bladders, boats to position floating cables or install split pipe, divers, winches, pulling ropes/cables, lubricants, conduit bell ends, temporary pulleys, sheaves, tension meters, remote operated underwater vehicles (ROV), and any related hardware or ancillary parts required to for a complete installation per the Contract Documents.

2. Miscellaneous hardware required for a complete installation and a complete working electrical system.

3. Sealing of conduit in two places (at the interface between the Splice Vault at POE and Splice Vault at Hat Island and the 10 inch HDD HDPE conduit) with the use of a hard simplex style plug (other names include: Wedge Seal, Cable Termination Plug, Split Duct Plug, Jack Moon Duct Plug or Cable Termination Seals) and a closed foam sealant before and after the hard plug, such as Polywater AFT Foam Sealant, Polywater FST-250 foam duct sealant, FILOSEAL+HD Cable Duct Seal, or approved equal.

4. Roxtec (H SEAL - H1-207/96/60/F2S/OC30.5) Quantity-2, for installation at each HDD exit point, post installation. Supplier information below:

Darren Wesneske, Offshore Wind Segment Manager

Ph: 713-416-7561; Email: darren.wesneske@roxtec.com

5. Tools, dies, presser, and all necessary incidental materials required for a complete submarine cable installation.

6. The CONTRACTOR shall fabricate and furnish a Spare Cable Reel to hold and store any surplus and spare cable. The CONTRACTOR shall transfer all surplus and spare cable to this reel and deliver it to the DISTRICT's Operations Center at the end of the Project. Spare cable reel design was conducted by the Cable Supplier and is located in Appendix.

7. Load bearing plates inside both vaults.

E. Products Furnished by the DISTRICT and installed by the CONTRACTOR:

1. 316 stainless steel or nonmetallic cable supports and cable ties to support the full-service loop for the three phases and 200 Amp elbows at both the Electrical Splice Vaults at POE and Hat Island (See Contract Drawings).

2. Approximately 35,000 feet of continuous length, 3-phase cable specified herein.

3. Two insulated armor wire termination rings which will terminate the armor wire and connect to a steel load bearing plate within the Power Splice Vaults at Hat Island and POE.

4. Six each - 200 Amp load break 12.47 kV elbows (plus three furnished spares for a total of nine). The spare elbows are provided in case there is a problem with the termination of submarine cable phase conductors.

5. Installed infrastructure on both the Hat Island and Port of Everett landing sites, including:

   a. Splice, switch, and fiberoptic vaults.

   b. 10" horizontally directionally drilled conduit from land to depth.

   c. Conduits and conductors for tie-in to existing.

6. Cathodic Protection Equipment, furnished and installed by the DISTRICT:

   a. Sack anodes on Hat Island within Mesa CP Glen 4 locking, grey, cast iron cover, boxes;

   b. One half-cell within a Mesa CP Glen five locking grey cast iron cover box;

   c. Conduit and wiring between CP boxes/anodes and the power splice vaults (both landing sites); and

d. NEMA 4X stainless steel locking enclosure attached to the spice vault on Hat Island, and a NEMA 4X stainless steel locking enclosure attached to the power pole at POE.

7. Cathodic Protection Equipment, furnished and installed by the CONTRACTOR (remainder of equipment needed for a complete, fully functioning Cathodic protection system):
   a. ACR Data Logger system (data logger, computer monitor cord and the ACR Trendreader computer program) Model number SRP-007-1.5MB (ACR Catalog No. 01-0152
   b. ACR Trendreader Program (USB Full Install SKU: 01-228) and the Logger USB Interface Cable (ACR Catalog No. IC-102).
   c. Dairyland PCR 10 kA with-3V/+1V Blocking Voltage (quantity-2) one for Hat Island enclosure and another for the POE enclosure.
   d. CONTRACTOR to furnish a resistor, size determined during commissioning of the system by others, for installation between the termination ring and the anodes (Hat side only).
   e. Submarine cable armor shall be spot welded to the armor termination ring supplied by the cable manufacturer. The number of spot welds shall be equal to the number of armor wires. A plan identifying how the cable and conductors will be protected from the welding activity shall be required prior to performing this work.
8. A power pole installed at the POE to which the Site Development Contractor has attached certain equipment shown in the Contract Drawings.

F. General

Not used

1.02 REFERENCES

A. Standards References

The latest revisions of the following standards and specifications form a part of this Specification, except as indicated otherwise in the body of this specification. In the event of conflict between applicable standards, the governing standard shall be the one that requires the highest quality of work and materials and provides the highest degree of safety to personnel.

IEEE Std. 400.2-2013	Very Low Frequency (VLF) testing (both VLF Acceptance Testing and Tan Delta Testing)
National Electric Energy Testing, Research & Applications Center Georgia Tech College of Engineering, Archive, Chapter 5 TDR	TDR testing of the Submarine Cable as part of Commissioning
NECA/FOA 301	Installing and Testing Fiber Optics
IEC-	Fiber Optic Installation and Termination

61300-3-35.	Testing/Examination
Test multimode cables using TIA-526-14, and single-mode cables, using TIA-526-7	Total Fiber Optic Loss test
TIA-568	Splice Performance
ASTM A123 – Latest Edition	Zinc Coating on Iron and Steel Product
ASTM A153 – Latest Edition	Zinc Coating on Iron and Steel Hardware
ASTM D 1248 – Latest Edition	Specifications for Polyethylene Plastics Molding and Extrusion Materials
ICEA Publication T-32-645 Latest Edition	Guide for Establishing Compatibility of Sealed Conductor Filler Compounds with Conducting Stress Control Materials
IEC 60011-1	Insulation Coordination – Part 1: Definitions, Principles and Rules
IEC 60050	International Electrotechnical Vocabulary
IEC 60060-1	High-voltage test techniques – Part 1: General definitions and test requirements
ICE 60229	Test on Cable Over-sheaths
IEC 60230	Impulse Tests on Cables and Accessories
IEC 60811	Common Test Methods for Insulating and Sheathing Materials of Electric Cables
IEC 60815	Guide for the Selection of Insulators in Respect to Polluted Conditions
IEC60853	Calculation of the Cyclic and Emergency Current Ratings of Cables
IEC 60885-2	Electrical test method for electric cables –Part 2 Partial discharge tests
IEC 60885-3	Electrical test method for electric cables – Part 3 Test methods for partial discharge measurements for lengths of extruded power cables
IEC 63026	Submarine Power Cables with extruded insulation and their accessories for rated voltages from 6 kV (Um = 7.2 kV) up to 60 kV (Um = 72.5 kV) – Testing methods and requirements
IEEE 48 – Latest Edition	Standard Test Procedures and Requirements for High Voltage Alternating Current Cable Terminations
IEEE 404 – Latest Edition	Standard for Cable Joints for Use with Extruded Dielectric Cable Rated 5000 Volts through

	138,000 Volts and Cable Joints for Use with Laminated Dielectric Cable Rated 2500 Volts through 500,000 Volts
IEEE 442 – Latest Edition	Guide for Soil Thermal Resistivity Measurement
IEEE C2 – Latest Edition	National Electric Safety Code as adopted by the State of Washington
ISO 9001 – Latest Edition	Quality Systems – Model for Quality Assurance in Design, Development, Production, Installation and Servicing
ISO 14000 – Latest Edition	Environmental Management Systems
SSPC-SP 6 – 2006	Joint Surface Preparation Standard Commercial Blast Cleaning NACE No. 3
NFPA 70 – 2020	National Electric Code as adopted by the State of Washington and the City of Everett

B. Submarine Cable Manufacturer References

Cable Supplier has provided the DISTRICT with a number of submittals that represent submarine cable manufacturer's recommendations regarding the shipping, handling, installation, and storage of the submarine cable. The CONTRACTOR should become familiar with the contents of these submittals that will govern portions of the installation process. These can be found in the Appendix section of the Contract Documents.

1. Hengtong Production Schedule
2. Shop Drawings and Product Data
3. Factory Inspections and Test Plans
4. Commissioning Plan
5. Operations and Maintenance
6. Spare Parts
7. Installation Instructions
8. Product Delivery, Storage, and Handling
9. Submarine Cable Design and Drawings
10. Safety Data Sheets
11. Closeout Submittals

C. Site Development References (Contract Drawings)

1. HDD Conduit data
2. Vault Design data

D. Permitting Requirement References (These can be found in the Appendix section of the Contract Documents.)

1. City of Everett
2. Snohomish County
3. Washington State Department of Fish and Wildlife
4. Washington State Department of Natural Resources
5. US Army Corps of Engineers

PART 2 – PRODUCTS

2.01 SUBMARINE CABLE SYSTEM

A. Description of DISTRICT-Furnished Cable

1. The submarine cable shall be a 3-phase cable (with separate enclosed neutral and Fiber Optic) with a common overall armor. The phase conductor insulation shall be unfilled Cross-linked Polyethylene (XLPE).
2. Each cable phase shall include a sealed metallic moisture barrier applied directly over the extruded insulation shield.
3. The cable shall be delivered in one continuous length for the entire submarine crossing, plus additional length as spare for future repairs.
4. The cable system shall be designed for:
    - Normal max conductor temp: 90 ºC
    - Emergency temp: 105 ºC
    - Short circuit temp: 250 ºC for specified duration

B. Cable System Technical Requirements

1. Grounding and Armor Isolation

    a. Equipment grounding shall support maximum fault currents and be no smaller than #2 AWG copper or equivalent.
    b. Grounding connections must be insulated to at least 600 Volts.
    c. Armor ends shall be stripped and spot welded to insulated termination plates per manufacturer recommendations.
    d. Armor shall be electrically isolated from sheaths and grounding conductors at shore-end transitions.
    e. If armor is terminated before vault entry, it shall be transitioned to a #2 AWG cathodic protection cable via an RTV-potted ring, with 600V insulation rating.
    f. The cathodic protection cable shall be routed to the nearest vault ground after connecting to the Dairyland PRC.

2. Insulated Armor Wire Termination Plate or Rings

    a. Supplied by the DISTRICT.
    b. Shall be installed by CONTRACTOR at both ends of the submarine cable.

c. Corrosion-resistant, sealed against saltwater, and electrically insulated.
d. Cathodic protection grounding leads shall be installed by CONTRACTOR from the armor clamps shall connect to both the cathodic protection and the vault/electrical box ground.

3. Split Pipe Cable Protectors (As Required)

a. Approximately 200 linear feet shall be furnished and installed if seabed conditions require suspension protection.
b. Additional footage over 200 feet shall be negotiated via change order.
c. Material shall be galvanically and chemically compatible with the environment and have:
    i. High crush resistance
    ii. 40-year minimum service life
d. Cast or ductile iron (minimum wall thickness 6 mm) or approved equal (e.g., Wheatland, Protectoshell, Blue Ocean)
e. Installation must not damage armor wire insulation.

2.02 SPARE MATERIALS, TOOLS, AND EQUIPMENT

A. Use of Spare Cable, Sea Splices, and Repair Materials

1. If damage occurs after delivery and acceptance, the CONTRACTOR may use the DISTRICT's spare materials.
2. CONTRACTOR must replace all used materials and perform repairs at no additional cost.

B. Spare and Surplus Cable Storage

1. Spare cable and any surplus not used shall be sealed and returned to a DISTRICT-identified location.
2. Cable reels shall be clearly labeled and stored per DISTRICT direction.

C. Tools and Equipment Transfer to DISTRICT

1. All non-standard and reusable cable installation tools (dies, presses, etc.) used by the CONTRACTOR or subcontractors shall become property of the DISTRICT.
2. Tools must be cleaned, packed in lockable storage labeled "SUBMARINE CABLE REPAIR TOOLS & MATERIALS", and delivered to the DISTRICT's designated facility.
3. Also includes marine vendor-supplied tools or materials.
4. Excludes commonly available tools (hammers, screwdrivers, etc.).

2.03 DELIVERY, STORAGE, AND HANDLING (Refer to Section 01 60 00)

2.04 WARRANTY

A. Submarine Cable Contractor Warranty

1. General Warranty:
    - Two-year warranty on all goods and services from date of final acceptance
2. Submarine Cable Repairs by CONTRACTOR:
    - Five-year warranty for repairs due to CONTRACTOR-caused damage
3. Manufacturer Warranty:
    - Longer warranties from suppliers shall be passed to the DISTRICT (labor limited to two years)

2.05 MAINTENANCE MANUALS

A. Submittal Requirements

1. Comprehensive electronic maintenance manual shall be provided.
2. Manuals shall include:
    - Table of Contents
    - Index
    - System-based chapters (Submarine Cable, Split Pipe, Hat Island, Port of Everett, etc.)
    - Documentation of damaged/repaired equipment
    - ROV footage and any pictures as specified

B. Test Data

1. Include historic electrical and fiber optic test data for future maintenance reference.

PART 3 – EXECUTION

3.01 INSTALLATION REQUIREMENTS

A. General

Cable system installation shall include all labor, equipment, material, and work necessary to install the 12.47 kV cable systems from the connection to the Port of Everett (POE) Power Splice Vault 200 Amp load-break elbow, to the Hat Island Power Splice Vault 200 Amp load-break elbow. The fully functioning system includes grounding, cathodic protection, and electrical acceptance testing.

Installation method shall be surface lay, between two landings, with conduit installations (pulls) through the near shore environment, and into splice vaults. Conduits and splice vaults shall be in place (installed by others under sperate contract) by the time Work begins.

B. Environmental Requirements (Refer to Section 01 57 19)

1. Ship, Vessel, Vehicle, Equipment Fueling, and Servicing
   a. Vehicles, vessels, ships, and equipment shall be serviced and used in a manner that no contaminants will enter the water or ground.
   b. Fueling and servicing waste shall be disposed of in a manner approved by local government authorities.
   c. Ships, vessels, vehicles, and equipment shall not leak oil, fuel or other contaminants.
   d. Oil Spill Contingency and Cleanup Plan

      The Submarine Cable CONTRACTOR shall have an oil spill contingency plan, per Environmental Protection Agency regulations titled, "Discharge of Oil" 40 CFR 112 and shall submit this to the DISTRICT for acceptance before commencing any installation work at the site.
2. Required Permits

   Prior to installation, the DISTRICT will have all the permits identified in the Appendix of the Contract Documents. All CONTRACTOR required permits and services not obtained by the DISTRICT but required to complete the project, including harbor clearances, formal agreements, etc. shall be obtained by the CONTRACTOR in advance of the cable laying date.
3. Location and Safety of Existing Cables, Anomalies, and Features

   The CONTRACTOR shall electronically mark on AutoCAD files the route of any existing cables or underwater anomalies or features, at all points where there is less than 50 feet of separation between any such features and the new submarine cable. GPS survey readings shall be used to identify the land portions and the submerged sections of cable.

   The CONTRACTOR, at no cost to the DISTRICT, shall repair any damage to existing features or facilities, including but not limited to cables, bull rails, marina floats, dock fenders, etc. caused by the CONTRACTOR, to the DISTRICt's satisfaction. Any required repairs shall be illustrated on the As-Builts Records.

C. Schedule of Work (Refer to Section 01 11 00)
   1. For purposes of the DISTRICT's requirements, the CONTRACTOR may work [24 hours per day] during cable lay operations. Local permit conditions may be more restrictive than other activities.
   2. All Work schedules must comply with the permit conditions, within the Appendix and in accordance with Section 01 11 00.

D. Interference with Navigation and Adjacent Activities (Refer to Section 01 31 13)
   1. Possession Sound is an active navigation corridor used by commercial vessels, military vessels, and tribal fishing activities. Military and commercial vessel traffic, including tribal use shall have precedence over the CONTRACTOR's activities and will require the CONTRACTOR to stop, move, adjust, and/or slow down to accommodate these activities.
   2. Coordination with the Port of Everett, the Hat Island Marina, the Tulalip Tribes, the US Navy, and the US Coast Guard Vessel Traffic Control Office will be required as their respective operations will be ongoing during the cable installation activities.

3. While conducting submarine cable installation operations, the CONTRACTOR shall anticipate and make allowance for inherent delays, including but not limited to commercial vessel traffic and tribal use.
4. Any damage to the CONTRACTOR's equipment in navigation lanes due to the CONTRACTOR's failure to move to accommodate military or commercial vessel traffic and tribal fishing activities shall be at the CONTRACTOR's sole risk and expense.

E. Security Concerns (Refer to Section 01 35 53)

The CONTRACTOR shall comply with all applicable Port of Everett and U.S. Coast Guard (USCG) regulations, including Maritime Security (MARSEC). All costs associated with implementation of required security measures will be considered incidental to the Contract. Refer Specification Section 01 35 53 for additional requirements.

1. Due to heightened security concerns, the CONTRACTOR shall give notice and receive required approval from the DISTRICT's Project Lead prior to berthing at any location along adjacent docks for any purpose.
2. The CONTRACTOR shall notify USCG as required, to coordinate and comply with regulations for operating within Possession Sound.
3. The CONTRACTOR shall notify POE as required, to coordinate and comply with rules and regulations associated with their facilities and operations.
4. CONTRACTOR personnel that do not have TWIC identity cards will not be allowed on POE docks or terminals. Application for and training associated with TWIC identity cards are incidental to the CONTRACTOR's mobilization expense. (Refer to Section 01 31 13.)

F. Permits

1. Permits and Compliance: The CONTRACTOR shall be responsible to adhere and conform to all applicable provisions, conditions, and requirements of the project permits/authorizations included in the Appendix section of the Contract Documents. All the permits may not be available at the time of solicitation. CONTRACTOR is only responsible for those included at the time of this solicitation. Additional costs associated with permit requirement obtained after this solicitation shall addressed with the Change Order process outlined in the Contract Documents, further described in the General Conditions, 00 72 00.
    a. CONTRACTOR shall comply with all the permits/authorizations located in the Appendix of the Contract Documents.
    b. Any conflicts between the Contract Specifications and issued permits shall be brought to the attention of the DISTRICT. Nothing shall be deemed to authorize violation of the issued permits.
    c. The CONTRACTOR's attention is directed to the permit approval conditions. The inclusion or lack of inclusion in this section is not to be considered a measure of the permit approval condition's importance or likely enforcement. The CONTRACTOR is required to meet all permit approval conditions. The CONTRACTOR shall pay particular attention to the conditions of issued regulations and authorizations requiring minimizing turbidity creation during activities of laying cable, and associated activities, on the seafloor.

G. Access To Contractor's Equipment

1. The CONTRACTOR shall grant access to its cable laying vessel, crane, barges, tugs, offloading facility, water management, lay down areas, and all other equipment mobilized for the project for coordination, field observations, monitoring, or inspection purposes, to the DISTRICT or to any DISTRICT-designated representative.
2. If the CONTRACTOR's equipment is not accessible from the dock, the CONTRACTOR shall provide access to and from for designated DISTRICT personnel upon request.

H. Other Submarine Cable Installation Requirements

The CONTRACTOR shall always have on site, sufficient staff and equipment to adequately handle all phases of the cable installation in conformance with good cable installation practice.

The CONTRACTOR shall ensure that the cable bending radii are above the allowed values throughout the installation. The CONTRACTOR shall also ensure that the maximum pulling tension is not exceeded throughout the installation.

If the submarine cable is damaged while in the CONTRACTOR's custody, during loading, transportation to the installation site or during the installation; the CONTRACTOR shall inform the DISTRICT and repair the cable at no cost to the District. Splicing, if required, shall be performed by experienced and qualified personnel in accordance with the drawings and installation instructions provided by the cable manufacturer and accepted by the DISTRICT. A warranty shall be provided by the CONTRACTOR on both the materials and labor/workmanship for any repairs in accordance to this Section.

I. Sea Floor and Shore Installation

1. Submarine Cable Installation

a. The CONTRACTOR shall be allowed to select a modified final cable route within the allocated corridor and with concurrence from the DISTRICT's Project Lead, and shall determine the necessary cable length which must be within the amount of submarine cable ordered. The results of an existing condition survey report, included in the Appendix, are included in the Contract Documents; however, verification of the survey work and data shall be the responsibility of the CONTRACTOR. The CONTRACTOR shall perform any additional surveys it deems necessary, at no additional cost to the DISTRICT.

b. The new cable shall not cross over existing cables. Studies performed for the DISTRICT indicate that there are no existing cables that will be crossed. However, if crossing of an existing cable becomes necessary or one is discovered, then the CONTRACTOR shall construct an acceptable bridge or other acceptable means to isolate and protect both cables, or if the other cable is abandoned assist the DISTRICT in gaining a liability release from the other cable owner prior to abandonment. Additional costs associated with an unforeseen crossing shall be addressed with the Change Order process outlined in the General Conditions in the Contract Documents.

c. The CONTRACTOR shall perform the submarine cable laying operation with due regard to variations in weather conditions, tides, water currents, bathymetry, minimized

disruption of other marine vessel traffic, avoidance of underwater hazards and accurate positioning of the laying vessel and cable touchdown on the sea bottom.

d. An integrated marine survey navigation computer system with differential GPS receiver shall be used to accurately determine, display, and record the positions of the cable, cable laying vessel, support equipment, cable corridor boundaries, existing cables, proposed cable routes and bathymetry throughout the cable laying program. A backup system shall be provided unless it can be demonstrated that the primary survey system has a zero probability of failure or that it has sufficient redundancy built into the critical circuits.

e. For depths between 0-100 feet, as it relates to MLLW, the submarine cable shall be laid with a 3D accuracy of less than ±3.28 feet.

f. For depths between 100-465 feet, as it relates to MLLW, the submarine cable shall be laid with a 3D accuracy of less than ±10-feet.

g. All personnel in critical operating positions during the laying operations shall be in constant communication during the cable laying operation. Those persons in critical positions during the laying operation shall speak English as commonly used in North America. Translators shall not be allowed for those in critical positions during the laying operation.

h. While the cable is being laid, or within 30 calendar days after the cable is laid, the complete length of underwater cable shall be inspected with an ROV to make certain there are no suspensions longer than seven feet and that there are no suspensions on sharp rocks. If these conditions exist the cable shall be moved to correct the problem, or an alternative form of mitigating the concern (split pipe, etc.) employed that is acceptable to the DISTRICT.

i. The entire underwater inspection, including inspections after removal of suspensions, shall be recorded on an electronic video format such as a DVD format. These DVD's shall become the property of the DISTRICT upon completion of the project.

j. Actual cable laying tensions and angle shall be continuously monitored and periodically recorded. It shall be compared against the calculated values and minimum and maximum limits. The measurements shall be electronically referenced to UTM coordinates and water depth. The measured cable tension shall be corrected for the dynamic tension variations induced by the waves and for the influence from drag caused by sea current and the laying vessel's velocity. The records and documentation with comparisons will be provided to the DISTRICT after installation of the submarine cable. Any events where excessive tension occurred will be noted and reported to the DISTRICT immediately.

k. CONTRACTOR shall supply continuous continuity for power and fiber during cable lay. Alarm should alert operators should continuity be lost during lay.

l. Under no circumstances shall unsupported spans exceed the agreed maximum allowable unsupported span length, considering cable characteristics, cable tension and supplemental measurements or estimates of tidal current speeds.

m. Log sheets, diaries and records of the laying operations shall be kept on a daily basis and forwarded each day to the DISTRICT.

n. A complete formalized record of the cable laying operation shall be provided to the DISTRICT at the completion of the cable laying activities. It shall be comprised of a laying report identifying all aspects of the work. As-Built Drawings shall indicate cable locations with an accuracy of +/- 1.5 meters above water and as achievable with a modern USBL positioning system underwater.

o. The cable laying will be witnessed by the DISTRICT and/or its representatives.

2. Split Pipe Cable Protectors associated with Suspensions (as required)

Split pipe articulated mechanical cable protectors shall be installed if the cables cannot be laid on the bottom and are unsupported for more than 7-feet.

If protectors are required in deep water, not accessible by divers, the protectors shall be of a type that can be attached to the cable as it is laid. This may be necessary if there are areas of underwater hazards identified in the CONTRACTOR's marine survey. Other methods of cable protection may be proposed for consideration by the DISTRICT.

K. Land Installation

Land installations shall include, but are not limited to the following:

1. Pulling cable into the horizontally directionally drilled HDPE conduit, and into the vault. (75-feet minimum beyond the far wall of the splice vault on both ends).
2. Stripping cable to reveal its individual components. Entire length of the cable beyond armor termination plate (approximately 90-feet).
3. Racking of cables extra length inside the vault.
4. Installation and landing of the DISTRICT-supplied elbows to the existing junction boxes (installed by others).
5. Installation of conduit plugs or sealant to prevent water entry into the 10" HDPE conduit at depth.
6. Installation of conduit plugs or sealant to prevent water entry into the 10" HDPE conduit at the splice vaults.
7. Installation of termination rings.
8. Welding of cable armor to the termination plates or rings.
9. Installation of cathodic protection equipment.
10. Coordination with DISTRICT to install the vault lid section (DISTRICT-supplied).

L. Safety and Restriction (Refer to 01 35 29)

There may be energized equipment in the work areas. The CONTRACTOR shall provide a qualified safety watcher in accordance with normal "Safe Working Practices," at all times when working around energized equipment.

M. Cable Pulling

1. The CONTRACTOR shall perform all calculations necessary to assure that maximum allowable tensions and sidewall pressures are not exceeded during the pulling of cable into conduit. The cable shall be pulled by an appropriately designed and installed pulling eye or Kellum Grip, supplemented by the "bond pulling" method and caterpillar traction pullers or motor-driven rollers, if necessary. The pulling method should conform to the requirements and recommendations of the submarine cable manufacturer.
2. A recording dynamometer shall be used to measure pulling tensions on the pulling attachment during cable installation in conduit. A continuous record of the actual pulling tensions shall be provided. The pulling will be done in a single pull. This information will be presented to the DISTRICT and any excessive pulling tensions shall be identified in the documentation.
3. Cable rollers, Bull Wheels, etc., shall be used at suitable locations and intervals to control cable sidewall pressures, tensions, and bending radius, and protect against scrapping, nicks, or cuts, during the cable pulling operation. Sufficient observers (including divers) shall be stationed along the pulling route to make certain mitigation techniques are in place and the cable is protected against damage.
4. Following the cable pulling operation, the rollers and other temporary installation equipment shall be removed and the work area cleaned.

N. Cable Splices Joints and Terminations

1. Adequate temporary shelters shall be provided as necessary during installation of any cable splices, joints, elbows, and terminations; during testing to protect against rain, dust, moisture, contaminants, etc.
2. Installation of the splices, joints, elbows, and terminations shall be by experienced, qualified personnel, in accordance with the Drawings and installation instructions provided by the manufacturer.
3. The work shall include the installation of armor terminating devices and connections to (and furnishing of) the cathodic protection system.
4. The work shall also include the testing and careful handling of the fiber optic ends. Termination of the fiberoptic is not included in this Contract.

O. Cathodic Protection

1. The cathodic protection system shall be installed as shown on the approved Drawings.
2. Welded connection of the insulated armor wire rings so that AC grounding and DC armor wire voltage isolation are properly installed.
3. Supply and install the remaining components in the Nema 4x boxes, as required for a fully functioning cathodic protection system.

3.02 EXAMINATION

A. Site Verification of Conditions

The CONTRACTOR shall inspect and verify site conditions to CONTRACTOR's own satisfaction. This includes both Hat Island and POE, including the clearances for work and equipment access and the methods of both pulling and attaching the cable to splice vaults.

This further includes bathymetry data included in the Appendix.

3.03 PREPARATION FOR EXECUTION OF WORK

A. Work Plan Concepts

1. The pre-construction submittals by the CONTRACTOR shall include a detailed, written project Work Plan. The project Work Plan shall include, but not be limited to the following:

   a. Witnessing Submarine Cable Electrical Testing at time of delivery to the DISTRICT.

   b. Transportation of the Submarine Cable, and DISTRICT-furnished equipment to the cable laying vessel.

   c. Layout of lay-down (or staging) for various equipment.

   d. Split pipe(s) staging.

   e. Storage of the Spare Cable and Reel.

   f. Details of long-term storage (if required).

   g. Sequence and details of cable laying.

   h. Contingency Plan in case of a storm delay.

   i. Cable pulling into splice vaults.

   j. Electrical and mechanical termination of the submarine cable.

   k. Electrical Acceptance Testing of the Submarine Cable System.

   l. Contingency Plan, outlining the CONTRACTOR's response should the installed cable not pass the acceptance tests. Details to include:

      i. CONTRACTOR's overall approach.

      ii. Recognition that the cable lay vessel, key personnel and other resources should remain until testing is satisfactory.

   m. Installation of Split Pipe (if needed due to suspensions).

   n. Sealing of conduit between splice vaults and HDD HDPE conduit (both landings).

   o. Water management disposal.

   p. Post-construction clean-up.

   q. Surface restoration and vault lid setting.

   r. Fulfillment of required reports, permit documents and construction records.

   s. Transportation of any specified parts, tools, or equipment to DISTRICT Facilities.

2. The project Work Plan shall be reviewed and approved by the DISTRICT prior to starting any Work. Copies of the Work Plan and all approved submittals shall be kept on-site (or the installation vessel) and available, for DISTRICT immediate reference.
3. The CONTRACTOR will familiarize its employees with the Work Plan contents and its location at the construction work site.
4. A contingency plan shall be presented to DISTRICT in case adverse weather or sea states interfere with the CONTRACTOR's methods during the scheduled cable laying installation process.
5. The CONTRACTOR shall not demobilize the cable laying vessel until after all electrical tests and commissioning have been performed and the cable has been accepted by DISTRICT.

B. Debris Removal and Avoidance

1. Prior to, or concurrent with the laying the submarine cable and associated equipment, it is expected that sunken pilings, anchors, chains, abandoned crab pots, etc. will be encountered.
2. The CONTRACTOR shall investigate the route and either remove debris encountered or adjust the route to avoid suspensions and hazards. Prior to executing any debris removal, CONTRACTOR shall consult with the DISTRICT for consideration of cost implications.
3. Debris removed along the route shall be photographed.
4. Any unforeseen debris removal shall be addressed with the Change Order process outlined in the General Conditions, in the Contract Documents.

C. Site Tests

1. Field Testing: Perform field testing and visual and mechanical inspection to insure that all materials used in the specified project are in good working condition and that each part of the system is installed correctly.
2. Completed Cable System Electrical Test
3. Each phase of the completely installed cable system shall receive a 1.7 per unit 60 cycle test by the application of system phase-to-phase voltage between the conductor and the metallic sheath as per IEC 60840.
4. A very low frequency (VLF) test, in accordance with IEEE Std. 400.2-2013 shall also be performed and passed.
5. A Tan Delta test shall also be performed to provide an ongoing baseline for future maintenance examinations.
6. A TDR test shall be performed to identify any anomalies within each of the phase wires of the Submarine cable.
7. Complete Cable System Fiber Optic Test (to be expanded, by DISTRICT requirements and Section 1.01 A References: National Electric Energy Testing, Research & Applications Center Georgia Tech College of Engineering, Archive, Chapter 5 TDR; NECA/FOA 301;

IEC-61300-3-35; Test multimode cables using TIA-526-14, and single-mode cables using TIA-526-7; and TIA-568.

8. Armor Wire

   a. After installation of the Submarine portion of the cable and prior to splicing to the land sections of cable, the resistance of the armor wire to ground will be checked. This test may be conducted using a 500 volt Megger connected between each successive armor wire and a 3 foot ground rod driven into the vault/electric box grounding system. While there is no pass/fail quantity for this test, the resistance of each armor wire to seawater shall be recorded and the test results shall be provided within 14 days to the DISTRICT and before the cathodic protection system is Substantially Complete.

   b. After completion of the cable installation, the cathodic protection system shall be tested to determine that it is installed correctly and that it is performing its intended function and will provide corrosion protection for the cable armor.

9. Cable Voltage Soaking and Test

   a. The submarine cable shall be energized with DISTRICT primary power and allowed to "soak" for 24 hours, so as to allow electrically field caused mechanical forces on the insulation and cable to stabilize prior to the submarine cable being put in service and accepted by DISTRICT.

   b. A final component of this phase of the testing will be to perform a thermal scan of all components after load to Hat Island is placed on the cable, including the load-break elbows within the vaults to ensure that the temperatures are consistent with the nominal temperature within the primary electrical system.

END OF SECTION

Attachment (2) to Exhibit B
Operation and Maintenance

Operations & Maintenance Plan

Hat Island Subsea Cable – Port of Everett to Hat Island

60-Year Operational Horizon (2026-2086)

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1. Purpose of This Plan

This Operations & Maintenance (O&M) Plan outlines the procedures, schedules, responsibilities, and performance standards required to ensure safe, reliable, and environmentally compliant operation of a subsea power cable located in Port Gardner, Puget Sound over a 60-year service life.

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2. Project Overview

- **Asset:** Subsea power transmission cable (on-bottom installation)
- **Location:** Port Gardner, Puget Sound, Washington State
- **Operational Lifespan:** 60 years
- **Installation approach:** Cable will be laid directly on the seafloor (not proactively trenched or buried). Due to its design weight and armoring, it is expected to remain in place after installation and will only be displaced by substantial external forces such as vessel anchors, heavy fishing gear, or extreme seabed disturbances.
- **Self-burial expectation:** The cable is expected to progressively self-bury over time in areas with mobile or silty substrates (which comprise the majority of the route). Self-burial rates will vary by location and sediment dynamics; some hard-bottom or coarse-sediment segments may remain exposed and require occasional inspection.
- **Cable Type:** 3-phase, armored cable; rated 15kV; contains neutral and fiberoptic.
- **Landing Sites:** Port of Everett and Hat Island
- **Regulatory Authorities:** USACE, WDFW, WDNR, USCG, WA DOE, local jurisdictions, and relevant federal agencies
- **Primary Risks:** Vessel anchoring and dragging, fishing interactions, localized exposure in coarse substrate areas, corrosion, insulation degradation, water ingress, thermal loading, seismic events, and benthic habitat disturbance.

---

3. Roles & Responsibilities

3.1 Operator

- Overall cable system oversight
- Coordination with regulatory agencies
- Maintaining monitoring, inspection, and reporting records

3.2 Marine Maintenance Contractor

- Performs subsea inspections, surveys, and repairs
- Maintains marine asset readiness (vessels, ROVs, divers)

3.3 Electrical Utility/Technical Team

- Monitors electrical performance (
- Periodic thermal scans of medium voltage terminations
- Conducts power quality assessments
- Analyzes fault events and trending
- Monitoring of the cathodic protection system
- NETA medium voltage and low voltage (grounding/cathodic protection wiring) visual/mechanical inspections; things to do after any major faults or lightning strikes near the cable that do not produce a fault in the cable
- Testing system protection devices protecting the submarine cable
- NETA fiber-optic inspections and testing

3.4 Environmental Compliance Team

- Oversees environmental monitoring
- Ensures compliance with permits and habitat protections
- Manages spill prevention and response procedures

---

4. Operations Program

4.1 System Monitoring

Continuous Monitoring (24/7): - Load and voltage monitoring - Cable temperature and thermal loading - Power quality (harmonics, protection relay status) - SCADA alarms for insulation resistance, fault detection, and thermal excursion

Periodic Monitoring: - Monthly: Review SCADA logs, trend analysis - Quarterly: Electrical system performance report

4.2 Communication & Notification Procedures

- Immediate notification of any system fault or outage
- Communication protocols with utilities, Coast Guard, and emergency partners
- Notification to fisheries and maritime operators during maintenance work windows

---

5. Inspection & Maintenance Schedule

5.1 Routine Visual & Condition Surveys

Frequency: ROV footage during cable touchdown and side scan sonar investigation within the first 5-years of operations to document initial siting, self-burial progression, and stability; every 10 years thereafter, adjusted based on observation and data collected in prior deployments.

Coordination With Tribes for Side Scan Sonar Monitoring: The District will coordinate with a local tribe, who will conduct periodic side-scan sonar surveys along the cable alignment primarily to detect entangled shrimp and crab gear. These datasets will also be used by the District to: - Confirm that self-burial has occurred in silty substrate areas. - Verify that the cable has remained in its installed position and has not migrated. Evidence of scouring can be identified at this time as well.

While the cable is wrapped with armor and has a specific gravity heavier than water, it will settle into its new resting place and effectively resist movement from any natural forces that might occur along the route. Movement of the cable, after the completion of its initial installation, will require a significant external force (i.e. commercial fishing, vessel anchor, etc.).

If scour or any significant sediment displacement is identified, the District will notify the authorities with jurisdiction listed in Section-2.

5.2 Shore Landing Inspections

Frequency: Annually – Landing site facilities (vault condition, conduits, etc.) on both sides

5.3 Electrical Testing & Diagnostics

Frequency: Every 3–5 years - Partial discharge testing - Insulation resistance (IR) trend review - Sheath and bonding system testing - Thermographic analysis at onshore terminals

5.4 Integrity Surveys

Frequency: Every 10 years or as required – Tabletop geophysical route survey - Sediment mobility analysis - Seismic risk and slope stability updates

6. Maintenance & Repair Protocols

6.1 Routine Maintenance

- Armor repair for localized damage
- Debris removal from cable route – if required

6.2 Major Repair Activities

Trigger Events: - Critical fault detected - Anchoring or fishing gear strike - Insulation failure or water ingress

Procedures:

1. Isolate and de-energize cable
2. Deploy vessel and ROV for localization
3. Retrieve damaged section (grapnel or ROV-assisted recovery)
4. Replace or splice in new section
5. Re-lay cable on the sea floor.
6. Commissioning tests prior to reenergization

6.3 Emergency Response

- Notifying Coast Guard, WA DNR and maritime users of hazard zones
- Environmental protection and containment (if applicable)
- Incident reporting within regulatory timelines

7. Environmental Compliance & Monitoring

7.1 Pre-Maintenance Notifications

- Compliance with ESA, MSA, and local habitat protections
- Notification to tribes, fisheries groups, and resource agencies

7.2 Water Quality and Turbidity Monitoring

- Required removal and re-laying, or other sediment-disturbing work
- Monitoring for pH, turbidity, dissolved oxygen, visible sheen, and sediment plume dispersal
- Real-time logging and reporting

7.3 Habitat & Species Protections

- Consult with staff environmental specialist prior to any work in or around the water

- Avoid in-water work during critical fish windows unless exempted
- Avoid eelgrass and sensitive habitats during surveys when feasible
- Adhere to marine mammal shutdown zones during noisy operations

---

8. Asset Management & Lifecycle Planning

8.1 Recordkeeping

- As-built drawings and route charts
- Inspection logs
- SCADA data archives
- Repair and maintenance history

8.2 Predictive Maintenance

- Trend analysis for partial discharge and IR
- Risk scoring of cable segments
- Forecasting replacement intervals for joints, hang-offs, and protection structures

8.3 Mid-Life Refurbishment (Years 30-40)

- Work with WA DNR on renewing lease at 30-years
- Shore termination assessment and replacement as required
- Cable joint assessment and replacement as required
- Protection at high-risk segments if needed

---

9. Decommissioning Planning (End-of-Life Considerations)

- Review regulatory requirements for full or partial removal
- Evaluate environmental risks/benefits of leaving cable in situ
- Develop de-energization and isolation plan
- Engage resource agencies early (3–5 years before decommissioning)

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10. Appendices

Appendix A – Emergency Contacts

Appendix B – Maintenance Equipment List

Appendix C – Environmental Monitoring Protocol Templates

Appendix A – Emergency Contacts

	Name	Title	Role	Office	Cell	email
1	Schneider, Eric	Principal Engineer	Project Lead	425-783-8624	425-293-7218	easchneider@snopud.com
2	Dahlbeck, J.C.	Project Manager III	Project Lead	425-783-4489	425-367-2948	JCDahlbeck@SNOPUD.com
3	Spahr, Jessica	Program Manager IV	Permitting	425-783-8132	425-758-7360	jlscpahr@snopud.com
4	Murphy, Colleen	Mgr Environmental Affairs	Environmental	425-783-5504	425-275-6748	cmmurphy@snopud.com
5	Carstens, Amy	Sr Mgr Trans & Dist Sys Op & Eng	Management Sponsor	425-783-4201	425-565-0961	acarstens@snopud.com
6	Schellberg, Zeke	Principal Engineer	Standards	425-783-4313	425-583-9535	enschellberg@snopud.com
7	Barnes, Maureen	Mgr Real Estate Services	Real Estate	425-783-4373	425-248-8634	mlbarnes@snopud.com
8	Kiss, Paul	Sr Operations Superintendent	Operations Planning	425-783-4433	425-218-9243	pjkiss@snopud.com
9	Ruiz, Greg	Line Construction Gen Foreman	Operations Execution	425-783-4375	425-344-2449	Jgruiz@snopud.com

Appendix B – Maintenance Equipment List

Materials (aside from stock items)

1. (Qty-2500 ft) spare subsea cable (Operations Center)
2. (Qty-3) spare termination elbows (Operations Center)
3. (Qty-2) spare underwater splice kits (Operations Center)

Specialized Equipment

1. Cable testing equipment (Operations Center)
2. Fiber-optic testing equipment (Operations Center)
3. Thermal testing equipment (Operations Center)

Appendix C
Environmental Monitoring Protocol Templates

Hat Island Cable Replacement Project

WATER QUALITY MONITORING PLAN

Submitted by:

Public Utility District No. 1 of Snohomish County

October 28, 2025

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1.0 INTRODUCTION

Snohomish County PUD (Snohomish PUD) provides electrical service to Hat (Gedney) Island, near Everett, WA, via an existing 3-phase submarine power distribution cable installed in 1974. The 12kV electrical distribution cable extends from Mission Beach (west of Marysville, WA on the Tulalip reservation) to Hat Island. Snohomish PUD provides service to approximately 250 residential and business customers on Hat Island, and its population fluctuates seasonally. The island's electric service also powers its drinking water system.

The existing submarine cable has reached the end of its serviceable life and is at risk of failure. To avoid a potential emergency which would isolate the residents of Hat Island from electric service, Snohomish PUD plans to install a new 3-phase electric submarine cable along a new subsea route, from the Hat Island Marina to the Port of Everett, a distance of approximately 32,000 feet. To continue reliable service to District customers, the existing cable will remain energized while the new line is installed. The new cable will be installed via horizontal directional drilling (HDD), which would allow the cable conduit to run subsurface beneath the sensitive nearshore and shoreline environment on both the mainland and the cable's Hat Island connection. The HDD would exit the sea floor below the ordinary high water mark of the Port of Everett and Hat Island, then will be directly laid on the sea floor between those points.

The purpose of this Water Quality Monitoring Plan is to support Snohomish PUD's applications for aquatic resource permits and authorizations, including a 401 Water Quality Certification from the Washington Department of Ecology (Ecology).

Any changes to this Plan must be approved by Ecology prior to implementation. Approval is not necessary for minor adjustments to BMPs and/or procedures that are needed as the work is being done.

Table 1 outlines all in-water activities associated with the project and proposed monitoring for each. Details are presented in following sections.

Table 1. Proposed Activities and Monitoring

Activity	Turbidity Monitoring Proposed		pH Monitoring Proposed	Oil Sheen (Visual Monitoring)
	Visual	Physical		
HDD Exit/Reaming	Yes	Yes[3]	Yes	Yes[1]
Frac-out	No	Yes	Yes	Yes[1]
Cable Lay	Yes[2]	No	No	Yes[1]
Cable Operation	No	No	NA	NA

Footnotes:
1. For vessels and construction equipment
2. With ROV observation of cable touchdown
3. If visual monitoring observations indicate potential exceedance.

2.0 Potential Project Effects on Water Quality

2.1 Increase in Turbidity During HDD Activities and Cable Deployment

Section 3 below describes HDD and cable deployment procedures. There is a small possibility of increased turbidity during HDD activities due to a "frac-out," where drilling mud or fluid escapes into the environment as a result of a spill, tunnel collapse, or rupture to the surface. The HDD Plan Narrative contains procedures and practices to minimize potential for a frac-out to occur. HDD activities will be carefully monitored and the contingency plan in the HDD Plan will be implemented if a frac-out is detected.

Geophysical review of the sea floor indicated a rocky cobbled seabed with areas of fine-grained marine sediment. As a result, a very small increase in turbidity may occur when the cable contacts the sea floor. Visual monitoring is proposed unless there is a frac-out or observations indicate an exceedance.

2.2 pH Sampling During HDD Activities

In the event of a frac-out water quality sampling for pH will be conducted to ensure compliance with state water quality standards.

2.3 Spills During Installation, Operation and Maintenance

During project construction, a number of vessels, including tugs, a deployment barge, and other workboats will be employed. These vessels contain fuel, hydraulic fluid, and other potentially hazardous materials. All marine construction and maintenance contractors will be required to employ measures to avoid any release of these materials to surface water, and maintain a spill response plan in the event a release does occur.

3.0 IN-WATER AND NEAR-WATER ACTIVITIES

3.1 Horizontal Directional Drilling and On-Shore Activities: Hat Island and Port of Everett

On-shore activities consist of the installation of the HDD cable via a 18' by 6' bore pit, plus two electrical vaults (14' by 6' and 20' by 7'), and a trench connecting the cable to the vaults (75' long by 2' wide by 4' deep).

A typical HDD entry site layout includes an equipment staging area plus an excavated sump pit approximately near the entry point. The sump pit allows recovery of the drilling mud coming from the borehole. The mud is picked up by a sump pump and transferred to the solids control unit where the drilled solids are mechanically settled out, allowing the mud to be re-circulated down the hole and used again. Once the trunk cable conduit is placed, the HDD equipment will be removed and only the cable pull and trenching equipment will remain to complete the HDD operations. Demobilization of the HDD operations consists not only of disassembling and removal from the site of all HDD equipment and materials but also site restoration including the following:

- Restoration of site to original grade;
- Replanting and/or new planting of vegetation as needed;
- Repair of any site structures as needed; and
- Removal of any project generated debris.

The Hat Island Subsea Cable Project will include two HDD installations and each installation will have an entry location and an exit location where work will be required. The primary staging area will be at the entry location where the drill rig, soil separation plant, excavator, delivery trucks, vacuum trucks will be on site during various stages of construction. The drilling fluid is composed of naturally occurring bentonite clay and water. The clay is insoluble and made up of small particles that function as a lubricant for the drill head and pipe, a transport for the cuttings being removed from the hole, and as a sealant that fills the annulus space surrounding the drill hole. The drilling mud pressure and volume are monitored during drilling operations to assure there are no leakages due to fractures in the structure of the material being drilled through. If a fracture is present it is possible for drilling mud to escape onto the surface or into the water, commonly known as a "frac-out." While no fractures are expected in this glacially deposited substructure, the driller is always monitoring for a frac-out. By monitoring the pressure and volume, such fractures can be identified as they occur and steps can be taken to eliminate the problem. The driller can stop or slow down the operations to give the mud a chance to seal the frac-out. If that is impractical or doesn't work an alternative route can be taken.

As the drill stem approaches the exit point on the ocean floor, the drilling conditions will be carefully monitored. These conditions determine the time or distance from the exit when a shift from the bentonite drilling fluid to fresh water drilling is achieved. By flushing the drill string with fresh water, the drilling mud is circulated out of the system and a mud free exit is achieved. It must be reiterated that drilling conditions, not a pre-determined distance will be the factor as to what point the change to water will occur. As a rule of thumb, 100 feet is the average distance at which a change to fresh water happens. The driller and surveyor will know when the bottom hole assembly exits the sea floor, not by a loss in pressure, but by watching the console inside the drill cab. When the bottom hole assembly is no longer supported by the soil, the angle of inclination will fall off dramatically thus signaling the bore exit. The marine support crew will be dispatched to dive on the exit and verify the exit point. Once the exit has been verified by the divers, the on-site inspector will be given the true offshore exit coordinate to approve.

Physical monitoring for turbidity if there is a frac-out or observations indicate an exceedance. pH sampling shall be performed in the event of a frac-out.

Additional drilling details are presented in the Horizontal Directional Drilling Plan.

3.2 Cable Deployment

The cable will be laid directly on the sea floor and will span the approximately 32,000 foot distance between the HDD subsea exit points. The subsea cable will not be trenched or attached to the seafloor, thus the process to install the cable will not require ground-disturbing activities. However, cable laying vessels will be required to install the cable, and thus visual monitoring for oil/sheen from the cable installation vessels will be conducted. If any fluids are observed leaking from

vessels or their equipment, work will be stopped and appropriate cleanup measures will be implemented. Water quality is anticipated to meet state water quality standards for turbidity during installation of the cable and therefore only visual monitoring for turbidity is proposed unless observations indicate an exceedance of water quality standards..

Visual monitoring is proposed unless observations indicate an exceedance.

3.3 Cable Operation

During normal operation, the cable will rest on the seabed. No water quality monitoring is proposed.

The anticipated lifetime of the cable is 40-50 years. During this time, repair and maintenance may be performed as needed, and appropriate approvals will be sought as required.

3.4 Cable Removal

At this time, removal is not proposed for the existing cable or the new cable. At the end of its useful life, a removal plan will be developed, and appropriate approvals will be sought as required.

4.0 WATER QUALITY MONITORING METHODS AND BACKGROUND

4.1 Turbidity/Sediment

For estuaries or marine waters, the point of compliance for a temporary area of mixing shall be at a radius of 150 feet from the activity causing the turbidity exceedance. Background sample shall be taken at approximately the same time as the point of compliance sample and outside the area of influence of the activity. This location should be roughly 300-feet from the turbidity source and taken. Frequency of monitoring shall be divided into the categories outlined in Table-2 below:

Table 2. Monitoring Frequency

Activity	Monitoring Frequency (w/out exceedance)	Monitoring Frequency (w/exceedance)
HDD Exit/Reaming	2-Hours	1-Hour[1]
Frac-out	Immediate[4]	1-Hour[2]
Cable Lay	Continuous[3]	Continuous[3]

Footnotes:
1. Until an exceedance is no longer detected/or until WQ standards are met.
2. Until turbidity source is neutralized and WQ standards are met.
3. Visual only with ROV observation of cable touchdown.
4. An immediate response to determine if there is an exceedance.

In support of both HDD operations, background turbidity readings shall be collected at each location prior to starting the HDD operations. This may be accomplished with a small vessel or be collected at depth from a nearby pier. Once established, the background turbidity shall be recorded for use in analysis. New background readings shall occur as close to the time of compliance sampling as possible and be obtained for each sampling effort/deployment.

In the event visual monitoring suggests that turbidity sourced from the project is extending to the

compliance point (150-feet from source), physical monitoring at the compliance point shall be employed with frequency in accordance with Table-2 above. If monitoring indicates an exceedance at the compliance point, then monitoring frequency shall increase in accordance with Table-2. This frequency shall continue until the water quality standard is restored.

While the HDD exit point is on a sloped surface, the 150-foot compliance point radius will result in various depths. Physical monitoring at the compliance point shall occur at 20-foot depth intervals with a variable number of readings at each location.

Inadvertent release will be avoided using methods in the HDD Plan and Inadvertent Return Contingency Plan. If a frac-out or other release of grout material occurs, HDD work will stop and turbidity samples will be collected using a turbidity meter, and pH tested. HDD work will not resume unless and until turbidity is less than or equal to 5 NTU over background turbidity when background turbidity is 50 NTU or less, or when there is more than a 10 percent increase over background turbidity when background turbidity is more than 50 NTU.

If the turbidity samples show exceedance at the 150-foot point of compliance the following steps shall be taken:

1. Stop work immediately and assess the cause of the water quality problem.
2. Take immediate action to stop, contain, and correct the problem and prevent further water quality exceedances
3. Ensure all BMPs specified in the HDD Plan are installed and functioning as intended.
4. Assess whether additional BMPs should be implemented.
5. Increase frequency of visual monitoring or switch to physical monitoring as indicated in Table-2.
6. Perform turbidity monitoring as required to determine the extent of the plume (refer to Table-2).
7. Do not resume operations until issues are resolved and state water quality standards are restored are restored.
8. Notify Ecology per the Water Quality Certification within 24 hours of analysis (email: fednotification@ecy.wa.gov).

4.2 pH Monitoring

If a frac-out or other release of grout material occurs, pH monitoring will be conducted using a pH meter at the frac-out location. The frac-out contingency plan will be implemented to ensure appropriate measures are taken. pH must be within the range of 7.0 to 8.5 with a human caused variation within the above range of less than 0.5 units. There is no “area of mixing” associated with pH. Monitoring shall be at the source.

If there is exceedance of state water quality standards for pH, the following steps shall be taken: Stop work immediately and assess the cause of the water quality problem. Take immediate action to isolate and stop the source, contain and correct the problem, and prevent further water quality exceedances. Inform Ecology within 24 hours.

There is no standard frequency for pH monitoring.

Table 3. pH Monitoring Frequency

Activity	Monitoring Frequency (w/out exceedance)	Monitoring Frequency (w/exceedance)
HDD Exit/Reaming	2-Hours	1-Hour[1]
Frac-out	Immediate[3]	1-Hour[2]

Footnotes:
1. Until an exceedance is no longer detected/or until WQ standards are met.
2. Until pH-altering source is neutralized and WQ standards are met.
3. An immediate response to determine if there is an exceedance.

4.3 Oil and Sheen

Visual monitoring for oil and sheen will be employed throughout HDD work and cable installation. During all marine operations activities, visual monitoring for a potential release of oil or other fluids will be conducted. If any oil or sheen is observed, work will stop and appropriate measures will be taken to contain and clean up the release in accordance with each vessel's spill response plan.

5.0 REPORTING

5.1 Frequency/Format

A monitoring report will be submitted to Department of Ecology in accordance with requirements set forth in the 401 Water Quality Certification.

5.2 Detection of Exceedances

Any results exceeding water quality standards will be promptly reported to Department of Ecology in accordance with permit requirements.

6.0 APPENDIX

6.1 Forms for Monitoring Records

Hat Island Turbidity Readings

Work activity (circle one): HDD HDDExit Cable Install FracOut	
Date:	Tidal Stage (cirlcle one): Ebb Flood Slack
Time:	Sampler Name:
GPS Coordinates:	
Background Turbidity	Backgroung Sample Location:
Sampler Name:	Weather Conditions (Observed):

Depth	pH	Background (NTU)	Turbidity (NTU)	Exceedance	%	Observations / Comments (ie.sheen present?)
20-feet						
40-feet						
60-feet						
80-feet						
100-feet						
120-feet						
140-feet						

pH must be within the range of 7.0 to 8.5 with a human- caused variation within the above range of less than 0.5 units

Turbidity Exceedance = Background NTU + 5 NTU if background < 50 NTU (or 10% increase if background > 50 NTU)

Hat Island Turbidity Readings

Date:	Tidal Stage (cirlcle one): Ebb Flood Slack
Time:	Sampler Name:
GPS Coordinates:	
Background Turbidity	Backgroung Sample Location:
Sampler Name:	Weather Conditions (Observed):
Sampler Name:	Weather Conditions (Observed):

Depth	pH	Background (NTU)	Turbidity (NTU)	Exceedance	%	Observations / Comments (ie.sheen present?)
20-feet						
40-feet						
60-feet						
80-feet						
100-feet						
120-feet						
140-feet						

pH must be within the range of 7.0 to 8.5 with a human- caused variation within the above range of less than 0.5 units

Turbidity Exceedance = Background NTU + 5 NTU if background < 50 NTU (or 10% increase if background > 50 NTU)

BUSINESS OF THE COMMISSION

Meeting Date: December 2, 2025 **Agenda Item:** 8C

TITLE

Consideration of a Resolution Authorizing the CEO/General Manager of Public Utility District No. 1 of Snohomish County to Execute an Amendment to an Interlocal Agreement With the City of Everett and Ratifying an Amendment to a Grant Agreement With the Washington State Department of Commerce, all Regarding the Purchase, Installation and use of a Charging System for Electric Buses at College Station at Everett Community College

SUBMITTED FOR: Items for Individual Consideration

Strategic Accounts	Suzanne Oversvee	8291
Department	*Contact*	*Extension*

Date of Previous Briefing: November 18, 2025
Estimated Expenditure: Presentation Planned ☐

ACTION REQUIRED:

☐ Decision Preparation
☐ Policy Discussion
☐ Policy Decision
☒ Statutory

☐ Incidental (Information)

☐ Monitoring Report

SUMMARY STATEMENT:

Identify the relevant Board policies and impacts:

Governance Process, Board Job Description, GP-3(4) …non-delegable, statutorily assigned Board duty. Board action is required for an interlocal agreement by RCW 39.34.030(2) and RCW 39.34.080.

Pursuant to a grant ("Grant") from the Washington State Department of Commerce ("Department of Commerce") and the Interlocal Cooperation Act (RCW Chapter 39.34), on October 29, 2021, the District and the City of Everett ("City") entered into an Interlocal Agreement ("ILA") to partner on the installation of a resonant magnet induction bus charging system at Eclipse Mill Park to enable enroute charging of electric buses.

The City commenced construction of the resonant magnet induction bus charging system at Eclipse Mill Park and then paused construction upon discovery of methane. Upon completion of a study to determine the extent of the methane and required project changes in light of the substantial

electrical power needed for resonant magnet induction, the City determined the project was no longer feasible at Eclipse Mill Park. The District and the City then collaborated to evaluate alternate sites to meet the original intent of the project and consulted with the Department of Commerce to ensure alignment on Grant requirements and goals. The District, the City and the Department of Commerce tentatively agreed that College Station at Everett Community College was an appropriate alternative location for the installation of Electric Vehicle Supply Equipment in the form of a cabinet charger ("EVSE").

On October 6, 2025, the District and the Department of Commerce executed an amendment to the Grant agreement to reflect the installation of the EVSE at the alternate site.

Staff from the District and the City have now reached tentative agreement on an amendment to the ILA reflecting the alternative location for the installation of the EVSE.

RECOMMENDATIONS/FUTURE ACTIONS:

District staff recommends that the District Board of Commissioners pass the resolution authorizing execution of the proposed ILA amendment with the City and ratifying the amendment of the Grant agreement with the Department of Commerce.

List Attachments:

Resolution
Attachment 1
Attachment 2

RESOLUTION NO. _____

A RESOLUTION Authorizing the CEO/General Manager of Public Utility District No. 1 of Snohomish County to Execute an Amendment to an Interlocal Agreement With the City of Everett and Ratifying an Amendment to a Grant Agreement With the Washington State Department of Commerce, all Regarding the Purchase, Installation and use of a Charging System for Electric Buses at College Station at Everett Community College

WHEREAS, pursuant to a grant ("Grant") from the Washington State Department of Commerce ("Department of Commerce") and the Interlocal Cooperation Act (RCW Chapter 39.34), on October 29, 2021, the District and the City of Everett ("City") entered into an Interlocal Agreement to partner on the installation of a resonant magnet induction bus charging system at Eclipse Mill Park to enable enroute charging of electric buses; and

WHEREAS, the City commenced construction of the resonant magnet induction bus charging system at Eclipse Mill Park and then paused construction upon discovery of methane; and

WHEREAS, upon completion of a study to determine the extent of the methane and required project changes necessary to cope with the methane in light of the substantial electrical power needed for resonant magnet induction, the City determined the project was no longer feasible at Eclipse Mill Park; and

WHEREAS, the District and the City collaborated to evaluate alternate sites to meet the original intent of the project and consulted with the Department of Commerce to ensure alignment on Grant requirements and goals; and

WHEREAS, the District, the City and the Department of Commerce tentatively agreed that College Station at Everett Community College was an appropriate alternative location for

the installation of Electric Vehicle Supply Equipment in the form of a cabinet charger ("Electric Vehicle Supply Equipment" or "EVSE"); and

WHEREAS, on October 6, 2025, the District and the Washington State Department of Commerce executed an amendment to the Grant agreement to reflect the installation of the EVSE at the alternate site; and

WHEREAS, staff from the District and the City have reached tentative agreement on an amendment to the ILA reflecting the alternative location for the installation of the EVSE; and

WHEREAS, District staff recommends that the District Board of Commissioners authorize execution of the proposed ILA amendment with the City and ratify the amendment of the Grant agreement with the Department of Commerce.

NOW, THEREFORE, BE IT RESOLVED by the Commission of Public Utility District No. 1 of Snohomish County as follows:

1. The CEO/General Manager, or his designee, is authorized to execute, in the name of the District, an Amendment to the Interlocal Agreement with the City of Everett regarding the purchase, installation and use of Electric Vehicle Supply Equipment for electric buses at College Station at Everett Community College in substantially the form attached as Attachment No. 1.

2. The amendment of the Grant agreement with the Washington State Department of Commerce attached hereto as Attachment No. 2 is hereby ratified.

PASSED AND APPROVED this 2nd day of December, 2025.

_____
President

_____
Vice-President

_____
Secretary

AMENDMENT NO. 1 TO THE INTERLOCAL AGREEMENT BETWEEN THE CITY OF EVERETT AND PUBLIC UTILITY DISTRICT NO. 1 OF SNOHOMISH COUNTY

This Amendment No. 1 ("Amendment") to the Interlocal Agreement ("Agreement") is made and entered into by and between Public Utility District No. 1 of Snohomish County, a Washington State municipal corporation ("District"), and the City of Everett, a Washington State municipal corporation ("City"). The District and the City are also referred to herein individually as "Party" and collectively as "Parties."

RECITALS

WHEREAS, pursuant to a grant ("Grant") from the Washington State Department of Commerce ("Department of Commerce") and the Interlocal Cooperation Act (RCW Chapter 39.34), on October 29,2021, the District and the City entered into an Interlocal Agreement to partner on the installation of a resonant magnet induction bus charging system at Eclipse Mill Park to enable en-route charging of electric buses.

WHEREAS, the City commenced construction of the resonant magnet induction bus charging system at Eclipse Mill Park and then paused construction upon discovery of methane.

WHEREAS, upon completion of a study to determine the extent of the methane and required project changes necessary to cope with the methane in light of the substantial electrical power needed for resonant magnet induction, the City determined the project was no longer feasible at Eclipse Mill Park.

WHEREAS, the District and the City collaborated to evaluate alternate sites to meet the original intent of the project and consulted with the Department of Commerce to ensure alignment on Grant requirements and goals.

WHEREAS, the District, the City and the Department of Commerce tentatively agreed that College Station at Everett Community College was an appropriate alternative location for the installation of electric vehicle supply equipment in the form of a cabinet charger ("Electric Vehicle Supply Equipment" or "EVSE").

WHEREAS, on October 6, 2025, the District and the Washington State Department of Commerce executed an amendment to the Grant agreement to reflect the installation of EVSE at the alternate site.

NOW, THEREFORE, the District and City agree to amend the Interlocal Agreement as follows (deleted words are stricken through and added words are underlined):

1. Section 1.2 of the Interlocal Agreement is amended as follows:

1.2 Purpose of Agreement. The purpose and intent of this Agreement is to facilitate implementation of the Project. The District shall be primarily responsible for: managing the Grant and the Grant Agreement; acting as the main point of contact on the Grant with the Washington State Department of Commerce; facilitating reimbursement of Everett Transit expenses for Grant-eligible work; and evaluating load management, grid optimization and electric rate strategies regarding the Project for a period of five (5) years. The City shall be responsible for: purchasing and obtaining the EVSE~~resonant magnet induction charging system~~; procuring EVSE installation services; coordinating installation of the EVSE~~resonant magnet induction charging system~~; owning, maintaining and operating the

EVSE~~resonant magnet induction charging system~~ and providing the District access to the system for a period of five (5) years.

2. Section 3.2 and 3.4 of the Interlocal Agreement are amended as follows:

3.2 Right to Control the EVSE. During the duration of this Agreement and/or the five (5) year minimum useful life of the EVSE~~resonant magnet induction charging system~~, the District shall have the right to exercise control at any time of the EVSE~~resonant magnet induction charging system~~ and the right to ensure it is used for the Grant purposes.

3.4 Evaluation of Charging System. The District will, for a period of five (5) years from the time the charging system is first utilized by Everett Transit, evaluate load management and grid optimization strategies compatible with transit service requirements to optimize the electric grid for this and related EV charging technologies. The District will also use this Project to evaluate if current electric rate structures are compatible with en-route ~~induction~~ charging patterns, including a new Time of Day rate for which the City is a pilot participant.

3. Sections 4.1, 4.2, 4.3, 4.6, and 4.7 of the Interlocal Agreement are amended as follows:

4.1 Prior Approvals. The City shall, at its sole cost and expense but with Grant reimbursement from the District as set forth in this Agreement, obtain any and all necessary federal, state or municipal licenses, permits and/or approvals for the installation, maintenance and operation of the EVSE~~resonant magnet induction charging system~~. The District shall cooperate and assist in obtaining all of such licenses, permits and approvals.

4.2 Equipment Purchase and Installation. The City shall, at its sole upfront cost and expense but with Grant reimbursement from the District as set forth in this Agreement, purchase the EVSE~~resonant magnet induction charging system~~ and arrange for its installation at ~~Eclipse Mill Park (formerly the "Riverfront park")~~College Station per the attached Project proposal technical specifications in Exhibit "B."

4.3 Connection to District System. The City shall, at its upfront sole cost and expense but with Grant reimbursement from the District as set forth in this Agreement, be responsible for the interconnection of the EVSE~~resonant magnet induction charging system~~ to the District's meter and electric utility system.

4.6 Grant Reimbursement and Matching Funds. Upon request from the District, the City will provide documentation of eligible Grant expenses for Project cost reimbursement and matching fund requirements. Eligible Grant expenses must be necessary for and directly connected to the acquisition and installation of the ESVE~~electric vehicle supply equipment (*i.e.*, resonant magnet induction charging system)~~. Examples of Grant eligible expenses include without limitation: EVSE and construction materials; EVSE electrical connectivity; personnel costs for site design, site preparation and installation; load management; and signage. The Grant was awarded on a 10:1 grant to project match basis. The City will be responsible for 49% of the match requirement. Eligible Grant expenses will be reimbursed by Commerce to the District and then to the City as agreed upon milestones are completed per the project budget and scope as described in Exhibit "A."

4.7 Project Cost Overruns. The District received the Grant in an amount not to exceed $728,780 in grant funds to be matched with $72,878 in funds to be provided on a basis of 51% by the District and 49% by the City. If Project costs incurred by the City, including costs associated with construction at

the original Eclipse Mill Park site, exceed $801,658, those excess costs will be the responsibility of the City.

4. The Grant Agreement with the Washington State Department of Commerce that is referenced as Exhibit "A" to the Interlocal Agreement has been amended in accordance with attached Commerce Contract #21-92201-012 Amendment A.

5. Substitute and incorporate attached and revised Exhibit B – Technical Specifications for the Exhibit B – Technical Specifications that was originally attached to and incorporated in the Interlocal Agreement.

6. The Amendment shall be effective upon full execution by the Parties.

7. Except as modified herein, the original Agreement remains in full force and effect.

PUBLIC UTILITY DISTRICT NO. 1
OF SNOHOMISH COUNTY

By:_____
John Haarlow
CEO/General Manager
Date:_____

Approved as to Form:

_____

Date:_____

CITY OF EVERETT

By:_____
Cassie Franklin
Mayor
Date:_____

Approved as to Form:

_____

Date:_____

Exhibit B

ChargePoint® Express Plus

A flexible DC fast charging platform that grows with you.



Express Plus Specifications

Express Plus Power Module

Express Plus Power Module Output	
Max Output Power	40 kW
Max Output Current	100 A
Power Conversion Efficiency	Up to 96%
Power Factor	0.99 at full load

Express Plus Power Module Specifications	
Power Module Dimensions	430 mm (H) x 130 mm (W) x 760 mm (L) (1 ft 5 in x 5 ft x 2 ft 6 in)
Power Module Weight	45 kg (98.5 lb)
Power Module Cooling	Liquid Cooled Technology
Harmonics	iTHD < 5% (Complies with IEEE 519)

Express Plus Power Block

Express Plus Power Block Input	
Input Rating	3-phase, 400-480Y VAC, 310-260 A 50/60 Hz (200 kW) Optional: 3-phase, 400-480Y VAC, 255-210 A 50/60 Hz (160 kW)
Wiring	L1, L2, L3, Earth
Short Circuit Current Rating	65 kA

Express Plus Power Block Output	
Max Output Power	200 kW Optional: 160 kW
Output Voltage, Charging	100 to 1000 VDC
Max Current per Output	250 A, 300 A, 350 A, 500 A
Number of Stations Served	One Power Block can serve up to 2 Power Link stations. Additional Power Blocks can be added to serve more stations or increase power output.
Max Power Modules per Power Block	5

Express Plus Power Block Specifications	
Power Block Dimensions	2191 mm (H) x 988 mm (W) x 1039 mm (L) (7 ft 3 in x 3 ft 3 in x 3 ft 5 in)
Power Block Weight	455 kg (1000 lb) without Power Modules
Power Block Enclosure Rating	Type 3R, IP56, IK10

Express Plus Power Link 2000

Express Plus Power Link Output	
Max Output Power per Connector	Up to 500 kW, dependent on cable amperage and Power Block configuration
Output Voltage, Charging	100 to 1000 VDC
CCS1 Max Output Current	Option 1: 250 A continuous with Power Blocks Option 2: 350 A continuous with Power Blocks Option 3: 500 A continuous liquid cooled cable with Power Blocks
CCS2 Max Output Current*	Option 1: 250 A continuous with Power Blocks Option 2: 300 A continuous with Power Blocks Option 3: 500 A continuous liquid cooled cable with Power Blocks
CHAdeMO Max Output Current*	North American and Europe: 200 A continuous with Power Blocks

* Availability may vary

Express Plus Power Link Specifications	
Station Dimensions	See Diagrams below
Station Footprint	See Diagrams below
Station Weight	Approximately 209 kg (459 lb). Refer to Site Design Guide for more details.
Number of Connectors*	Up to 2 connectors per station. Simultaneous or sequential charging.
Supported Connector Types	CHAdeMO, CCS1 (SAE J1772™ Combo), CCS2 (IEC 61851-23)
Cable Length	Standard 4.5 m (15 ft) with Cable Management Kit (CMK)** Optional 7.6m (25ft) with cable management
Station Enclosure Rating	Type 3R, IP56, IK10 (Except credit card chip reader)
Locking Holster	Optional for Pedestal stations
Mounting Type	Ground, Overhead (Non-Liquid Cooled Cable Only), Wall (Non-Liquid Cooled Cable Only)

* *Horizontal reach to typical vehicle charging port: 3.76 m (12 ft 4 in)

Express Plus Specifications

Functional Interfaces	
Indicators	Multicolor LEDs
LCD Display	Optional: Full color 203 mm (8 in) interactive display with full motion video, UV protection, gesture touch controls, and multi-language support
Authentication	RFID: ISO 15693, ISO 14443, NEMA EVSE 1.2-2015 (UR) Tap to Charge (NFC on Apple & Android) Contactless credit card Remote: Mobile and in vehicle (If supported by vehicle) ISO 15118-2, Plug&Charge Optional: Credit card chip reader

Connectivity Features	
Local Area Network	2.4 GHz and 5 GHz WiFi (802.11 b/g/n)
Wide Area Network	4G LTE
Supported Communication Protocols	OCPP 2.0.1
Service and Maintenance	Remote system monitoring, diagnostic, and proactive maintenance

Safety Ratings & Protocol	
Vehicle Communication	CHAdeMO: JEVS G104 over CAN CCS1: SAE J1772 over PLC CCS2: IEC 61851-23, ISO 15118
Plug-Out Detection	Power terminated per JEVS G104 (CHAdeMO), SAE J2931 (CCS1) and IEC 61851-23 (CCS2)
Safety Compliance	cUL and UL listed. Complies with UL 2202, UL 2231-1, UL 2231-2 CE and UKCA marked. Complies with IEC 61851-1 and IEC 61851-23 (In progress)
Surge Protection	Tested to IEC 61000-4-5, Level 5 (6 kV @ 3,000 A)
EMC Compliance	North America: FCC part 15 Class B Europe: EN55011, EN55022, and IEC61000-6-3 Class B

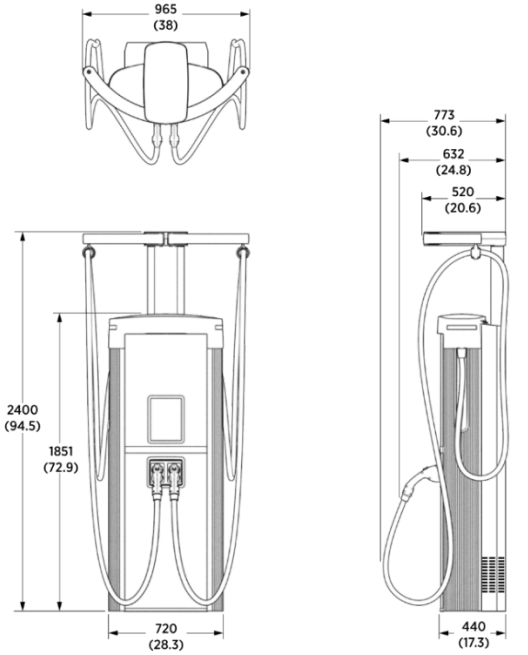
Generic Specifications	
Operational Altitude	< 3,000 m (9,800 ft)
Operating Temperature	-40°C to 50°C (-40°F to 122°F) with derating
Storage Temperature	-40°C to 70°C (-40°F to 158°F)
Operating Humidity	Up to 95% at 50°C (122°F) non-condensing
Metering	Eichrecht (In progress)
Buy America	Buy America (FTA & FHWA) options available upon request

Energy Management Features	
Dynamic Power Management	Allows a fixed maximum power output per station or lets the system dynamically manage the power distribution per station
Remote Energy Management	Manage output power via the ChargePoint Admin Portal, API, and Open ADR 2.0b VEN

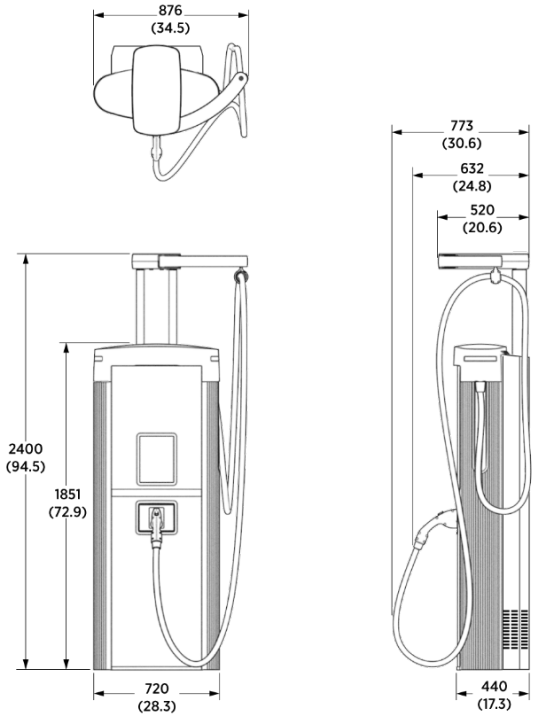
Architectural Drawings

Note: Images are not to scale. Measurements appear in metric units (mm), followed by imperial equivalents(inches).

Express Plus Power Link 2000, with liquid cooled cable, dual connectors

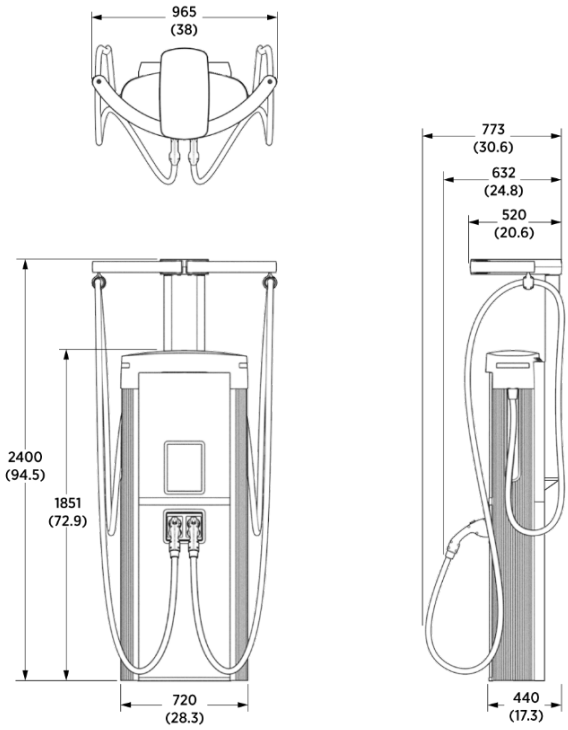


Express Plus Power Link 2000, with liquid cooled cable, single connector

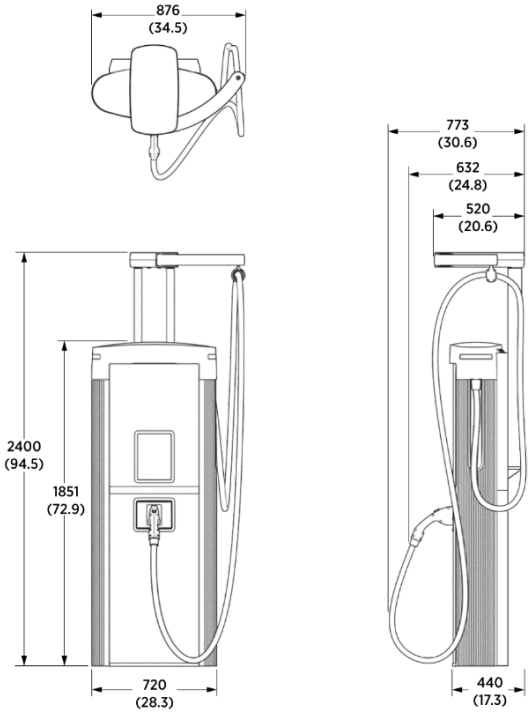


Note: Images are not to scale. Measurements appear in metric units (mm), followed by imperial equivalents(inches).

Express Plus Power Link 2000, with non-liquid cooled cables, dual connectors

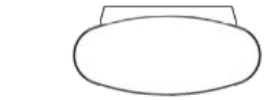


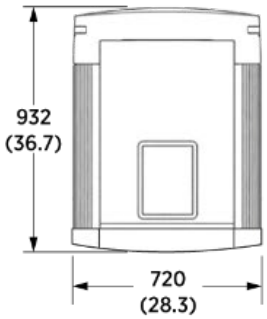
Express Plus Power Link 2000, with non-liquid cooled cables, single connector

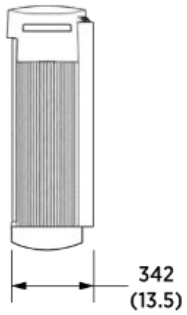


Note: Images are not to scale. Measurements appear in metric units (mm), followed by imperial equivalents(inches).

Express Plus Overhead Mounting Option

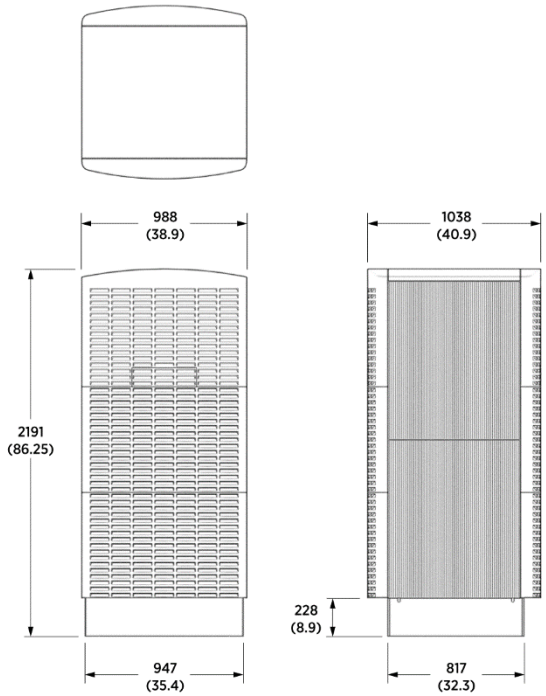




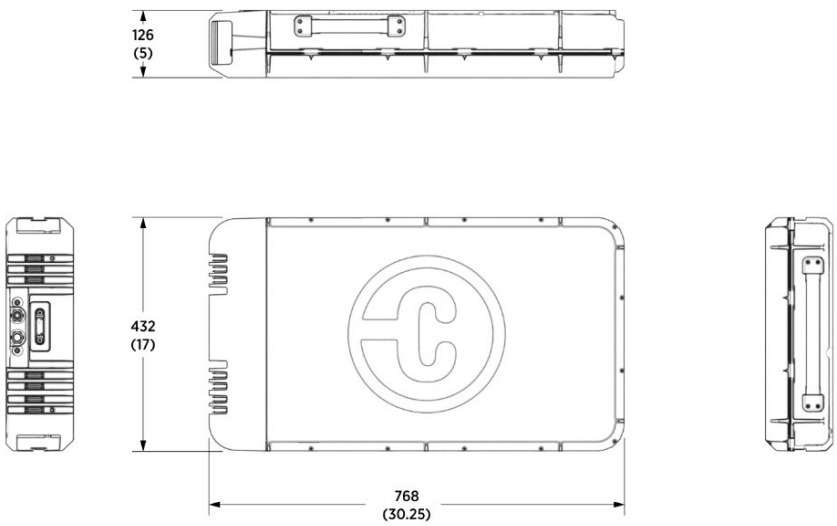


Note: Images are not to scale. Measurements appear in metric units (mm), followed by imperial equivalents(inches).

Express Plus Power Block



Express Plus Power Module





72-002845-01r2

ChargePoint, Inc.
240 East Hacienda Avenue
Campbell, CA 95008-6617 USA
+1 408.841.4500 or +1 877.370.3802
US and Canada toll-free

Contact Us
Visit chargepoint.com
Email sales@chargepoint.com

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Category 1: Sensitive information

Amendment

Contract Number: **21-92201-012**
Amendment Number: **A**

Washington State Department of Commerce

ENERGY DIVISION
ENERGY PROGRAMS IN COMMUNITIES (EPIC) UNIT
CLEAN ENERGY FUND – ELECTRIFICATION OF TRANSPORTATION SYSTEMS

1. Contractor Public Utility District No. 1 of Snohomish County 2320 California St Everett, WA 98201		**2. Contractor Doing Business As (optional)** N/A	
3. Contractor Representative (only if updated)		**4. COMMERCE Representative (only if updated)** Kaitlyn Sledge CEF Program Manager 360-725-5084 epicgrants@commerce.wa.gov PO Box 42525 1011 Plum St SE Olympia, WA 98504-2525	
5. Original Contract Amount (and any previous amendments) $728,780	**6. Amendment Amount** $0	**7. New Contract Amount** $728,780	
8. Amendment Funding Source **Federal:** **State:** x **Other:** **N/A:**		**9. Amendment Start Date** September 1, 2025	**10. Amendment End Date** June 30, 2026
11. Federal Funds (as applicable): **NA**	**Federal Agency:** **NA**	**ALN:** **NA**	

12. Amendment Purpose: This amendment **e**xtends the contract by 9 months, updates the budget milestones, and updates the site address to meet the needs of a necessary site change. This site change was made due to a methane hazard discovered during the construction phase.

COMMERCE, defined as the Department of Commerce, and the Contractor, as defined above, acknowledge and accept the terms of this Contract As Amended and attachments and have executed this Contract Amendment on the date below to start as of the date and year referenced above. The rights and obligations of both parties to this Contract As Amended are governed by this Contract Amendment and the following other documents incorporated by reference: Contractor Terms and Conditions including Attachment "A" – Scope of Work, Attachment "B" – Budget, Attachment "C" – Reporting, Attachment "D" – Budget Proviso Language, and Attachment "E" – Site List. A copy of this Contract Amendment shall be attached to and made a part of the original Contract between COMMERCE and the Contractor. Any reference in the original Contract to the "Contract" shall mean the "Contract as Amended".

FOR CONTRACTOR

Signed by:
John Hoffman
5D59F09F534D412...

John Hoffman, Chief Customer Officer

10/1/2025 | 8:20 AM PDT
Date

FOR COMMERCE

Signed by:
Jennifer Grove
F2BC0EF83F1534A...

Jennifer Grove, Assistant Director, Energy Division

10/6/2025 | 11:58 AM PDT
Date

APPROVED AS TO FORM ONLY
BY ASSISTANT ATTORNEY GENERAL
SIGNATURE ON FILE

Category 2: For official use only/disclosure permissible by law.

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Amendment

This Contract is **amended** as follows:

ATTACHMENT A – SCOPE OF WORK

Purpose:
Snohomish Public Utility District (PUD) will partner with Everett Transit (ET) to install an en-route ~~inductive~~ fast cabinet charging station as a demonstration project for the ET service area, and other regional transit agencies and fleets. This project supports strategic objectives of the PUD's Electric Transportation Plan, and the City of Everett's (City) Climate Action Plan.

Project goals include:
1) Successfully install one ~~in-ground inductive~~ fast cabinet electric bus charger to be in service for a minimum of five years and fully utilized by ET buses upon installation;
2) Extend daily electric bus utilization from a current rate of 80% to 100% to equate to diesel-bus utilization; and
3) Evaluate and implement load management strategies compatible with transit service requirements to optimize the electric grid for this and related EV charging technologies.

ET's next purchase of electric buses is planned for ~~2022~~ 2025 and will include ~~nine~~ fourteen buses with cabinet and inductive charging capability, so buses stay in service all day. This proposed project will provide en-route charging capability during bus layovers at ~~Eclipse Mill Park~~ College Station. On any given day two to three ~~inductive charging~~ electric buses ~~would~~ will be assigned to this route, six to seven days a week. This project will serve as a demonstration site for future en-route charging projects in ET and PUD service areas.

The project will be integrated into outreach and education associated with the City of Everett Climate Action Plan and existing PUD educational programming. PUD will partner with ET to install educational signage at the charging site. Through ET's relationship with the Imagine Children's Museum in Everett, lessons will be added on ~~induction charging~~ transit electrification to the museum's EV curriculum.

ET's commitment to expanding its electrified bus fleet and collaborating with the PUD will increase PUD's knowledge of charging infrastructure and drive customer process improvements for both municipal and commercial fleets charging needs. This project will inform other public transit system's electrification expansion while supporting the PUD in meeting charging infrastructure needs.

Specifically, the PUD plans to gain experience from this project to understand:
- Capacity and demand impacts due to en-route fast-charging of buses compared to conventional depot charging. These impacts will be evaluated at the resource, transmission and feeder level of the system.
- Opportunities for load management; and
- If current rate structures are compatible with en-route induction charging patterns, including a new PUD Time of Day rate for which ET is a pilot participant.

The PUD plans to work with ET to deploy the following load management approaches for this project:
- Load shifting away from peak load times.
- Utilizing a Time of Day rate or other rate structure to incentivize load shifting and/or mitigate for excessive demand charges.

Major Components		
Quantity	**Description**	**Site(s) Affected**
1	**~~In-ground inductive~~ Fast cabinet electric bus**	**~~Eclipse Mill Park~~**

Category 2: For official use only/disclosure permissible by law.

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	charger	College Station

Description of Miscellaneous Major Cost Items

~~In-ground inductive~~ Fast cabinet electric bus charger consists of ~~a transformer~~ a Power Link tower, power block, and switch gear, ~~charging cabinet, and charging system (pads).~~ Civil work includes significant concrete paving work to route electrical service from an existing transformer to the charger location.

Project Siting

The project will be located at 2108 Tower Street College Station, one of Everett Transit's busiest hubs. In 2024-2025 (August to July), over 1.2 million riders were served by the four College Station routes, roughly 74% of Transit's annual ridership. Importantly College Station is at the center of the Everett Community College campus and within walking distance of the Washington State University Everett campus, serving students and faculty alike. College Station serves and provides vital connections for vulnerable and under-served communities and populations with connections to Providence Medical center, the area's largest hospital, and social service agencies such as the nearby Department of Social and Health Services. College Station also provides a major North-South service link spanning Transit's entire service corridor including as far south as Silver Lake, a regional recreation destination, Everett Mall shopping complex, and the South Everett Park and Ride, linking patrons to King County and beyond. ~~the new Eclipse Mill Park, 3535 Riverfront Boulevard Everett, WA 98201 College Station transit stop is The site is adjacent to near a highly impacted community and sensitive waterway, the Snohomish River. 250 income-qualified housing units are planned in the adjacent this community. The Waterfront-Riverfront route serves a highly vulnerable community, with 20% of the population residing within ¼ mile of the route falling below the federal poverty level. The Riverfront site is a former landfill and the site of the historic 1984 Everett tire fire. This innovative charging system aligns with this neighborhoods' environmental and socioeconomic revitalization by powering ET's buses with clean reliable energy. The site was identified as a bus zone during the design phase of the Riverfront development project; it includes an existing bus layover adjacent to Everett Community College and WSU Everett campuses. City staff was informed of the potential for inductive fast cabinet charging and included as an option in the master plan.~~

ATTACHMENT B – BUDGET

All funding is subject to continued legislative authorization and re-appropriation where applicable.

Milestone	Milestone and Task Description	Key Deliverable(s)	Activity Period	Percent of CEF Grant	$ Applicant Match	$ Amount of CEF Grant
A	**Project Development and Confirmation**					
	Contract Agreement with Everett Transit	Executed Interlocal Agreement	Q3 '21	0.0%		$0
	Project Plan	Overview document	Q4 '21	0.3%		$2,500
	Procurement Plan	Report document	Q4 '21	0.3%		$2,500
	Risk Plan	Report document	Q4 '21	0.3%		$2,500
	Load Management Plan	Report document	Q4 '21	0.8%		$5,500
			Activity A Subtotal	**1.8%**	**$8,000**	**$13,000**
B	**Engineering Design**					
	EVSE System	Procurement technical specs	Q3 '23	0.5%		$4,000
	Electrical design	100% design submittal	Q3 '23	4.4%		$32,250
	Project schedule	MS Project Report or similar	Q3 '23	0.6%		$4,500
	Civil design and permitting	100% design submittal	Q3 '23	5.8%		$42,420
			Activity B Subtotal	**11.4%**	**$8,000**	**$83,170**
C	**Contracting & Procurement**					
	Civil work	Copy of award letter and contract	Q4 '25	1.1%		$8,000
	EVSE Supply and Installation	Copy of award letter and contract	Q4 '25	1.1%		$8,000
	EVSE Signage Design & Contract	Copy of contract & design	Q4 '25	0.5%		$4,000
			Activity C Subtotal	**2.7%**	**$8,000**	**$20,000**
D	**Equipment Delivery, Installation & Construction**					
	Site preparation/Civil work	Substantial completion of contract	Q1 '26	~~32.7%~~35.6%		~~$238,500~~ $259,145
	EVSE installation	System delivered and installed	Q1 '26	~~33.2%~~36.0%		~~$242,000~~ $262,645
	EVSE Signage installation	Signage delivered and installed	Q1 '26	1.7%		$12,170

			Activity D Subtotal	**~~67.6%~~73.3%**	**$16,000**	**~~$492,670~~ 533,960**
~~E~~	~~**Contingency**~~					
	~~Contingency~~	~~Approved Change Order~~	~~Q2 '26~~	~~5.7%~~		~~$41,290~~
			~~**Activity E Subtotal**~~	~~**5.7%**~~	~~**$4,129**~~	~~**$41,290**~~
~~F~~E	**Systems Integration & Commissioning**					
	EVSE commissioning	Certified SAT report	Q1 '26	2.2%		$15,910
	Load Management technology integration	System integration report	Q1 '26	2.0%		$14,576
			Activity E Subtotal	**4.2%**	**$8,000**	**$30,486**
~~G~~F	**Analytics & Monitoring**					
	Utilization data monitoring	Charger status and usage reports	Q2 '26	2.5%		$18,000
	Maintenance Plan	Operation and Maintenance Training and Manuals	Q2 '26	2.5%		$18,000
	Load Management data analytics	Load Management reports	Q2 '26	1.7%		$12,164
			Activity F Subtotal	**6.6%**	**$24,878**	**$48,164**
			Budget Total	100.0%	$72,878	$728,780

Milestone	Project Activity and Task	Key Deliverable(s)	Deliverable Description
A	**Project Development and Confirmation**		
	Project Plan	Overview document	Executive summary and project plan.
	Procurement Plan	Report document	Report describing the procurement plan.
	Risk Plan	Report document	Report describing the risk management plan.
	Load Management Plan	Overview document	Documentation of load management strategy including applicable technology and methodology to be utilized, and expected data to be collected.

B	**Engineering Design**		
	EVSE System	Procurement technical specs	Final equipment technical specifications for procurement of EVSE supplies and installation services.
	Electrical design	100% design submittal	Letter of Confirmation to (sub)contractor that design efforts are complete or sufficient for issuing "For Construction" drawing package.
	Project schedule	MS Project Report or similar	MS Project Report or similar report detailing anticipated project schedule.
	Civil design and permitting	100% design submittal	Letter of Confirmation to (sub)contractor that design efforts are complete or sufficient for issuing "For Construction" drawing package.
C	**Contracting & Procurement**		
	Civil work	Copy of award letter and contract	Contract award letter, contract summary and Notice to Proceed.
	EVSE Supply and Installation	Copy of award letter and contract	Contract award letter, contract summary and Notice to Proceed.
	EVSE Signage Design & Contract	Copy of contract & design	Copy of proposed signage design and printing invoice and/or contract
D	**Equipment Delivery, Installation & Construction**		
	Site preparation/Civil work	Substantial completion of contract	Project construction schedule status update and Letter of Confirmation to (sub)contractor stating site preparation and civil work is "substantially complete".
	EVSE installation	System delivered and installed	Project construction schedule, Bill-of-material and delivery dates with status memo.
	EVSE Signage installation	Signage delivered and installed	Photos of installed signage and summary report.
	Change Order	Change order management plan	COMP will include roles, authority, approval and communication plans.

~~**E**~~	~~**Contingency**~~	-	-
-	~~Contingency~~	~~Approved Change Order~~	~~Grantee will submit a change order approved by themselves. The total cost from contingency and justification must be included. Change must be approved by Commerce to be eligible for funding. Upon approval, Commerce will issue payment for up to 90.9% of the cost of the change order, up to $41,290.~~
~~**F**~~ **E**	**Systems Integration & Commissioning**		
	EVSE commissioning	Certified SAT report	Letter of Confirmation to (sub)contractor EVSE System Acceptance Test complete with copy of Certified Acceptance Test.
	Load Management technology integration	System integration report	Report confirming that load management technology integration is complete.
~~**G**~~ **F**	**Analytics & Monitoring**		
	Utilization data monitoring	Charger status and usage reports	Vendor to provide cloud based portal for data access and reporting, aggregated usage data from first six months' use submitted to Commerce.
	Maintenance Plan	Operation and Maintenance Training and Manuals	Vendor to provide training and manuals for operation and maintenance.
	Load Management data analytics	Load Management reports	Report summarizing load management impact.

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ATTACHMENT E – SITE LIST

List of Sites (Attachment to the Contract)

Site #	Site Name	Site Address	City	Zip
1	~~Electric Bus En-Route Induction Charging Demonstration Project~~ College Station	~~3535 Riverfront Boulevard~~ 2108 Tower Street	Everett	98201

ALL OTHER TERMS AND CONDITIONS OF THIS CONTRACT REMAIN IN FULL FORCE AND EFFECT.

Category 2: For official use only / disclosure permissible by law.

BUSINESS OF THE COMMISSION

Meeting Date: December 2, 2025 **Agenda Item:** 9A

TITLE

Commission Reports

SUBMITTED FOR: Commission Business

Commission	Allison Morrison	8037
Department	*Contact*	*Extension*

Date of Previous Briefing: _____
Estimated Expenditure: _____ Presentation Planned ☐

ACTION REQUIRED:

☐ Decision Preparation
- ☐ Policy Discussion
- ☐ Policy Decision
- ☐ Statutory

☒ Incidental (Information)

☐ Monitoring Report

SUMMARY STATEMENT:

Identify the relevant Board policies and impacts:

The Commissioners regularly attend and participate in meetings, seminars, and workshops and report on their activities.

List Attachments:
None

BUSINESS OF THE COMMISSION

Meeting Date: December 2, 2025 **Agenda Item:** 9B

TITLE

Commissioner Event Calendar

SUBMITTED FOR: Commission Business

Commission	Allison Morrison	8037
Department	*Contact*	*Extension*

Date of Previous Briefing: _____

Estimated Expenditure: _____ Presentation Planned ☐

ACTION REQUIRED:

☒ Decision Preparation
- ☐ Policy Discussion
- ☐ Policy Decision
- ☐ Statutory

☐ Incidental (Information)

☐ Monitoring Report

SUMMARY STATEMENT:

Identify the relevant Board policies and impacts:

The Commissioner Event Calendar is enclosed for Board review.

List Attachments:

Commissioner Event Calendar

Commissioner Event Calendar – 2025

December 2025

December 4:
New Employee Orientation Program
Virtual 8:45 a.m. – 10:00 a.m.
(Logan)

December 10:
Economic Alliance of Snohomish County (EASC)
Legislative Kickoff
Everett, WA 9:00 a.m. – 11:00 a.m.
(Altamirano-Crosby/Logan/Olson)

December 2025

For Planning Purposes Only and Subject to Change at any Time

2025 Treasury, Budget, and Project Status Report for the Board of Commissioners



December 2, 2025

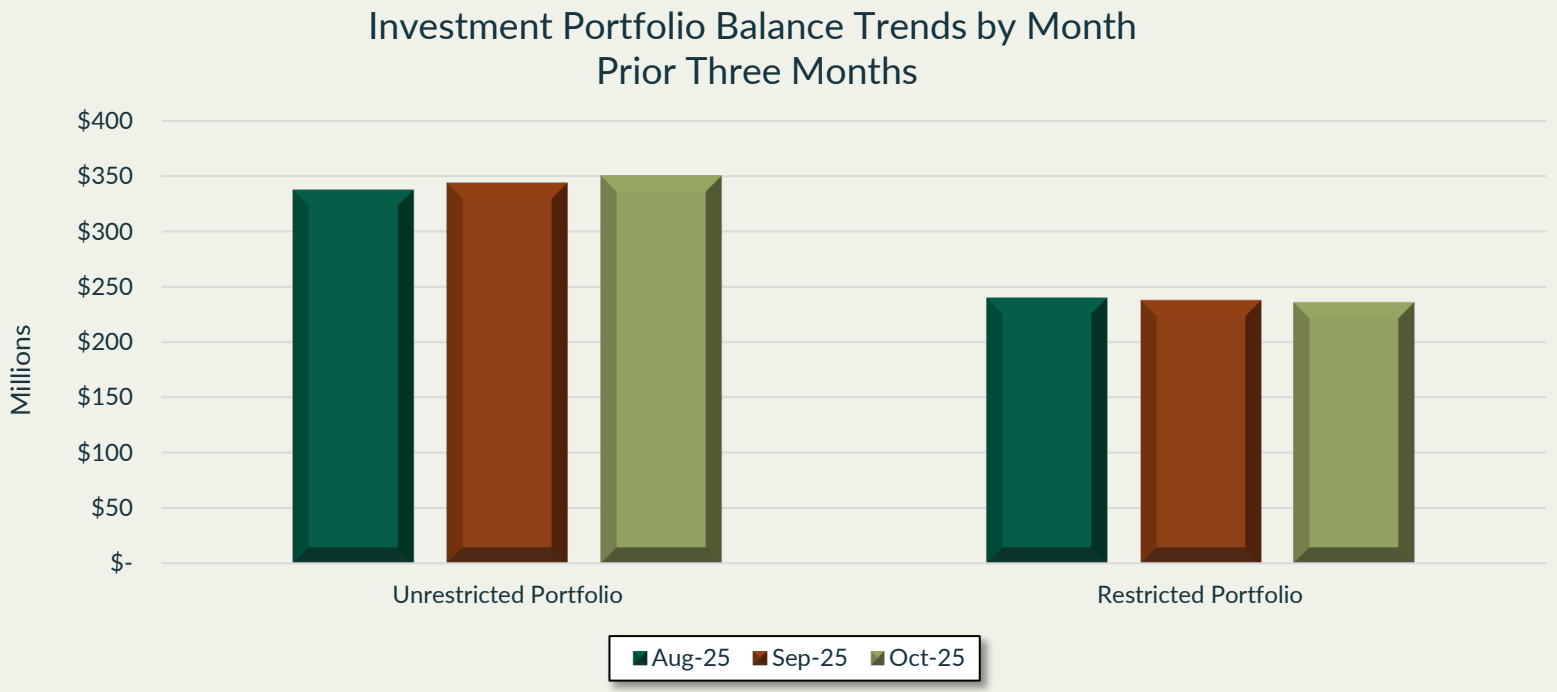
Highlights Through October 2025

Energy Retail Sales in October were steady while expenditures remained close to budget. The transition to Load Following is underway and the forecast has been updated with year end adjustments from BPA resulting in a stronger net income.





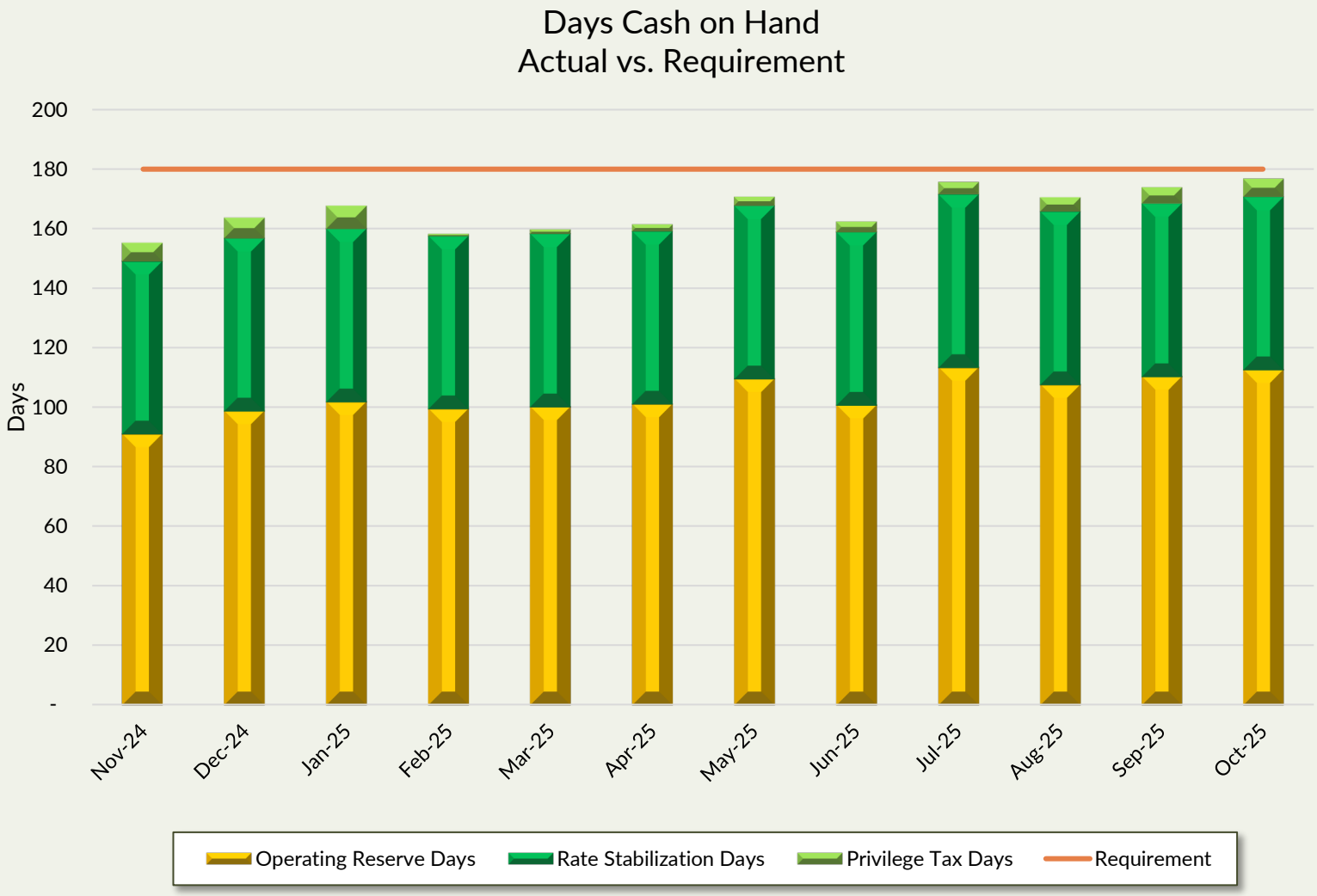
Electric System Treasury Report





- The Unrestricted Portfolio increased by $5.7M from the prior month due primarily to higher-than-average consumptive receipts.
- Proceeds received from the 2025A bond issuance, held in the Restricted Portfolio's Project Reserve, are transferred to the Unrestricted Portfolio's Operating Reserve after eligible capital expenditures are paid.
  - In 2025, $29.5M of bond funds from the 2025A construction fund have been transferred from the Restricted Portfolio to the Unrestricted Portfolio through October.
  - The remaining $16.3M in proceeds from the 2022A bond issuance were transferred through June of 2025, and the spend down of that fund is complete.

Electric System Treasury Report



Key Performance Indicators

Unrestricted Reserve Days Cash on Hand
10/31/2025: 177 Days
Requirement: 180 Days

Return on Investments
10/31/2025: 3.95%
10/31/2024: 4.07%

- The Operating Reserve increased $27.3M since December 2024, resulting from strong consumptive receipts and reimbursement of eligible capital expenditures from Electric 2022A and 2025A Revenue Bond proceeds.
- The Days Cash on Hand (DCOH) for the Unrestricted Reserves are reported in the graph. The newly adopted 180-day requirement will be phased-in through the 2027 budget cycle.
- The average return on District investments is down compared to October 2024 due to slowly declining market interest rates.
    - $15.7M of cash interest income has been earned through October 2025, higher than the $14.6M earned through October 2024, due to a larger portfolio balance associated with bond proceeds.

Electric System Budget and Forecast

Highlights Through October

- **Energy Retail Sales** through October continue to be strong keeping the year-end projection positive.
- **Energy Wholesale Sales** are lower than budget due to lower market prices and less demand. The forecast has been updated with the latest assumptions for the switch to Load Following which results in an underspend for the year.
- **Other Operating Revenues** are anticipated to be higher due to higher Excess Transmission Capacity Sales and a larger than budgeted BPA Energy Conservation Assessment (ECA) Reimbursement.
- **Purchased Power** results reflect higher market purchases made earlier in the year, partially offset by underspending in Generation and the Hay Canyon Wind project. The forecast has been updated with the latest Load Following assumptions and BPA year end adjustments resulting in an overall underspend for the year.
- **Operations & Maintenance** results reflect unbudgeted costs related to the Home Electrification and Appliance Rebates (HEARS) grant, (offset by higher Interest Income & Other Revenue) higher than planned transmission costs and material expenditures.

	($000's)		($000's)	
	YTD Budget through October	YTD Results through October	2025 Budget	2025 Projection
Operating Revenues				
Energy Retail Sales	$ 608,235	$ 623,611	$ 745,728	$ 756,653
Energy Wholesale Sales	51,380	47,807	53,824	50,773
Other Operating Revenues	26,775	33,544	32,130	41,015
Total Operating Revenues	**$ 686,390**	**$ 704,962**	**$ 831,682**	**$ 848,441**
Operating Expenses				
Purchased Power	$ 317,262	$ 309,423	$ 373,471	$ 354,272
Operations & Maintenance	251,680	251,046	302,017	311,025
Taxes	37,841	38,475	46,395	46,870
Depreciation	57,538	56,168	69,045	67,826
Total Operating Expenses	**$ 664,321**	**$ 655,112**	**$ 790,927**	**$ 779,992**
Net Operating Income	**$ 22,069**	**$ 49,850**	**$ 40,755**	**$ 68,449**
Interest Income & Other	20,826	27,213	24,991	31,370
Interest Charges	(18,931)	(17,709)	(22,717)	(23,090)
Contributions	28,112	24,963	33,735	30,586
Net Income	**$ 52,076**	**$ 84,317**	**$ 76,764**	**$ 107,315**
Capital Expenditures	$ 184,422	$ 162,853	$ 221,007	$ 203,621

Capital variance explanations on subsequent slides

Electric System Project Status Report ($000's) 6

YTD Budget	YTD Results	2025 Budget	2025 Forecast
$28,638	$26,883	$34,365	$31,356

Substation:

New: Crosswind construction is 95% complete with commissioning in 2026 and energizing by Q2-2026. Paradise and Cathcart substations and the Getchell and Maltby switching stations are all in the design phase. Getchell site civil construction is planned for 2026.

Upgrades: Camano substation rebuild is under construction with plans to energize in November. Lake Goodwin (add 115kV breaker) construction is finished and energized. Brier, Picnic Point, Canyon Park, Frontier, Westgate, Delta-Everett (new line), Stimson (convert to breaker-and-a-half) are all in the design phase.

System Reliability:

Six substation System Reliability projects are planned for 2025. Three are complete and two are in construction. Construction for the sixth project has been delayed to 2026 due to outage constraints.

Telecom:

The Next Gen Substation Transport project is on track to be completed by the end of the year. Six of seven radio sites have been installed on our radio replacement project. The high-capacity transport project between OPS and the backup data center to support IT and the ADMS project is complete.

YTD Budget	YTD Results	2025 Budget	2025 Forecast
$71,035	$53,743	$85,241	$68,340

Transmission and Distribution Projects:

Approximately 735 bad order poles including 81 transmission poles and 5.7 miles of depreciated Underground (UG) cable have been replaced.

The circuit tie to Turners Corner 1431 providing additional capacity to the SpaceX building is complete. The last section of the Twin City distribution upgrade project which includes approximately 3.4 miles of overhead (OH) rebuild along 268th St NW (~640 crew hours) is currently in construction and estimated for completion in early 2026.

Construction on the 115kV rebuild of the old Stanwood-Camano, and the Stanwood-Sills lines are underway and will be complete by end of 2026. Construction on the 115kV Crosswind line has been delayed due to Federal permitting. Construction of the Crosswinds transmission line will likely start before year end and will be complete by Q2 2026.

The current forecast shows an underspend compared to budget for the following reasons: $2M in relocation work deferred to 2026 and $2.5M for the Stimson-Stanwood 115KV Line rebuild. The Hat Island cable payment is delayed due to manufacturing. The $1.8M partial payment is not expected until 2026. The High Bridge Rd. feeder tie ($1.9M) and Cascade 5th Circuit ($1.3M) have been deferred to 2026 to address changes to planning scope and needs. Material availability will limit the release of ~$500k of system work (regulators/reclosers) in Q4.

Electric System Project Status Report ($000's)

YTD Budget	YTD Results	2025 Budget	2025 Forecast
$19,041	$22,974	$22,849	$27,091

Regional Design and Construction:
This area is largely influenced by customer-related activities. Cost of materials related to Line extension work are $2.2M over budget. This trend is expected to continue through the remainder of the year.



YTD Budget	YTD Results	2025 Budget	2025 Forecast
$5,417	$10,547	$6,500	$11,671

Emergency Work and Major Storms:
$4.0M of storm operations & maintenance dollars were reclassified as capital. The remaining variance is due to higher-than-expected call-out work which is forecasted to continue through the remainder of the year.



Electric System Project Status Report ($000's)

YTD Budget	YTD Results	2025 Budget	2025 Forecast
$24,211	$26,948	$29,483	$34,635

Connect Up Program:
We are fully staffed for deployment and proceeding at a good pace. We are currently working in the SW part of the county. Electric meter installation is over 35% with a stretch goal to be near 40% by year-end. Holidays and potential weather events could impact that in the near term. Overall program costs are still on target however customer repairs are trending higher than originally forecasted and may push costs up slightly.



YTD Budget	YTD Results	2025 Budget	2025 Forecast
$10,809	$9,319	$12,970	$11,121

SnoSmart Program Overview: The DOE continues to support and fund this Program. Year to date, $2.4M in reimbursements have been received, with another $800K in review.

Advanced Distribution Management System (ADMS) Project: Configuration sessions are progressing on schedule. Building of the Pre-Production environment has begun.

Distribution Automation Infrastructure (DAI) Project: The team is meeting with vendors to resolve supply chain delays. Previously delayed connectors and radios are now being shipped.

Corporate Historian Project: Began AVEVA PI installation on 11/3/2025 – 85% complete as of 11/14.

Budget: We expect to shift ~$1M from 2025 budget to 2026 budget due to equipment delays.

Electric System Project Status Report ($000's)

YTD Budget	YTD Results	2025 Budget	2025 Forecast
$9,503	$6,505	$ 11,403	$9,084

Transportation:
Transportation is currently tracking under budget. Unplanned equipment purchase of a tracked Digger and personnel lift offset by equipment budgeted for 2025 delayed to 2026.



YTD Budget	YTD Results	2025 Budget	2025 Forecast
$1,823	$1,048	$2,187	$1,810

Information Technology Systems:

The District's network, computer, and storage infrastructure requires regular investments to remain reliable, secure, compliant, and maintainable. IT will spend the entire capital budget by the end of the year to keep infrastructure up to date. The forecast includes strategic and operational technology projects happening across the District such as the KloudGin Schedule & Dispatch, Owner Agent, and the TWO: the Cloud projects. The variance between the budget and the forecast is primarily due to GASB 96 accounting standards/rules regarding capitalization of cloud/software-as-a-service software.



Electric System Project Status Report ($000's)

YTD Budget	YTD Results	2025 Budget	2025 Forecast
$9,270	$2,896	$11,124	$3,013

Facilities – Community Office Construction:

The site in Monroe for the East County office will not be pursued. Funds budgeted this year for site security & prep, as well as design, will be allocated to other projects that are emergent.

YTD Budget	YTD Results	2025 Budget	2025 Forecast
$4,367	$2,119	$5,241	$5,322

Facilities – Other Projects:

- EB North Tower mechanical upgrade
- Carpet replacement EB/Training Center
- Culmback Dam Telecom & OPS Microwave Roof Replacement
- ECDC Meter upgrade
- Comprehensive Plan
- VMB Tire racking
- Pavement repairs
- The VMB Lift Replacement project has been delayed until 2026, an estimated $1.4M



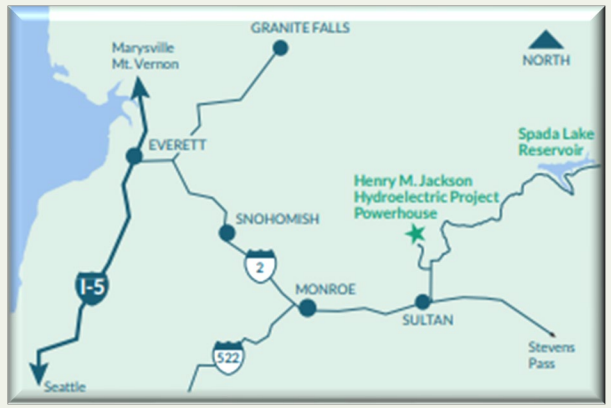


Generation System Budget and Forecast

Highlights Through October

Wholesale Sales – Energy sales to Electric are below budget due to underspending in both Operating and Maintenance and Capital.

Operations & Maintenance is tracking close to budget; projects completed and underway include roadwork, culverts and SCADA control upgrades. The cleanup and restoration from the oil spill at Jackson is estimated at $1.5M with completion expected by year end. The forecast has been updated with this expense.



	($000's) YTD Budget through October	($000's) YTD Results through October	($000's) 2025 Budget	($000's) 2025 Projection
Operating Revenues				
Wholesale Sales	$ 19,907	$ 16,212	$ 23,888	$ 20,193
Other Operating Revenues	-	420	-	420
Total Operating Revenues	**$ 19,907**	**$ 16,632**	**$ 23,888**	**$ 20,613**
Operating Expenses				
Operations & Maintenance	$ 10,835	$ 10,537	$ 13,003	$ 14,204
Taxes	81	55	98	71
Depreciation	5,083	5,365	6,100	6,382
Total Operating Expenses	**$ 15,999**	**$ 15,957**	**$ 19,200**	**$ 20,657**
Net Operating Income	**$ 3,908**	**$ 675**	**$ 4,688**	**$ (44)**
Interest Income & Other	822	1,082	987	1,246
Interest Charges	(2,896)	(2,893)	(3,476)	(3,472)
Contributions	42	2	50	10
Net Income	**$ 1,876**	**$ (1,134)**	**$ 2,249**	**$ (2,259)**
Capital Expenditures	3,832	2,006	4,598	2,772

Capital variance explanations on subsequent slides.

Generation System Project Status Report

YTD Budget	YTD Results	2025 Budget	2025 Forecast
$3,832	$2,006	$4,598	$2,772

The Jackson Switchyard transformer procurement is delayed. The transformer is being re-bid as a special facility with initial payment expected to be in Q1-2026. It is anticipated those funds will be reallocated to other Generation projects.

Jackson needle valve repairs are planned for Q2-2026 with materials purchased in 2025 (Board has approved purchase of bushings.)







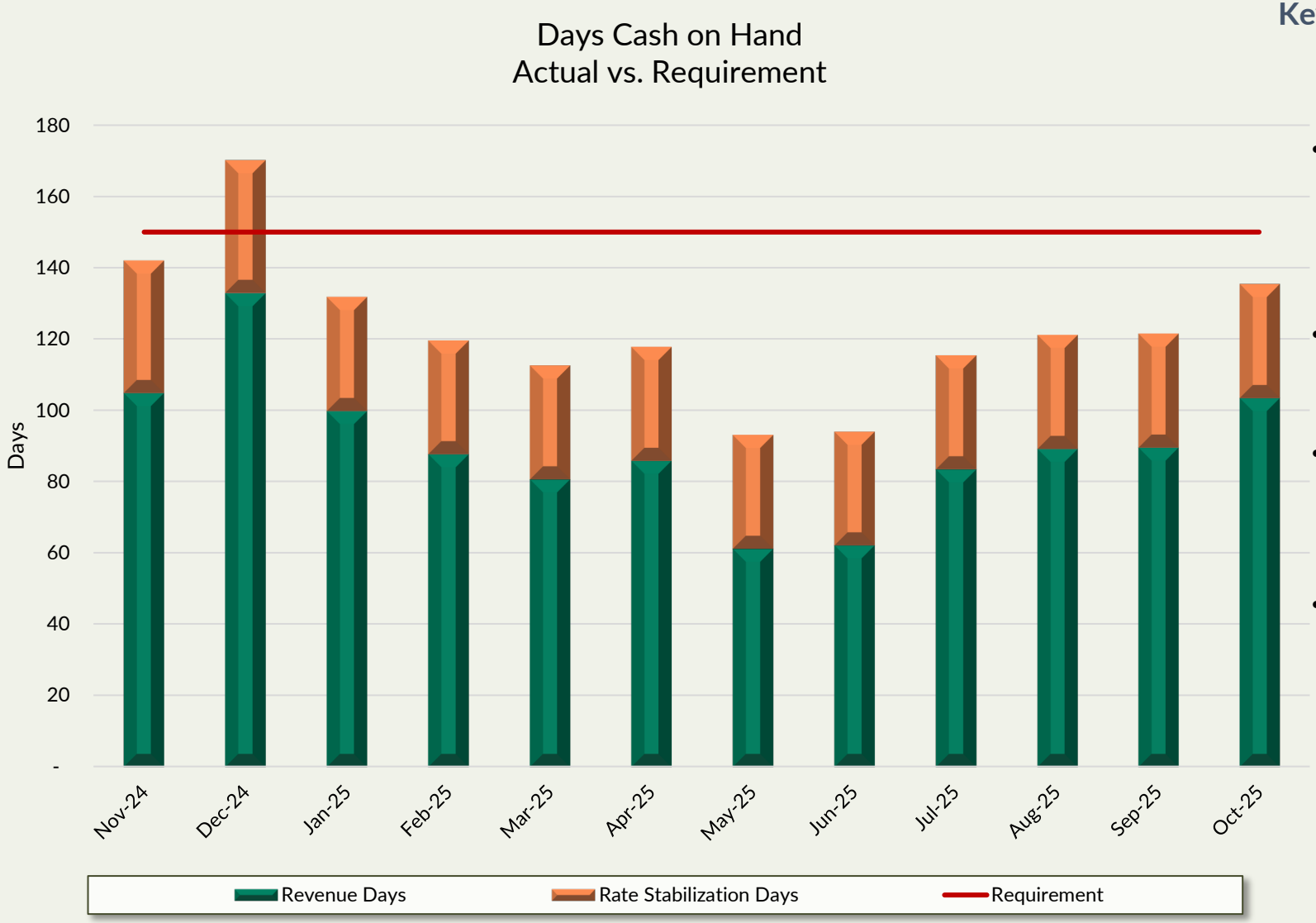


Water System Treasury Report

Unrestricted Reserve Days Cash on Hand
10/31/2025: 135 Days
Requirement: 150 Days

Return on Investments
10/31/2025: 4.39%
10/31/2024: 4.90%

Key Performance Indicators



- The Operating Reserve has decreased $0.5M since December 2024, resulting from lower-than-average rate-adjusted consumptive receipts and customer contributions offset by higher-than-average disbursement activity.
- The Operating Reserve increased in October 2025 from the prior month due to lower-than-average disbursement activity.
- The Days Cash on Hand for the Unrestricted Reserves are reported in the graph. The newly adopted 150-day requirement will be phased-in through the 2029 budget cycle.
- The average return on District investments has begun to decline from peak levels seen in 2024 as investments are made at lower yields observed in the current market environment.
  - $1.3M of cash interest income was earned through October 2025, compared to $1.7M through October 2024.

Water System Budget and Forecast

Highlights Through October

Water Retail Sales are slightly under budget due to cold, wet weather in prior months resulting in less demand earlier in the year.

Water Wholesale Sales are under budget due to lower consumption as seen in Retail Sales.

Purchased Water is under budget due to scheduled shutdowns for maintenance on the City of Everett Water Filtration Plant and lower consumption.



	($000's) YTD Budget through October	YTD Results through October	($000's) 2025 Budget	2025 Projection
Operating Revenues				
Water Retail Sales	$ 15,647	$ 14,627	$ 18,080	$ 17,060
Water Wholesale Sales	653	621	774	742
Other Operating Revenues	342	442	410	510
Total Operating Revenues	**$ 16,642**	**$ 15,690**	**$ 19,264**	**$ 18,312**
Operating Expenses				
Purchased Water	$ 4,257	$ 3,572	$ 4,889	4,204
Operations & Maintenance	9,413	8,373	11,296	10,151
Taxes	818	801	945	928
Depreciation	3,181	3,353	3,818	3,989
Total Operating Expenses	**$ 17,669**	**$ 16,099**	**$ 20,948**	**$ 19,272**
Net Operating Income	**$ (1,027)**	**$ (409)**	**$ (1,684)**	**$ (960)**
Interest Income & Other	837	1,393	1,004	1,560
Interest Charges	(958)	(761)	(1,149)	(953)
Contributions	3,527	1,611	4,232	2,316
Net Income	**$ 2,379**	**$ 1,833**	**$ 2,404**	**$ 1,963**
Capital Expenditures	12,719	9,256	14,555	11,362

Water System Project Status Report ($000's)

YTD Budget	YTD Results	2025 Budget	2025 Forecast
$12,719	$9,526	$14,555	$11,362

Projects in Process:

- Kayak Reservoir No. 2 construction is close to completion; the interior tank coating is complete, exterior tank coating is complete, piping/vaults/electrical in October/November, and the reservoir fill & final site work in November/December.
- Burn Rd Reservoir permit submittal occurred in August with a target project bid in December and construction to begin in 2026.
- 18th St SE / 126th Dr SE / 19th Pl SE Main Replacement has 60-calendar days to construct with the anticipated wrap up in December.
- Jordan Creek Bridge Water Main Relocation was bid as an Interlocal Agreement (ILA) with Snohomish County. Installation of a new main on both sides of the bridge. The bridge deck portion of the water main is complete and awaiting final payments.
- AMI / Connect Up for Water through October is 88% deployed or ~20,600 meters installed.
- Overall, capital spend is currently under budget due to project timing and final billings.





BUSINESS OF THE COMMISSION

Meeting Date: December 2, 2025 **Agenda Item:** 9D

TITLE:

Consideration of Election of Commission Officers for the Year 2026

SUBMITTED FOR: Commission Business

Commission	Allison Morrison	8037
Department	*Contact*	*Extension*

Date of Previous Briefing: _____

Estimated Expenditure: _____ Presentation Planned ☐

ACTION REQUIRED:

☐ Decision Preparation
☐ Policy Discussion
☐ Policy Decision
☐ Statutory
☒ Incidental (Information)
☐ Monitoring Report

SUMMARY STATEMENT:

Identify the relevant Board policies and impacts:

Governance Process, GP-4(8), Agenda Planning, states "At the first regular Commission meeting in December of each year, the Commission shall elect officers of the Board to serve for terms of one year or until such time as a successor has been selected for each such officer position. These terms will commence at the time of the first regular meeting in January of the year following election."

List Attachments:
None

BUSINESS OF THE COMMISSION

Meeting Date: December 2, 2025 **Agenda Item:** 10A

TITLE

Governance Planning Calendar

SUBMITTED FOR: Governance Planning

Commission	Allison Morrison	8037
Department	*Contact*	*Extension*

Date of Previous Briefing: _____

Estimated Expenditure: _____ Presentation Planned ☐

ACTION REQUIRED:

☒ Decision Preparation
☐ Policy Discussion
☐ Policy Decision
☐ Statutory

☐ Incidental (Information)

☐ Monitoring Report

SUMMARY STATEMENT:

Identify the relevant Board policies and impacts:

Governance Process, Agenda Planning, GP-4: To accomplish its job products with a governance style consistent with Board policies, the Board will follow an annual agenda ….

The Planning Calendar is enclosed for Board review.

List Attachments:
Governance Planning Calendar

Governance Planning Calendar – 2025

To Be Scheduled

- Facilities Comprehensive Plan
- Training Center Rentals
- Active Threat Awareness

To Be Scheduled

- ERMC Policy Update
- New ERMC Framework

For Planning Purposes Only and Subject to Change at any Time

Governance Planning Calendar – 2025

December 2, 2025

- ~~Media~~ (moved to December 16)
- Connect Up Quarterly Update
- Audit Activity Update
- ~~Ruby Flats Solar Project Briefing~~ (Moved to December 16)
- Energy Risk Management Report
- Water Supply Update
- Purchase of Property for Future 115kV Ring Bus
- Public Hearing
  →2025 IRP Public Hearing
  →2025 CEIP Public Hearing
  →2025 CPA Public Hearing
- Public Hearing and Action:
  →Adopt 2026 Budget
  →2026 Water Utility General Retail Rates
  →Pole Attachments
  →Rates 2026
- Monitoring Report:
  →Financial Planning and Budgeting Monitoring Report
- Elect Board Officers for the Year 2026
- Proposed 2026 Governance Planning Calendar

December 11, 2025

Special Meeting:

North Camano Substation Ribbon Cutting

For Planning Purposes Only and Subject to Change at any Time

Governance Planning Calendar – 2025

December 16, 2025

- Community Engagement
- Media
- SnoSMART Update
- Ruby Flats Solar Project Briefing
- Public Hearing and Action:
  - →Disposal of Surplus Property - 1st Quarter 2026
  - →Confirm Final Assessment Roll for LUD No.68
  - →Adopt 2025 IRP
  - →Adopt 2025 CEIP
  - →Adopt 2025 CPA
- Adopt 2026 Governance Planning Calendar

For Planning Purposes Only and Subject to Change at any Time

Governance Planning Calendar – 2025

January

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For Planning Purposes Only and Subject to Change at any Time

BUSINESS OF THE COMMISSION

Meeting Date: December 2, 2025 **Agenda Item:** 10B

TITLE:

Proposed 2026 Governance Planning Calendar

SUBMITTED FOR: Governance Planning

Commission	Allison Morrison	8037
Department	*Contact*	*Extension*

Date of Previous Briefing:
Estimated Expenditure: Presentation Planned ☐

ACTION REQUIRED:

☒ Decision Preparation
☐ Policy Discussion
☐ Policy Decision
☐ Statutory
☐ Incidental (Information)
☐ Monitoring Report

SUMMARY STATEMENT:

Identify the relevant Board policies and impacts:

Governance Process, Agenda Planning, GP-4: To accomplish its job products with a governance style consistent with Board policies, the Board will follow an annual agenda

List Attachments:
Proposed 2026 Governance Planning Calendar

Governance Planning Calendar - 2026

To Be Scheduled	• Active Threat Awareness • ERMC Policy Update • New ERMC Framework • Facilities Comprehensive Plan • Training Center Rentals

For Planning Purposes Only and Subject to Change at any Time

Governance Planning Calendar - 2026

Date	Agenda Items
January 6, 2026	**Briefing and Study Session:** • Media • Legislative **Public Hearing and Action:** •
January 20, 2026	**Briefing and Study Session:** • Legislative • ERM – Strategic Risk Reporting

For Planning Purposes Only and Subject to Change at any Time

Governance Planning Calendar - 2026

Date	Agenda Items
February 3, 2026	**Briefing and Study Session:** • Media • Legislative
February 17, 2026	**Briefing and Study Session:** • Legislative • Strategic Plan

For Planning Purposes Only and Subject to Change at any Time

Governance Planning Calendar - 2026

Date	Agenda Items
March 3, 2026	Briefing and Study Session: • Media • Legislative
March 17, 2026	Briefing and Study Session: • Legislative Public Hearing and Action: • Disposal of Surplus Property – 2nd Quarter 2026

For Planning Purposes Only and Subject to Change at any Time

Governance Planning Calendar - 2026

Date	Agenda Items
April 7, 2026	Briefing and Study Session: • Media • Legislative Closing Report
April 21, 2026	Briefing and Study Session: • Community Engagement • Water Supply Update • Energy Risk Management Report • 2026 Audit Results Public Utility District No. 1 of Snohomish County Monitoring Report: • 4th Quarter 2025 Financial Conditions and Activities

For Planning Purposes Only and Subject to Change at any Time

Governance Planning Calendar - 2026

Date	Agenda Items
May 5, 2026	Briefing and Study Session: • Media
May 26, 2026	Briefing and Study Session:

For Planning Purposes Only and Subject to Change at any Time

Governance Planning Calendar - 2026

Date	Agenda Items
June 9, 2026	Briefing and Study Session: • Media Monitoring Report: • 1st Quarter 2026 Financial Conditions and Activities
June 23, 2026	Briefing and Study Session: • Connect Up Public Hearing and Action: • Disposal of Surplus Property – 3rd Quarter

For Planning Purposes Only and Subject to Change at any Time

Governance Planning Calendar - 2026

Date	Agenda Items
July 7, 2026	Briefing and Study Session: • Media • SnoSMART
July 21, 2026	Briefing and Study Session: • Water Supply Update • Energy Risk Management Report Monitoring Report: • Asset Protection

For Planning Purposes Only and Subject to Change at any Time

Governance Planning Calendar - 2026

Date	Agenda Items
August 4, 2026	Briefing and Study Session: • Media
August 18, 2026	Briefing and Study Session: • Strategic Plan 2027 Budget Notice of Public Hearing Monitoring Report: • 2nd Quarter 2026 Financial Conditions and Activities

For Planning Purposes Only and Subject to Change at any Time

Governance Planning Calendar - 2026

Date	Agenda Items
September 1, 2026	Briefing and Study Session: • Media •
September 15, 2026	Briefing and Study Session: • Connect Up Quarterly Update Public Hearing and Action: • Disposal of Surplus Property – 4th Quarter

For Planning Purposes Only and Subject to Change at any Time

Governance Planning Calendar - 2026

Date	Agenda Items
October 6, 2026	Briefing and Study Session: • Media Public Hearing: • Open the 2027 Proposed Budget Public Hearing
October 20, 2026	Briefing and Study Session: • Water Supply Update • Energy Risk Management Report Public Hearing: • Continue Proposed 2027 Budget Public Hearing

For Planning Purposes Only and Subject to Change at any Time

Governance Planning Calendar - 2026

Date	Agenda Items
November 3, 2026	Briefing and Study Session: • Media • Strategic Plan Quarterly Update Public Hearing: • Continue Proposed 2027 Budget Public Hearing Monitoring Report: • 3rd Quarter 2026 Financial Conditions and Activities
November 17, 2026	Briefing and Study Session: • Community Engagement Public Hearing: • Continue Proposed 2027 Budget Public Hearing

For Planning Purposes Only and Subject to Change at any Time

Governance Planning Calendar - 2026

Date	Agenda Items
December 1, 2026	Briefing and Study Session: • Media • Connect Up • Audit Activity Update Public Hearing and Action: • Adopt 2027 Budget Monitoring Report: • Annual Financial Planning and Budgeting
December 15, 2026	Briefing and Study Session: • Community Engagement • SnoSMART Public Hearing and Action: • Roll for LUD No. XX • Disposal of Surplus Property – 1st Quarter

For Planning Purposes Only and Subject to Change at any Time

Governance Planning Calendar - 2026

2026 Year-at-a-Glance Calendar

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February

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March

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April

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May

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July

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August

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November

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	Holiday	#	Commission Meetings
	APPA National Conference - June 26 - July 1 (Boston, MA)		APPA Legislative Rally - February 23-25 (Washington, DC)
	ENW Board Meetings - (Olympa, WA, Tri-Cities, WA)	#	PPC/PNUCC Meetings - (Portland, OR)
	NWPPA Annual Conference - May 18-21 (Spokane, Wa)		

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